STATE OF CALIFORNIA – THE RESOURCES AGENCY
BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of,	)
	)Docket No. 11-IEP-1L
	)
Preparation of the 2011	)
Integrated Energy Policy Report	)
(2011 IEPR)	)

Transportation Committee Workshop:
Transportation Fuel Infrastructure Issues

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

MONDAY, MAY 11, 2011
9:30 A.M.

Reported by:
Peter Petty

COMMISSIONERS

James D. Boyd, Vice Chair and Presiding Member,
Transportation Committee
Tim Olson, His Advisor
Carla Peterman, Commissioner and Associate Member,
IEPR Committee
Saul Gomez, Her Advisor

STAFF

Suzanne Korosec, IEPR Lead
Malachi Weng-Gutierrez
Gordon Schremp, Senior Fuels Analyst, Fuels and
Transportation Division

Also Present (* Via WebEx)

Presenters

John Brautigan, Valero
Tim Carmichael, NGVC
Tom Turrentine, UCD
Ed Heydorn, Air Products
*Steve Eckhardt, Linde
Matt Horton, Propel Biofuels
Jim Uihlein, Chevron
Eric Bowen, Renewable Energy Group, Inc.,
CA Biodiesel Alliance
Matt Tobin, Kinder Morgan PL
Jim Iacoponi, Propel Biofuels
Chuck White, Waste Management
Michael Waugh, CARB

Panelists

Richard Lowenthal, Coulomb
Paul Heitmann, Ecotality
Joel Pointon, San Diego Gas & Electric (SDG&E)
Russell Vare, Nissan
Dan Bowermaster, Pacific Gas & Electric (PG&E)

Public Comment

Dwight MacCurdy, SMUD
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P R O C E E D I N G S

MAY 11, 2011 9:34 A.M.

VICE CHAIR BOYD: Welcome to this Transportation Committee Workshop. The Notice of April 27th was pretty specific as to the mission and purpose of this workshop; Preparation of the 2011 Integrated Energy Policy Report is our target. I am Jim Boyd, the Presiding Member of the Transportation Committee and, as you may have noticed at the time the Workshop Notice went out, I was the lone Commissioner on the Transportation Committee, however, subsequent to that Workshop Notice, our newest Commissioner sitting to my left, Carla Peterman, became the Associate Member of the Transportation Committee, so I am no longer as lonely as I was there for a period of time. And in a few minutes, I will, after giving some background on this, I will ask Carla if she'd like to say some – offer the opportunity, anyway, to make some comments about being a member of this committee and the workshop for today. It is a Transportation Committee Workshop on Transportation Fuel Infrastructure Issues.

The workshop today is being webcast and you'll probably hear more about that in just a minute from Ms. Korosec when I turn the opportunity over to her. The purpose, as enunciated in the Hearing Notice is to discuss Transportation Fuel Infrastructure and the issues confronting California related thereto, particularly with reference to the production, the delivery, the distribution, and the storage of transportation fuels, as well as the adequacy of supply of petroleum, renewable, and alternative fuels. And, of course, you can’t talk about these issues without reference to the demand therefore.

A set of key questions were laid out in the hearing notice and I will not repeat that. The background for IEPR production and hearings therefore, I’m sure, will be discussed by Ms. Korosec, so I won’t go into that. I will just point out there was an attachment to the hearing notice, referencing issues to be discussed that laid out a large number of issues that we and the staff would like to hear from the public and stakeholders on, with reference to this overall topic. And in addition to the testimony we expect to hear today and the presentations by staff, there of course is an opportunity for stakeholders and the public to make written comments and you will be reminded of the procedures and the timetable for that, it’s referenced in the Hearing Notice.

And with that, I would like to offer the opportunity to my new associate committee member to make a few comments before we go back and return to the agenda and turn the issue over to Ms. Korosec, who also, I'm sure, has to tell us about emergency procedures and how to evacuate the building and the other things required of such hearings. Ms. Peterman.

COMMISSIONER PETERMAN: Good morning. Thank you, Commissioner Boyd. Hello, everyone. Glad to have been selected to participate on the Transportation Committee. Considering the share of greenhouse gases that a transportation sector can contribute and its role in our economy, I think it's a very important committee to be on, particularly our work exploring other opportunities for alternative fuels. The infrastructure issues are key and are an area where the State can contribute great insight, and so looking forward to the comments in this discussion today and working with all of you going forward. Thank you.

VICE CHAIR BOYD: Thank you. Would you like to introduce your Advisor?

COMMISSIONER PETERMAN: Yes, I would.

VICE CHAIR BOYD: Because I just met him. He's that new.

COMMISSIONER PETERMAN: Thank you. I have a new Advisor, Saul Gomez, and he comes to us with a background in renewables, electricity infrastructure and transportation. He has experience with the Legislature and CERT, and I think he will be a valuable asset to my team, to the Commission, and to this Committee.

VICE CHAIR BOYD: Thank you. And I would note that my Advisors are conspicuously absent and I hope to be joined by at least one of them as the day progresses, but they're both taking care of fire drills that are consistent around here, and I hope to be joined by at least Tim Olson in the not too distant future, but he's taking care of some issues for me, plus they know I've been around here so long that I probably wouldn't give them a chance to speak anyway, or maybe they think I don't need the help that I know that I need on this subject. In any event, Ms. Korosec, having totally blown your calendar and done the introduction on your agenda and done our opening comments, I'll turn it back to you. I thought it would be better to introduce the subject from up here before you get to the fire drills and etc. etc. So Suzanne, if you would please.

MS. KOROSEC: All right. Good morning, I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit. The Energy Commission produces an IEPR every two years that includes assessments and forecasts of energy supply, demand, production, transport, delivery, and distribution for the State's energy sectors, including the transportation fuel sector, and these assessments and forecasts are used to develop energy policies that are intended to ensure that California has enough energy to meet its needs and that energy is reliable, affordable, and environmentally benign. This year, the IEPR schedule is consistent with past IEPRs, we plan to have a draft report out in late September with a hearing on the draft in mid-October, and hope to adopt near the end of November.

As Commissioner Boyd noted, I need to cover some housekeeping items before we get started. For those of you who may not have been here before, restrooms are in the atrium, out the double doors and to your left. The glass doors near the restrooms, please be aware those are alarmed, they are for staff use only, if you try to go out, you will trigger an alarm. We have a snack shop on the second floor at the top of the atrium stairs under the white awning where you can get coffee, and if there’s an emergency and we need to evacuate the building, please follow the staff out the door to the park that is diagonal to the building, and wait there until we’re told that it’s safe to return.

Today’s workshop is being broadcast through our WebEx conferencing system and you need to be aware that you are being recorded. We will make an audio recording available on our website in a couple of days, and we'll have a written transcript available within about two weeks.

We have a public comment period today at the end of the agenda and, during that period, we'd like you to please fill out blue cards, or comment cards, those are available on the table out in the foyer, with your name and affiliation, and please give those to Jessie who is here near the WebEx console. We'll take comments first from those of you here in the room, followed by comments from those who are participating via WebEx. For those of you in the room, when it's time for you to speak, please come up to the microphone at the center podium so we can make sure your comments are heard by those on WebEx and also appear in the transcript. It's also helpful if you can give our transcriber your business card so we make sure that your name and affiliation are correct. WebEx participants can either use the chat or raised hand feature to let the Coordinator know that you have a question or comment, we'll either convey your question or open your line so you can ask it yourself at the appropriate time. Anyone who is participating by phone only and is not logged into WebEx, we'll open your phone lines at the very end of the public comment period to give you an opportunity to speak.

We're accepting written comments on today's topics until close of business May 23rd, and the notice for today's workshop, which is available on the table in the foyer and also on our website outlines the process for submitting comments to the IEPR Docket. And with that, I'll turn it over to Malachi.

MR. WENG-GUTIERREZ: Good morning, Commissioners.

VICE CHAIR BOYD: Good morning, Malachi. Somebody should respond.

MR. WENG-GUTIERREZ: All right, so, again, today we are talking about transportation fuel infrastructure issues. I'm just going to be giving a quick overview, letting the speakers who we have lined up today speak to most of the issues. Hopefully, we'll have many of the questions that we had posted in our notice in the attachments addressed in the conversations that ensue today.

So, in the morning we'll be talking basically about the Infrastructure and Demand Integration methodology that we'll be using for this IEPR cycle. We'll follow that with a discussion about Retail Refueling and Recharging Infrastructure and the issues that could arise in those areas, and then, after lunch, we will have a few speakers that will also be in the

Retail Fueling and Recharging Infrastructure topic on that topic. And then, at the end of the day, we'll have a couple of other items, the Renewable Fuels: Supply Import & Distribution topic, and then the Crude Oil Import Forecast and the High Carbon Intensity Crude Oil (HCICO) screening topic, which all will be very interesting, I'm sure. So, at the very end of the day, as Suzanne mentioned, we will have a public comment period and hopefully, as we have it outlined, we should be done about 5:00 today. So it is a full day and we'll try to move it along and ensure that we have adequate time for both public comment and questions and discussions.

I had this slide in here just in case it wasn't covered, but I think Commissioner Boyd you already covered it, and Suzanne also mentioned it. I just wanted to highlight the reliability component, the security element, and then the element of diversifying the energy supplies as being kind of important elements of this requirement.

VICE CHAIR BOYD: Well, thank you for doing that because I neglected to push the subject hard enough. I didn't want to flash that slide in front of people two or three times during the day.

MR. WENG-GUTIERREZ: There is a lot to that slide, so…. So, in the Fuels and Transportation Division, we do a number of things and I'm just highlighting a few of the elements of the activities that we perform there. As we presented in our February 24th workshop, we actually develop fuel price scenarios and evaluations for our Demand Forecasts, we develop our Demand Forecasts throughout the year, and then we intend to present them on August 16th in a workshop on our outputs. In addition to the General Over-Arching Transportation and Fuels, I also wanted to pull out the transportation - the electricity transportation Demand Forecasts that we produce in the Fuels and Transportation Division. That is a forecast that we produce and we provide to the Demand Analysis Office, that they then include into their analyses of demand, so they add that to their overall residential and commercial industrial demand for electricity, and they get from us the transportation component; so, they look to us as the source for that demand.

In addition to those items, we also quantify regional supply and demand trends historically and also going forward, to identify potential issues that could arise in regional demand. So, as I'm sure Gordon will mention, as we've mentioned in the past, we look at a number of states, not just California, but also Arizona and some other neighboring states, to see how their demand requirements might influence our infrastructure requirements in the state to supply them with their transportation fuels, as well.

Of course, we evaluate infrastructure adequacy issues and we consider our projected demand scenarios in those evaluations, and we look at the sources and production capacity of different types of transportation fuels in our analyses.

So, in our February 24th Workshop, we talked about a couple of overarching themes that we would be kind of talking about throughout our analyses, this is one of them, we've gotten some feedback from the Commissioners and others and I think we're going to highlight energy security as one of the elements that we will be looking to and discussing in our report. So, the two elements that we're focusing on when we talk about energy security are diversification and then the sourcing of different fuels, transportation fuels. And as I say here, obviously the idea – the benefit of diversification would be to limit the exposure of the transportation market to single fuels, or to a very small number of fuels. Of course, there is the potential if you move from one field to another, if the new field that you're having introduced has a high price volatility or other complications, you need to consider that in your evaluation and in your recommendations for activities associated with increasing energy security.

The fuel sources should be both reliable, stable, and should meet the California specifications and this, as we diversify our fuels, there are added infrastructure requirements. All of that adds to the complexity of distributing transportation fuels in California and all those things need to be kind of considered and included in our analysis.

This is a slide that I showed at our February 24th workshop. I've added the actual goals, the AB 1007 goals that were identified for alternative fuel use and, again, this is a California-wide transportation fuel demand. And the two lines in there are from our 2009 IEPR, so the red one is our low petroleum demand, which would correspond with a high alternative fuel use, and then the blue line obviously is our high petroleum demand, so that would equate to a lower alternative fuel use. So, you can see in the early years, the green triangles there are the goals – nine percent in 2011, eleven percent in 2017. We intend to meet those goals pretty easily. The goal that we are not meeting under our IEPR 2009 analysis was the 2022 goal and you can see that that's fairly – we're pretty shy of meeting that goal.

Of course, the new IEPR analysis may hold different results and we will have that for you in August. One of the things that I wanted to – it's not illustrated here, but I did want to point out, was that the primary component of this alternative fuel use and the large gain in alternative fuel use from 2012 to 2022 is due to ethanol use in California, primarily due to the RFS2 adjustment we did to our demand analysis. So, the major component of the alternative fuels that are being observed here are primarily natural gas and ethanol.

Overall, this is another slide that I've presented before, but it basically shows our inputs at the top. In the middle where it's kind of bolded squares or rectangles there, those are kind of the sectors or the areas of demand that we primarily look at. Results in our California field demand, which is the green box in the lower left, and that both is relevant to and also gets information from the supply – California fuel supply component. Obviously, today we're talking about the transportation energy infrastructure, which is influenced both by supply capacity, as well as what we intend to be future demand. So there's an interaction there between the supply and demand and the infrastructure requirement that I wanted to just illustrate there.

Our demand scenario methodology, we're going to have a two-step approach, we're going to be running the initial models to get our base demand numbers and those will be dependent upon all of our inputs and the policy scenario developments that we've defined, and we mentioned in our February 24th workshop. That initial modeling activity would then be followed by a post-processing activity, which we would adjust the demand for different fuel selection processes, as well as sectors, not necessarily included in our demand models, and then also adjusting for different policies.

And so, specifically, the post-processing activities for the fuel selection in sectors, because of the bi-fuel component, or the multiple fuel use for PHEVs and E85 FFVs, that's something we have to kind of evaluate outside of the current model. We do have specifications for those decisions being made on the basis of infrastructure availability and pricing, so those are done outside of the existing model structure. In addition, we typically evaluate off-road fuel consumption and add that to our General Demand Forecast, and then also, as post-process activity, we have analyzed certain other policies of program compliance.

We have to basically evaluate our outputs and make sure we see how close we are to program compliance given their current estimates for vehicle population, to comply with that standard, given their schedule. And then we also look at the RFS2, or the Renewable Fuels Standard, and the Low Carbon Fuel Standard policies, and those will both be post-processing activities that we will be handling in this IEPR cycle.

I’m going to turn the mic over to Gordon and have him speak in a little bit more detail about those post-processing activities and how that will be handled for the Renewable Fuel Standard and LCFS.

MR. SCHREMP: Thank you, Jesse, thank you, Malachi. Good morning, Commissioners, new Advisor. My name is Gordon Schremp, I’m a Senior Fuels Analyst in the Fuels and Transportation Division at the California Energy Commission. As Malachi mentioned, I will be going through some slides talking about some of the post-processing work.

It’s important to note, as Commissioner Boyd stated at the outset, that part of this process is to get feedback from stakeholders, people who are experts in the industry, people who work in these subject areas as business or NGOs, provide us, please, with your experience and input as we move forward in the process.

We can only be as good and accurate as the information we receive and sort of the education we receive as part of our ongoing process. So, to that end, we try to be as transparent as feasible and provide stakeholders with clarity on what our assumptions are going to be. People can disagree with them, but we want to be clear on what we’re assuming because it’s very important to the Demand Forecast, the infrastructure assessments, and what we assume is going to be sort of part of our baseline. So, the purpose of this slide is to show you some of the key assumptions we’re making, moving forward, and please provide comment to us. Suzanne covered the close date of May 23rd; feel free to weigh in on some of these subjects.

But it’s very important that the Renewable Fuel Standard, the Federal Regulation, is a fair share compliance, it’s a company-wide compliance in the United States. For purposes of analysis, we’re assuming fair share is meant by actually blending and using those volumes in California and not necessarily over-complying in other regions of the U.S. and applying those credits to your nationwide obligations.

Further, people will talk about this a little bit later, but the new changes by the U.S. EPA to allow E15 and about two-thirds of the existing light-duty and

SUV fleet is something we don’t think will happen in California any time soon, in fact, over the forecast period. So, is it feasible to occur? Yes. Many steps, many years to go through to even get to that point, but there are lots of issues associated with E15 that others will speak to. So, for our purposes, we’re assuming E10 is the maximum low level blend wall.

There are many different carbon intensities, those can be changing with new information provided to the Air Resources Board, and we are going with the current versions as posted by the Air Board online. We understand the indirect land use change – and there is both direct and indirect as part of the overall total carbon intensity of specific fuels – we’re assuming that the indirect land use change will remain as is for purposes of our calculation, but we recognize that this issue is going to continue to be discussed by the Air Board and the Advisory Panel members, and ultimately reach a resolution that is indeterminate at this time, meaning a 50 percent reduction in the indirect land use change can possibly be offset by other modifications to information that go into calculating direct and indirect carbon intensities of fuels. So, those are assumptions, please feel free to compel us to change our mind.

As I mentioned, the RFS2 Federal requirement, it is a company-wide volume, renewable volume obligation. And so it’s not a per gallon regulation. So, primarily more ethanol, more than we can use in low level gas blends, it’s going to lead to E85.

There were concerns about feedstock being used to convert to fuel and putting pressure on feedstock prices, and so that’s something why I think U.S. EPA capped it at 14 billion gallons. But certainly, it’s going to displace gasoline as it did in our 2009 Forecast, it will do it again this go-round, as well, and we’re looking at a need for increased infrastructure, of course, what we’re here today.

This slide is only intended to illustrate that the Regulation has some concerns at this point, the main is cellulosic biofuels, maybe over-reaching at this point, it’s either been significantly downgraded in the obligation by U.S. EPA, 250 million gallons became, I think, approximately six million gallons for 2011, it’s half a billion next year, we certainly don’t see that kind of capacity available at this point in time, and I don’t think EIA or U.S. EPA does either, so that will be downgraded. So this has concerns about trying to project volumes and, in particular, specific types of renewable fuels that are important, that have infrastructure and fuel availability differences.

Post-processing does change the forecast results that Malachi discussed as part of our modeling work, and that will do primarily – push down the gasoline component, the petroleum hydrocarbon component of the gassing demand. So it’s going to decline lower than it is today. And we’ll elevate E85 beyond what the modeling results with, say, consumers and vehicle and fuel availability would dictate normally. So it’s going to be sort of a forcing function and that has other issues for business purposes, as well as getting consumers to consume that much E85 in California.

We are close to the blend wall in the United States. E15 has not been officially approved, there are labeling requirements, there are warranty issues, so this is not a given to start any time soon, even in the United States, but there are certainly many proponents out there that want to move forward on E10, but we’re assuming in California that E10 blend wall is going to be a hard cap in low level blends throughout the forecast period.

VICE CHAIR BOYD: Gordon, question?

MR. SCHREMP: Yes.

VICE CHAIR BOYD: Does it take E15 for the nation to meet the RFS goals that have been established?

MR. SCHREMP: The use of E15, or the initial request to use a higher blend E15, was done because there was concern heating the blend wall, we would not be able to blend all the ethanol that you're referring to under RFS2 obligations; however, E15 does not get one to the end of the RFS2 obligations, all it does is delay the inevitable, meaning hitting the low level blend wall, whether it's E10, E12, E15, by a couple of years. So, it won't necessarily solve and obviate the need to sell lots of E85, it will just delay that.

VICE CHAIR BOYD: So it's a trade-off potentially between increasing the ethanol component of gasoline or selling a lot more E85?

MR. SCHREMP: Right, which has retail infrastructure cost and who will invest implications, which has adequacy if Flex Fuel Vehicle is a big issue; so, yes, it's very important, but it won't be a silver bullet if, in fact –

VICE CHAIR BOYD: I may be getting ahead of you, but the other component in my mind is the fact that the Renewable Fuels Standard goals are predicated on so much from corn, so much from cellulosic sources, and the Federal Government has repeatedly relaxed or delayed the cellulosic component for lack of much cellulosic ethanol. I presume that, too, enters into the discussions of the need for E15 or how much E85 you need to meet the Renewable Fuels Standard if the standard keeps getting delayed, so to speak.

MR. SCHREMP: That's a very good point. It's unknown exactly how U.S. EPA will continue to handle the inadequate availability of cellulosic ethanol in commercial volumes. Will they modify the total volume of renewable fuels under the mandate, modify only this portion of the advance and shift it into more advanced, which would be Brazilian ethanol, or shift it into biomass-based diesel, which has lot of other issues we haven't talked about? So, just saying, no, it's not that much and we don't change anything else is possible, but it's possible they'll just shift that into some of the other categories. So, once again, that's sort of a challenge not only for us trying to do some forward thinking demand analysis, but certainly a challenge for those who are striving to comply each and every year with its obligation throughout the nation and in California. So, it's created a great deal of uncertainty. It would be valuable if U.S. EPA weighed in on this, and ultimately Congress has to modify these requirements, so we would hope that there would be a continued dialogue, an expanded dialogue on how to modify so that we have an achievable set of Federal goals here.

VICE CHAIR BOYD: Thank you.

MR. SCHREMP: So why would we care about looking at how much more E85? Well, we think there is a significant amount of retail infrastructure that would be required. You see all kinds of lines on this chart, this is from 2009, and you see a line like 30,000 additional dispensers, well, that's quite a bit, and 5,000 down here. So, the low case has us looking at California needing quite a few more dispensers to market E85, depending on the average throughput per dispenser, change the volume, change the throughput calculation, and then you get a very large variation in the demand. However you look at this, though, it's a very daunting increase in the number of dispensers. Propel, who is going to speak today, has been installing dispensers at existing retail establishment, as has Pearson Biofuels, so companies are out there endeavoring to improve the availability of E85 at retail, but there's an awful lot of demand for these kinds of dispensers and capability to be seen and this will be a large focus of our infrastructure renewable fuel assessment at retail.

COMMISSIONER PETERMAN: Gordon?

MR. SCHREMP: Yes.

COMMISSIONER PETERMAN: Why do we see a decline in dispensers in later years under some of the case scenarios?

MR. SCHREMP: Good question. This is essentially an artifact of going up to 2022 where the RFS2 obligation stops. Clearly, we believe they won't just plateau, but they'll likely keep increasing, and so we've held that steady and, when you do that, the actual demand will decline because there's total fuels going up, so the E85 portion goes down. So it's really more of an artifact, so if we were to, for example, make an assumption that the renewable fuel components go up one percent per year, then these lines wouldn't just peak and decline, they would continue rising, but possibly a different slope.

The other post-processing assessment is the Low Carbon Fuel Standard, the California Regulation. It is a per gallon carbon intensity, not total volume, so it doesn't matter how much gas and diesel fuel is sold in California, ultimately, every gallon, you know, each quarter, has to fully comply when companies, obligated parties, sort of true up their debts and credits under the carbon umbrella. So this regulation began in 2011, January, there are still a number of important issues yet to be resolved in this regulation. Credit trading, like in the renewable identification number system in the Federal program, transparent credits, a market one can go into and purchase as part of your obligation strategy, does not yet exist in California, although the regulation is underway. There is a proposed screening for crude oils to – the Air Resources Board would not want to have certain high carbon intensity crude oils used in California. If they are, the incremental carbon should be offset, and we will talk about that a little bit later, after lunch.

The indirect land use, I already mentioned, that’s a big issue, but enough information and no resolution on this issue to date and we don’t expect resolution in time for us to finalize our forecast, so we will go with the existing indirect land use change carbon intensities today.

So we’ve done some preliminary analysis and the concern under RFS2 is more E85, diesel is very low, we haven’t looked at – we haven’t completed looking at the Low Carbon Fuel Standard; unlike the Federal requirement, there is a very small amount of biodiesel under the Federal Standard. California, on the other hand, there could be a strong demand for bio and renewable diesel to lower the carbon intensity of diesel gallons. So that’s the significant difference. The LCFS will change the different flavors one would want to use in California, but not necessarily increase the total volume of renewables on the gasoline side of the ledger, but for diesel, much more so. So, the Federal requirement isn't a big deal on the diesel side of the equation, but even though it's a small amount, there are problems, and some will speak to this in terms of lack of biodiesel availability in the United States and very high prices.

So we're very concerned looking mid to longer term in the forecast, insufficient supply of low carbon fuels that are going to be needed. So that's a big deal and infrastructure, of course, to import and distribute those. And then we expect, certainly, that fuel prices will increase. These fuels are more expensive and we expect them to become even more expensive as demand for certain types of low carbon intensity fuels start to really kick in, not necessarily this year, but the next two, three, to four years. And if you look at some of the RIN credit prices in those markets, they've gone up rather dramatically and some of those volume requirements are very modest, so that's certainly a concern, but we have no credit trading information to look at, at this point in time.

So, what does it look like? Well, in total, it changes the mix. The blue is Brazilian at the bottom. These two colors, the top two, are Midwest, that gets phased out, its carbon intensity is too high as you move forward in the regulation, and we're using a small amount of all the California ethanol, but very significant volumes of biodiesel, which gets to price availability. No ethanol from Brazil was imported into the United States in all of 2010. And, in fact, Brazil was importing some ethanol, so will the supplies be there? And if they are, at what price increase? So these are definitely concerns. This shows that, if you're selling E85, compliance with the Low Carbon Fuel Standard is easier. You can continue using Midwest ethanol primarily and a little bit of Brazilian and achieve full compliance. But that's only the minority portion of the total gasoline and gasoline-like fuels being sold.

So, our concern is there's no feasible solutions out there at this point in time. Is there time for cellulosic ethanol to become available in commercial quantities, you know, five or six years from now? Yes, there is, however, lack of progress over the last 20, and especially last 10 and five years, it does raise concern about will that be there. So, time will tell and we certainly hope more information is put into our process, as well as U.S. EPA's assessment of the RFS2. So, I think that's it for now. I would be happy to take any questions from the dais at this time.

COMMISSIONER PETERMAN: Gordon, I heard that there were projects looking at sugar-based ethanol in the southern states in the U.S. I was wondering what the status of any U.S. projects along this line.

MR. SCHREMP: I am not aware of any announcements that financing and permitting has been completed, and that a construction schedule has been put into press. We understand that sugarcane-based ethanol in, say, as you mentioned, Southern states, Florida, but especially in the Imperial Valley in California is probably the optimal growing location for sugarcane, even better than Florida. It has some of the cheapest water cost anywhere in the United States. That has been an area of intense investigation by farm cooperatives and Ag associations down there, large farmers, about looking at growing cane and even sugar beets, going down there for the sugar markets, using integration with existing sugar plants and displacing things like the alfalfa that use as much water as cane. So, an awful lot of work has been done on that, but yet no announced construction projects starting soon, so certainly I assume that, not knowing anything else, that the costs are still quite high, otherwise you would see this because there is an RFS2 obligation for advanced that, with sugar-based ethanol would completely qualify, so they certainly have – there is a demand target out there that is not available in the United States, so if you could build it, your competition is going to be Brazil. So we haven't seen that yet, but it doesn't mean it can't happen. Any other questions?

VICE CHAIR BOYD: I'll make a comment and that is, I mean, we're setting up a situation in my mind where California could drive the price of Brazilian ethanol sky high and I think, as a State, and as a nation, we need to think about that.

MR. SCHREMP: Well, I think the President of Brazil is already thinking about things like that with recent announcements to the effect of maybe shifting who has responsibility for setting the ethanol concentration in gasoline, as well as changing how ethanol – or, excuse me – cane mills operate, meaning what ratio of sugar to alcohol production they can get to some maximum or some minimum levels. So there is a recognition about just availability of adequate ethanol supplies to meet Brazil's demand, which their gasoline demand is growing three, four, or five percent per year, unlike that of the United States. So they recognize the concern about adequacy supply, let alone your second point, what will be market clearing prices if there is a large demand pull and the market clearing prices have to be high enough to attract it, and especially to overcome the $.54 import tariff; that's why it's much more expensive.

VICE CHAIR BOYD: Thank you, Gordon.

MR. SCHREMP: Thank you.

VICE CHAIR BOYD: As you are leaving, let me just comment to the audience and stakeholders, when we get to the testimony, I would be interested in hearing from stakeholders about the subject that came up here in this discussion about the possible failure of the nation to reach the RFS goals because of delays in realizing the cellulosic component goals, and what people think about that, and does that address the need of the nation to look at other alternative fuels to realize our overall alternative fuel introduction goals, rather than just our ethanol component thereof. In any event, something I think we would be interested in hearing about if folks have any comments when they make their testimony.

MR. SCHREMP: Well, thank you, Commissioners, and I'll introduce our first presenter of the day, John Brautigan from Valero. John, the mic is yours.

MR. BRAUTIGAN: Good morning. Thank you for letting me speak to you. I'm the Vice President of Strategic and Regulatory Development for Valero. I deal with fuels regulations, from working with the EPA or the State Regulators, giving them advice as to how to write the regulations so we can comply, and going back, working usually as a capital plan for like lowering sulfur in gasoline or diesel, or with the RFS2 and the Low Carbon Fuel Standard, a supply plan for supplying lower carbon fuels, working with the marketing people, we develop a strategy, put it together, and then follow through and make sure that we're in compliance with the regulations.

VICE CHAIR BOYD: Well, welcome, John. I'm thrilled to see that California issued you a Visa to enter the state!

MR. BRAUTIGAN: In the presentation, is it page down? Hang on while my eyes – okay – in the presentation, I'm going to talk about RFS2 and LCFS issues. We see some major compliance concerns getting to the same things that Gordon talked about, just the blend walls and lack of infrastructure, cost of infrastructure, for E85 and just adequacy of infrastructure for importing 100 percent of California's ethanol from Brazil. I'll talk about RFS2 first, then LCFS, have a summary, and then the HCICO, I'll come back later on this afternoon.

I put this in a question and answer format just to try to get right at the issue, I actually got some of the questions from the Energy Commission and we made up some of our own. One of them was, “What if the blend wall remains at E10 in California?” And this is related to the RFS2. Well, yeah, it would hurt RFS2 compliance because at some point you need to blend more than 10 percent ethanol and whatever gasoline and at a company like Valero, we’re making gasoline in California plus outside of California. If California stays at 10, outside of California would have to be even higher. The real question is, I don’t think people are aware of the whole nature of the blend wall issue. You cannot sell E15 today legally, except for Flex Fuel Vehicle. The blend wall is a multi-layer wall, or a barrier. The Sub-Sim regulations is what the EPA issued a waiver for, the waiver is contingent on proper dispenser labeling and a retail survey requirement, which will be established in a final rule that hasn’t been issued yet, it’s still at the Office of Management and Budget, and approval of health effects test under Section 211(b) of the Clean Air Act, so once those three things get done, then as far as in the EPA’s eyes, it’s okay. But then we have additional problems. The RFG regulations will be fixed with the final rule for the labeling, but the CARB regulations for CARB Phase 3A, they don’t allow you to go over 10 percent; the Arizona regulations don't allow you to go over 10 percent. There are many State laws, there are State regulations out there that don't allow you to blend over 10 percent, or that reference ASTM Standards and NIST Standards as being the gasoline in Texas must meet ASTM Standards. Well, the ASTM Standards don't go over 10 percent. And if anybody wants to see a paint drying very slowly, go watch ASTM move on an issue, okay?

Then, you've got the kevlar layers, the warranty issues, and the lack of them for original equipment and extended warranties, and the liability issues. I mean, as Valero, we are not going to sell a product that violates the warranty of the automobile of our customer. So, that issue has to be resolved before we sell E15.

E85, it has its own problems. Installing the dispensers is nearly impossible to justify unless you have a high subsidy. The 5,000 dispensers at about $100,000 each, you're talking $500 million in your base case for California. You can say, "Okay, the majors – I go to a Valero station," well, not all the Valero Stations are owned by Valero, and that's the say way, about 80 percent of the gas stations out there in the U.S. are owned by small – it's individuals that own one or two stations. There are some chunks like Kwik Fill and other distributors that have multiple stations, but a lot of these stations are owned – somebody owns one or two stations, and they make about $40,000 a year. So how do they get the money to spend $120,000? Because if it’s a retrofit, it’s going to be about $120,000 to dig up the station and put in an E85 dispenser. And then you’re going to have a problem potentially on pricing, okay?

If the ethanol is cheap enough, it makes money, too blended in a gas, or you could make money blending it into gasoline. Consumers, because of the lower mileage, want E85 – tend not to fill up Flex Fuel Vehicles unless the E85 is priced below their gasoline which generally is E10. If the ethanol is being priced close to gasoline, because that’s its value in E10, it may be priced at a point that you can’t discount the E85 enough to sell the volume through the E85 pump that you’re trying to sell, there’s just – there’s a problem there as to what is setting the ethanol price out in the market. Okay?

Next issue, cellulosic ethanol. We are aware of one – and I know their names, but I don’t want to say who it is – one 25 million gallon per year cellulosic ethanol plant that is moving forward, it is probably one to two years away. The problem is, it costs $200 million. I mean, where are we going to get the capital to build all these cellulosic ethanol plants? To date, no cellulosic RINs have been operated under the EPA RFS2 system, which – any cellulosic ethanol that was made for fuel purposes could generate RINs beginning July 1st of this year; no cellulosic RINs have been made. The demonstration plants that are out there are not selling their cellulosic ethanol for the fuel market. Okay? In the future, we expect the EPA is going to have to lower not only the cellulosic ethanol amount, but also when they have the authority to do this, the advanced biofuel, and the total renewable fuel obligation, because there isn't going to be enough either sugarcane ethanol to come in and make up to meet the advance requirement, or biodiesel out there.

Okay, RIN prices. What are they telling us? Biodiesel RINs are $1.28 a gallon. Each gallon of biodiesel generally generates 1.7 RINs, that is saying that there is not enough biodiesel out there to meet the 2011 standard. The EPA's website is showing how many RFS2 biodiesel RINs are being made in January and February, was running at a rate of about .3 or .4 billion gallons per year, and the requirement is .6 this year. Okay? So there is a possibility there is going to be an industry, in total, that is going to have to run a deficit for the biodiesel RIN obligation for the RFS2 program this year, and it’s because half of the biodiesel plants were shut down, they were small operations and they don’t have the capital to recapitalize because the biodiesel credit was taken away; on the remaining plants, a lot of them were shut down and need money for capital to recapitalize. So we just see a problem there. And the advance RINs are based on some ethanol coming in from Brazil under the Caribbean Basin Initiative and not paying the tariff, and the two-cent price for the corn RINs is just saying that the corn ethanol-based production is greater than the standard, or the requirement this year. The cellulosic RINs, like I said, there aren’t any, there are quotes out there, these are quotes, I believe, from various trade sources, and they’re not a quote of a given day, they are approximately numbers, okay? The cellulosic RINs are running $1.15 a gallon. You can go and buy a cellulosic allowance this year from the EPA when you go to fill out your compliance and it will cost you $1.13, but that cellulosic allowance can’t be used against the advance or total renewable standard where the cellulosic RIN can, but that’s telling us that the cellulosic allowance, or the cellulosic ethanol is just not out there.

Unlike – I remember being in the refinery when we had lead phase down, expanded a reformer, doubled the catalyst size, I was working on a refinery still and went from Process Engineering to P&E when PPM diesel came in, then I remember actually working with fuels regulations for RFG, the MSAT, the MSAT2 Regs, the RFS, RFS2, CARB3-3A, ULSD. All of those Regs, we could see a clear path of, “Yes, we’ll do this,” “We’ll put in this desulfurization unit at this refinery, we’ll treat these streams, or this stream, and we’ll meet the Reg.” For the RFS2, we don’t see a way to meet the RFS requirements. We don’t see how you get around the cost of the E85, and we don’t see getting around the problems of the E10 blend wall. We think Congress is going to have to go back and potentially reduce the volumes required that they put in the law and that the EPA may have to issue waivers as soon as 2011 or 2012.

VICE CHAIR BOYD: At this point, could I ask you a question about your company’s views -- and I believe this question is for anybody later on -– your views on the long term viability, I guess I want to say, of biodiesel vs. perhaps the use of renewable diesel in the future.

MR. BRAUTIGAN: I think – I’m going to have trouble answering that. I don’t know all the production economics; the problem is we don't – there's a plant in Finland, another plant in Indonesia that Neste has, and I don't know their production economics. Valero has announced that we're working on a plant to start up hopefully in the end of 2012, there will be renewable diesel, but we don't have a FAME or a Fatty Acid Methyl Ester, the traditional biodiesel plant, so I really don't know the biodiesel economics. I think the renewable diesel will be close to biodiesel in price, or to be able to match it, the problem is of not having enough feedstock. We're going to run out of waste, grease and fat, and you can make renewable diesel from soybean oil or palm oil, it's just a different processing step and you don't have to use waste, grease, and fat. So, I think both will still be there, and I think, you know, the EPA is going to set the mandate in the outer years, so we'll see what they do. Does that answer your question?

VICE CHAIR BOYD: Yeah, I think you got as close as probably most people can to the question. I guess I just have a long term concern about the worldwide demand for diesel fuel. Once economies, or most nations get back on track, I think we'll continue the developing nations' greater and greater utilization of transportation fuel, in general, but particularly diesel as they move their goods and services to the world market more and more, as they improve their economies and this, to me, is going to continue the incredible pressure on diesel supply – diesel of any and all kinds – and with diesel fuel again priced far in excess of the cost of gasoline, at least in this state of late, which is a repeat of past history. And the difficulties with biodiesel, which parallels some of the difficulties in the sense of hurdles that have been laid out with regard to ethanol, that I wonder about the long term viability of biodiesel vs. pushing harder for renewable diesel, and just pushing harder for more and more diesel to meet the demand; or, again, as I said in the earlier question, shifting to other alternative fuels in greater proportion to meet the needs of that sector of the transportation economy that heretofore has relied upon diesel fuel. Because I doubt other countries will go as fast as the alternatives in that arena has as we might have the capability or the need, so just general questions. Thanks for taking a stab at that.

MR. BRAUTIGAN: Yeah, I agree with you on the demand outlook, but renewable diesel has an advantage, you could put it at the head of the pipeline vs. the biodiesel, but I think – how big a significant portion of the worldwide diesel demand, I think we're just going to run out of feedstock for renewable diesel or biodiesel, even if we use the soybean or palm oil for renewable. LCFS, we have concerns with the LCFS also because, remember, if you met the Federal RFS, too, you wouldn't necessarily meet California's Low Carbon Fuel Standard. The LCFS is piling on, on top of that. One of the questions the CEC was asking about Brazilian ethanol, we see problems with that just as having the infrastructure to bring it all in; the problem becomes a capital one, that there's been a project, the sponsor was looking to put in a port here in Sacramento to bring in ethanol imports from Brazil, you have Gordon last year showing, "Hey, here's what you could do with ethanol from Brazil coming in," yet the market today is backwards, Brazil's is higher than the U.S., and if cellulosic – or, it really isn't "if," it's "when," that's the problem because we don't know when – when cellulosic ethanol is available, you're going to tend to use that instead of the Brazilian ethanol. So how do you get funding to beef up the infrastructure to bring in Brazil ethanol when that project may not have a 20-year lifetime, okay? We just see a lot of – we also just see it as shifting ethanol around the checkerboard, just like we're shifting crudes and we'll talk about that in the afternoon.

The cost – I know one of Gordon's slides had $1.80, $1.50 or $1.80 if the market is moving around, is about how much more a gallon of ethanol would cost if you landed it in today from Brazil. So if you had a 10 percent ethanol blend, it would cost the consumer approximately $.15 more for his final gasoline that he's putting into his car. Low CI Biofuels, "What would happen for the competition for those if the LCFS expanded in the northeast states? We're looking at a potential LCFS." We just see it, you know, the price would go up. We just see an increase in cost to consumers, more and more ethanol shuffling all around the country, and which we think is just going to raise CO_2 emissions. We don't see a big benefit of just moving ethanol from a Midwest plant because part of this is associated with wet DGS to California and bringing in a little from this planet, a little from that planet. You know, the ethanol would have been there anyway. Same thing, LCFS, we don't see a way to comply in the outer years. We're worried about meeting the percentages and that gets into – I can build a spreadsheet and I can put down a whole bunch of, "Oh, yeah, we're gonna have a whole bunch of cellulosic ethanol." But that doesn't mean it's going to come about and we're looking at not – by 2015, we think there's a good possibility that we're going to have, as an industry and as a company, have problems meeting the percent reduction standards. Remember, if you had – and some of this gets back into the assumptions, like if you're assuming not much E85, and you had E10, if you had a cellulosic ethanol at 100 percent reduction in CI, okay, say it had no CI, but it would have to be negative because the baseline is 98, but say it was zero, so you have like a 98 percent reduction in CI, that's 10 percent of your blend, so that's like 10 times 98 is 9.8, but it's only seven percent of your blend on an energy content basis, so now, you know, I'm not even going to get to the 10 percent of my blend with 100 percent cellulosic ethanol in the CARBOB, and I still have got to do something for the diesel pool. So we just see problems.

In summary, I'm not going to read through all this, like I said, it's all the regulations before we could see a clear strategy how to get there, both the RFS2 and the LCFS, we think there is some problems and a good possibility of some major road bumps where Congress and EPA for the RFS2 and CARB for the LCFS may have to revisit the programs, just because afraid of surprise implications or supply implications.

Thank you. Do you have any other questions at this time?

VICE CHAIR BOYD: Thank you. I have no further questions.

COMMISSIONER PETERMAN: I have no questions.

VICE CHAIR BOYD: Thank you very much.

MR. SCHREMP: John, this is Gordon and I just have one quick question. You mentioned that companies can now purchase from U.S. EPA cellulosic RIN credits to help with their obligation. Is there an upper limit or is U.S. EPA just making those available to the removed portion of the requirement? I mean is there some limit to how much companies can just purchase from U.S. EPA to comply with that element?

MR. BRAUTIGAN: Okay, the way it works is when we go to file our compliance for 2011, if we are – we can either run a cellulosic deficit, or we could buy a cellulosic allowance from the EPA for $1.13 for each allowance. So we know what the price is ahead of time, only obligated parties can buy them, and they can only buy them when they're doing their submission, and so you have the choice of either running a deficit and hoping to make it up in the following year for that facility because the facility can only run a deficit for one year in a row, or going ahead and writing out a check to – I think it's going to be the U.S. Treasury – for $1.13 for every cellulosic RIN you're short. The problem is the cellulosic – yeah, does that answer your question?

MR. SCHREMP: I guess my question is, can you do that indefinitely? I mean, can all the companies do that indefinitely for a billion gallons, two billion gallons, four billion gallons?

MR. BRAUTIGAN: Yeah, when they issued the cellulosic – I think the term was waiver – when they reduced the volume down – I thought it was 6.5 million this year – the Regulations state that they will also offer up to 6.5 million allowances, so, in theory, the industry as a whole could all buy cellulosic allowances and not blend one drop of cellulosic ethanol, even if cellulosic ethanol was out there and available.

MR. WENG-GUTIERREZ: So with that, we're going to move into our Refueling and Recharging Infrastructure topic. I just wanted to say a couple of words here.

In California, we have about 10,000 locations where we dispense about 20 billion gallons of transportation fuel a year. With the introduction, or increased use of renewable and alternative fuels, we're going to have to develop other types of retail station infrastructure to ensure that we have sufficient distribution throughout the state and we want to make sure that those new stations are located in strategic locations and that they are optimally used to make sure that they are successful in their venture. However, fuel supplies and vehicle populations are necessarily interrelated elements to this, and we need to make sure that, again, we are implementing the development of the infrastructure in a strategic way that optimizes the use, given our projections of vehicles and where they will be located.

So there are some challenges in trying to do that, and that would be our goal is to make sure that we try to optimize the system and have a very strategic method, but I think people should be talking about how we should go about doing that and certainly some of the questions that we had in the Addendum, or the Agenda -- the Supplemental Agenda -- speak to those. There are a number of issues that need to be addressed at the retail distribution level, some of those were discussed about E85 and the pricing, how you recover the costs for different things for the actual projects developing out there, and those should also come to light hopefully in the discussion here about retail infrastructure.

I also wanted to mention, the California Energy Commission and the Emerging Fuels and Technologies Office has an AB 118 Program. They are going to have a couple of workshops coming up, there is a May 23rd workshop, I believe, it’s the second advisory panel meeting on the Draft Investment Plan. AB 118 is a program where the Energy Commission as a whole is funding and subsidizing certain infrastructure developments. So I think there is a tie-in there, I think if there are opportunities, you know, if anybody is interested, they may want to attend that, look at the Investment Plan, and participate in that, as well. There are a couple of other workshops that are going to be presented in remote locations, as well, I think there is one in San Francisco and one in Long Beach coming up at the end of May and June, as well. So, I wanted to mention that.

I guess the next question is, is Tim Carmichael here? He is here, great. So I'm going to have Tim Carmichael come up, he'll be discussing, I think, natural gas.

VICE CHAIR BOYD: Tim, just before you start and kind of – well, go ahead with what you were – in conclusion of the last item, I just wanted to point out for those who are interested in ethanol that, in the Investment Plan, and for our AB 118 Program, we're having a very unusual experience this year in the California Legislature; oftentimes when I walk into the Offices of a Legislator, usually from a farming part of the state, I get hit with the following comment: "I hate ethanol." That trickles down to – and it's a product of the allegations that – and, you know, most of our ethanol comes from corn, therefore the allegations that the ethanol demand of the nation or this state are putting pressure on the price of corn, and thus on the price of animal feed, and thus impacting agriculture very excessively, they argue. And they have been trolling the halls of our Capitol for weeks and months now, with that message, which has put a lot of pressure on this agency's tiny little AB 118 Program that lends assistance with lots of costs, so to speak, or requirements for future progress on the aid that we have been giving to the restarting of some California corn to ethanol plants, which has a lower carbon footprint than ethanol produced in the Midwest. But the program is on the ropes, quite frankly, because of that legislative pressure and we seem to be in enough trouble with the Legislature in other arenas and areas this year that it makes it a very difficult bit of leverage, so I just wanted to pass that on to folks, this is not a hearing on ethanol or corn, but there are a lot of folks out there – we just finished a lot of discussion about ethanol, and I thought I would share our woes with you, just to know that you aren't the only ones facing issues relative to the RFS Standards and what have you – to the point that the California Secretary of Agriculture and I have had a lot of discussions about the high probability of us having a separate workshop hearing or something on the agriculture energy nexus and what it means, food vs. fuel, waste-to-fuel, etc. etc., so just to highlight that perhaps later this summer a non-IEPR-related subject, but all these issues are connected, so you can't help it but – I'm frankly getting tired of getting beat up over the fact that we put a piddling amount of money into keeping some California investment alive and running, employing California people, and returning California taxes in a few communities for a tiny amount of ethanol, instead of importing it all from the Midwest, particularly when it has a better carbon footprint; but other ramifications of that, as I indicated, are the politics of the moment. So we need to shine more light on that issue because I frankly don't know whether – because there are lots of opinions, so we're going to give lots of people a chance to express opinions on that subject. So, enough said about ethanol – more than I even intended to say, but we're all one big happy family here, so why not?

MR. WENG-GUTIERREZ: And, actually, as a follow-up comment to that, there's another workshop dealing with AB 118 where they're going to be discussing the benefits and that is part of the IEPR process, as well, so that should be – the workshop should be some time later in the summer, and the topic is the benefits associated with the Investment Plan and those dollars being invested should be incorporated into the IEPR, as well, so….

MR. CARMICHAEL: Good morning. Tim Carmichael with the California Natural Gas Vehicle Coalition. Let me just start with a shot back. I was a little disappointed in your presentation of that May 23rd workshop, the opportunity to spend all day with 20 or 25 Clean Fuel advocates doesn't excite you? I hope most of the people in the room will be there, it should be a good review of the next draft of the plan; I'm an Advisory Committee member, so plugging that meeting. Thank you very much, Commissioner Boyd, Commissioner Peterman, for the opportunity to be here and share a few thoughts on what's going on with the natural gas sector.

You know, there were a few dour comments made before me and I, actually, am going to bring a lot more positive news, I think. There's tremendous opportunity and tremendous energy in the natural gas sector right now. One example of that, there was a conference on Alternative Fuels and Alternative Fuel Vehicles in Long Beach last week. They anticipated about 800 attendees, they had 1,300, and a good chunk of them were fleet operators looking at natural gas, among other technologies and fuels, and that event included as much buzz and enthusiasm about alternative fuels as I think I’ve seen in a decade or more.

VICE CHAIR BOYD: Some of us were conspicuously absent due to an inability to travel anywhere in the state.

MR. CARMICHAEL: Well, fortunately –

VICE CHAIR BOYD: And a couple of our staff went on their own hook to that.

MR. CARMICHAEL: Indeed. It was nice to see a few State employees there on vacation. So, through the natural gas industry lands, we’re making progress every day. On the vehicle front, you’ve got every major truck manufacturer in the country producing a natural gas option, at least one, and selling vehicles today; you’ve got at least five companies building stations here in California, you’ve got now – we’re quickly approaching 150 refueling stations, public access refueling stations, in the state with, I think, just over 400 total stations, including the private fleets. And that little directory I handed out is last year’s version of the stations available for public access here in California.

That said -- oh, and I also want to say, the light duty vehicle progress has been a little bit disappointing here in California and I recently had an opportunity to talk to Commissioner Boyd about this -- Honda continues to sell vehicles, you're seeing some movement from General Motors, some movement from Ford, especially targeting the fleet markets, but not nearly the activity that those companies are enjoying in Europe and Southeast Asia and other parts of the world. So, I'm still hopeful that we're going to see, you know, considerably more models available in the light duty sector here in California in the near term. As I told a number of people in the room, I thought it would have happened by now, but I still see a tremendous potential there, especially if the projections are right, that the prices of the alternative fuels remain relatively the same of what they are today, or if petroleum prices go up even more than they have.

Putting this progress in context, though, I think is important. At this conference I attended last week, Daimler Trucks reported that in 2010 they sold – oh, and I should take a step back – I'm going to give some overview comments and then I'm going to address some of the specific questions staff gave me for today. So, Daimler Trucks in 2010 sold 975 alternative fuel trucks in the United States. This year, in the first quarter, they sold 1,000 alternative fuel trucks, so in the first quarter this year, they sold more than all the alternative fuel trucks they sold in 2010. But, they will still sell something north of 110,000 diesel trucks in the United States this year.

Peterbilt, another large truck manufacturer in the country, will sell somewhere between 220,000 and 240,000 trucks this year; they're planning for at least five percent of those to be natural gas, but they are prepared for that number to go up to as high as 20 percent of their sales this year. Jumping subjects, CEC funding, you mentioned the AB 118 program, the CEC funding in California has been tremendous. The natural gas sectors enjoyed a good chunk of the funding to date for vehicles, for infrastructure, and for biomethane development, and it has made a tremendous difference in a small, but emerging market for natural gas as a transportation fuel in California.

On the infrastructure money, there is still a struggle for our members and others that are seeking public funding from CEC for infrastructure projects. I'm talking about refueling projects, not so much the biomethane development. And the specific challenge, which Commissioner Boyd is well aware of, has been the

CEC's approach to CEQA relative to getting these funds out the door in a timely way. We greatly appreciate the efforts that have been made to streamline the vehicle funding and we're hopeful that that's going to be a tremendous success this spring and summer, and we're further hopeful that that success can roll over into infrastructure funding with a more streamlined process there.

Another challenge I want to mention with the public funding that a number of our members have experienced is, in the distribution, it's often the case that the funding is available for a short window of time, often the first couple of months of the year, which is fine if you've got projects ready to go at that time of year. But what we're starting to see is companies that, you know, get a project ready in July or August, are waiting with that project, whether it's vehicles or infrastructure, for that next cycle of funding assistance to try and seize a piece of that public funding pie.

So our suggestion on this piece, and I'll bring this up again in the AB 118 context, is it might be worth looking at a 50/50 split on funding pots, six months apart each year, in your fiscal year funding cycle, so we would continue to see a smooth flow of projects year-round. I think that's better for the industry, I think it's better for the consumers.

Public access –- one of the issues that's been coming up relative to the infrastructure funding for natural gas is to what extent should public access be a requirement. Our membership, you know, 25, almost 30 companies now operating in California, all believe that public access should be a core component of every refueling project that gets CEC funding at any significant level. You know, it's public funding going to support infrastructure that we want in this state, but public access needs to be part of those projects.

The last thing in my general comments that I want to flag is something that – actually, two more things – is that the Federal Natural Gas Act, I'm sure this is on the radar screen of many people in the room and CEC staff, but I'm not sure the Commissioners are up to speed on this, so there's been a run at this the last few years, and that's basically an incentives package at the Federal level to support natural gas vehicles and refueling infrastructure. This year, unlike years in the past, we have more than 150 co-authors on the bill, almost an event split, Republican and Democrat. That is the strongest showing this type of incentives package has seen in Congress, period. So, we are more than hopeful that there will be success this year in getting such a package through. Some highlights of this package, and then how it ties in to California. If it passes as drafted, roughly $3 billion in incentives in the form of tax credits over the next five years. The vehicle portion would cover up to 80 percent of the incremental cost of a natural gas vehicle compared to its diesel or gasoline counterpart, with hard caps on how much could be spent per vehicle, between $7,500 and $64,000, depending on the size of the vehicle.

VICE CHAIR BOYD: Tim, 80 percent of the cost? Or 80 percent of the incremental –

MR. CARMICHAEL: Incremental cost.

VICE CHAIR BOYD: -- sorry, thank you.

MR. CARMICHAEL: With a cap of $7,500 to $64,000, depending on the size of the vehicle. And then, on the infrastructure size, tax credits ranging from – actually, tax credits of up to 50 percent or $100,000 per station. And then, for home refueling, an increase in the existing program from $1,000 per home refueling unit to $2,000 per home refueling unit. Why is that relevant to California? It’s relevant to California because, today, the CEC’s 118 program is the largest all-fuels funding program in the country. If this Gas Act passes sometime this summer, it will have a tremendous impact on the near term future of natural gas and transportation fuel in this country, but it won't mean that CEC funding will no longer be necessary. What it will mean is that CEC, through the AB 118 program, will need to be strategic in the – let's say more strategic – when you've got nobody else giving funding, everywhere you give it, it's valued. When you've got a big contribution coming from the Federal Government, it's going to be more strategic for CEC to look for where the holes are and where can CEC leverage its funding, either through a matching effort with the Federal program, or cover the types of projects that the Federal Government is not going to be covering with this tax credit program.

The last thing I want to mention is a general overview of where things are going and things to watch, is that the biomethane sector, which people are increasingly calling "Renewable Natural Gas," that at a conference late last year here in California, there was an estimate that the potential for the renewable natural gas in California relative to transportation is as much as 17 or 18 percent of the heavy-duty fuel supply – 17 or 18 percent of the heavy-duty fuel supply in California. That is an important number, but it's also important to think about could that, you know, pot of gold if you will, be used more beneficially or more strategically if it were blended with fossil fuel natural gas, just looking strictly at carbon. You've got your fossil fuel natural gas, you know, 20 percent better than diesel, something in that ballpark. You've got renewable natural gas, you know, one of the cleanest if not the cleanest fuel available in the current assessment of alternative fuels; if you blend them and you get something that is 50 percent better, and you touch a third of the fleet or more in California, that may be the most impactful way to use that fuel. I'm not saying that is the only way to go, but it's definitely something that CEC should be looking at and thinking about as the biomethane market continues to develop.

To the staff's specific questions, one of the issues raised, and these kind of blend together, is the capacity of the refueling infrastructure in California today for natural gas and, you know, the fact that some of that refueling infrastructure is getting old. Believe it or not, we have been going at this, or some of the companies in the room have been going at this for more than 15 years now, and some of that infrastructure has not been upgraded yet.

As it relates to CEC, it's an issue to watch. You know, whether it's slower fueling because the compressors are small, or the pressurization is for a lower pressure than the current tanks or – oh, sorry – the tank certifications on vehicles is for a lower pressure than the new higher capacity, higher pressure, refueling stations. There are some issues with this aging infrastructure, and there is a need to upgrade, but most of our membership believes that that is something the market will take care of. The people that purchase those stations are going to upgrade them to remain competitive and, for the most part, the better use of CEC funding is for new infrastructure, to get more new stations out there, sooner.

Another question about historic patterns of purchasing and use of natural gas vehicles, and what do we see as far as future trends. The rising cost of petroleum is the number one, number two, and number three issue on my list of things to pay attention to. As long as petroleum stays somewhere in the ballpark that it is now, or goes up higher as the number of more highly paid financial analysts are predicting, the natural gas is going to be a very appealing alternative, and I'll come back to that point a couple of times.

Today, because of the price of gasoline and diesel, many fleets in the country, not just in California, but many fleets in the country, are driving less. Many fleets are taking fuel conservation much more seriously than they have in the past. A number of fleets are reporting about their driving training classes, and we actually know a couple of people that their business is training fleet truck drivers how to drive more efficiently because the price of fuel is such a factor in the operations for so many businesses these days. It’s also led a lot more fleets on a national and local scale to look at natural gas and other alternatives as a very viable alternative. I think, this year, you will see – we have seen – and it gets good attention, but maybe not enough, companies like waste management, like UPS, using natural gas and other alternative fuels increasingly, but I think you are going to see a lot more of the middle level operators and small operators do their proof of concept, their sampling, this year and the next year, bringing in two, three, five trucks, running them on a multi-month period to show not only their Management, but their truck drivers, that this is going to be a really viable option. And that is an important step towards significant purchase, whether it’s a 50-truck purchase or a 200-truck purchase over the next few years, that is going to be, I think, an area of active work for a number of fleets in California this year.

You're also seeing quite a bit of attention paid to fuel economy technologies, not just with diesel, but with natural gas, whether it is hybridization or dual fuel technologies, where you get the benefits of both fuels to maximize the efficiency, as well as the environmental benefits of the combination of fuels and technologies. One example that was given to me recently is a lot of the heavy-duty truck operators historically have averaged about five miles per gallon. But with the combination of technologies and driving skills, improved driving skills, they're upping that to seven miles a gallon. You know, when we're talking about 40 miles a gallon for some of the passenger cars, or even 50 miles a gallon, it seems like such a small number, but if you're driving 100,000 miles a year, that increment from five to seven is very significant and it's very much on the minds of fleet operators in the state.

We anticipate that overall consumption of transportation fuels is going to stay relatively low for the next couple of years assuming prices stay close to where they are today, but when the economy starts to recover more robustly, we expect a significant, if not dramatic growth, in alternative fuel use in the state. One example that I want to leave you with, again, from this conference last week, UPS's National Fleet Manager spoke at this conference and he said that he would not – he said he can see his company buying 100 percent all fuel vehicles by 2015, that is, all new vehicle purchases for UPS could be – 100 percent of them could be alternative fuel by 2015. That's less than four years away. And I think it is an important statement about how some of the largest fleets in the country are looking at the cost of petroleum, the projection for the cost of petroleum, and the need for them to make some dramatic changes in the way they run their fleets. With that, if there are any questions, I would be happy to answer them, either from you or from the staff, and then I'll see you in a couple of weeks on the AB 118 context.

VICE CHAIR BOYD: Thank you, Tim. I don't have any more questions.

COMMISSIONER PETERMAN: I don't either, although it was very interesting. Thank you for the update, and it's a bit more optimistic.

MR. WENG-GUTIERREZ: With that, I'm going to go ahead and ask Tom to come up and, actually, at this point if I could have the panelists also come up and sit at the front desk, grabbing their little name tags, that would be great. I think we have a little slide. Just, as we're getting everybody to come up, I would ask that everyone, if you have a chance, I had a slide that had some questions in there about the electricity and all the other components, as well, so we might want to look back from time to time throughout the day at the questions that we had in our addendum to, again, refresh our memories as to what we're trying to gather from the speakers today. Hopefully, again, those questions will be addressed to a certain extent in those topics.

MR. TURRENTINE: Thank you, Malachi. Thank you, Commissioner Boyd and welcome, Commissioner Peterman, and audience, thank you.

Today I'm actually going to speak for Dr. Michael Nicholas, who will be the person who really will become the PHEV Center's expert in these infrastructure issues; he is in Washington, D.C., also talking about infrastructure there.

So, the PHEV Center, thanks to the Energy Commission, is now three and a half years old, has been working on issues relative to plug-in hybrids, and now focusing also on battery electric vehicles and looking at this particular area of infrastructure; we have a team who is working on this, as I mentioned, Dr. Nicholas and two other doctoral students and researchers, and a whole group of students also working on this project. And, in the future, we'll be working closely with Ecotality in a San Diego Project, and collecting tremendous amount of data, it's an exciting time, a lot of vehicles. Just to point out some things in the picture here, most of our research over the last few years has been based on conversion vehicles. You see in the picture in the background, we have converted plug-in hybrids, we've done projects with converted Mini Coopers, working with BMW. It's a big moment, but it's an exciting moment to have brand new OEMs, vehicles coming out on the market, as we all know, Nissan, GM, and other products coming down the pike. So, we'll be working with those, but the results I talk about today are based on these conversions and research over the last two to three years.

So, just to start, this is a difficult issue in some ways. I had a chance to travel and visit a number of cities around the world and look at infrastructure for electric vehicles in the last three years, and talk to a lot of people, but we don't have any examples right now, we're in the middle of an experiment. And also, trying to build an infrastructure all at the same time raises some challenges, how do we do that? We have a lot of questions, still, you know, what's the right ratio of what we call home, workplace, and public charging, these locations. It's different than your gasoline network, you know, people as we know are going to have to have chargers at home, they could have them at any parking place, anywhere, but which parking places are the right places to put charging? Also, fast charge stations will be a little more like gas stations. How much of that network do you need? And for that market, do we think we need to accelerate the market? Is it necessarily to accelerate the market? And where do we put it, exactly? What are the details? What are the exact locations? You know, you have to cut some concrete out there and make some investments and, as you do that, you're making some commitments – is that the right place? How do you know exactly what are the right places? Do we encourage free charging? We did back in the '90s, there was a lot of free charging and dedicated spots, is this sort of an extra bonus for PEV drivers?

Do we need fast chargers? In the '90s, we didn't talk about it, now we have fast chargers, we have DC fast chargers, and in the future probably some Level 3 chargers. How important are these? How are they going to fit into our grid system, and how many might we need? They are more expensive. And what will become that right mixture of Level 1, Level 2, and fast charging? And do we need to provide chargers on our long distance corridors like I-5?

There are a lot of opinions about this right now and, as we move forward, we're in the experimental stage, it's okay to have these opinions, yet some are saying we need a ubiquitous network, we need to just put as much out there as we can, move quickly, you know, sort of a "Build it, they will buy," that this will encourage the market and move the market forward faster.

Some say Government should not be involved in this and that this should be a private sector, just let the risk develop the network, and that will be more efficient. A lot of people are talking about focusing on regional development because battery electric vehicles have a limited range and probably are not as practical on long-distance trips, so there is a focus on developing urban regional markets and not paying as much attention to rural areas. And be data driven. Plan this out. Do a better job of planning. Be careful. Monitor the use carefully.

So I'll go ahead and give the punch line, that last one, you know, being a research group, of course, we're exploiting that data-driven, we're very interested in data, and we like to use data to make decisions and design. And we're very interested in regional design, we recognize the limited range issues and have been doing a lot of work with electric vehicle drivers and plug-in hybrid drivers, we're very interested in that regional design issue.

We do see the home base as the core of the network and we use a number here, about 80 percent, but it’s more than that, probably we’ve said 90 percent, also, as the demand for electricity will come at a home base. And when I say “home base,” I mean households, but also businesses, where that vehicle is parked at night, that fixed parking spot at night, that’s where most of the demand is going to be for the electricity. Some of you say, “Well, but what about a city like San Francisco?” And I’ll talk a little bit more about that, where they don’t have as much parking fixed. We also need emergency locations, hospital, transit centers, government locations, schools, places that people need to get to, we need to have charging there.

Work place is an interesting area – how much work place charging should there be? We need ways to help businesses assess what the market will be for their employees, for their own fleets, and for visitors and clients. What will that charging need to be like? Public locations beyond work places, parking lots, shopping centers, what should it be? I talk about recreational locations in regional shopping in our work a lot. And then, fast chargers, if we bring fast chargers in, where should they go? What are the best locations? This is very much a research – we're in a research phase. We don't know, we don't have the data telling us exactly how those will be used and how much. And so we need a rigorous monitoring of this new network, it's, as I said, we're in a research phase, so we need to be monitoring just how these chargers are being used, how much they're being used, when they're being used, who is using them, we need to know this to make good decisions in the future as we roll out this infrastructure.

If you follow this data-driven approach, you have to understand the market – how is it going to develop? How many vehicles are going to roll out? We sort of know a few thousand vehicles are going to be on the road, manufacturers are going to be selling in the next few years. Who are those people? Where are they? Who has the ability to buy these vehicles? Who has a place to charge?

Here is a chart that Joshua Cunningham and I put together sort of shooting at the future, this forecasting is a difficult business, there are a lot of variables. We put together a nice – some ambiguity in the chart, but looking sort of at the low numbers here are what the ZEV program is pushing the state towards, the upper limit is what some of our hopes are for this marketplace. But, certainly, these sales as these grow will determine how this – and that mixtures of sales, how many of those are going to be battery electrics, how many of those are going to be plug-in hybrid 10’s, how many are going to be plug-in hybrid 40’s, and how will that play out in the use of infrastructure?

As I said, we expect mostly that electricity is going to come at night time from home-based, and that’s going to be more difficult than -- cities like San Francisco and Berlin are a couple we know about that are going to be trying to find places for people that to put chargers are difficult. And law will control all of that. For example, in Berlin, you can’t just put a charger on a sidewalk, it’s not legal. You can’t designate a piece of parking for somebody separate from the rest of the population, you can’t separate that out. So we see houses sort of on the left, the nice three-car garage, that’s going to the first buyers, the income, they’ve got the right place, the right electricity panel.

We just finished a big project and, in the next week we’ll be handing out the final report on this BMW project, and we’ll be having a lot to say about how people use those BMW Mini Coopers.

This is just a couple of slides from that work, to talk about. We do know that, in that project, BMW drivers did not have home charging in Los Angeles, most of them didn’t – in our interview work, we don’t ask them specifically about – we try to let them lead us in our work, and people didn’t talk about needing charging in too many places beyond home. They had a few places. And they were kind of surprising to us, when we asked them where they wanted charging, they didn’t say necessarily at shopping centers. A few people did say at work, a lot of them said favorite recreation areas and even a second home, a few people, but also ability to visit family and friends. When you’re doing transportation research, you realize that sort of travel, which is beyond the range of electric vehicles, takes you to these recreation and shopping locations.

So we’re moving forward in our research, defining charger markets sort of in three ways, sort of a primary market being those, what we call “low hanging fruit,” those households which are easy to install, that probably the income will be buying these first vehicles in the next six years. They have a fixed nighttime place the car returns to every night. The secondary markets do have a fixed place, but there’s going to be some costs involved, probably, cutting concrete, putting in conduit where a lot of the expenses are.

Tertiary markets are those which there is no fixed parking for a car at night; this is going to be difficult. How do we provide for these people? This is somewhere off in the future, but we do need to be thinking about this down the road.

Our data in the past from surveys for the United States and California and Northern California shows that about 50 percent of new car buyers probably have a good chance of putting in some sort of charging where they park their car at night, at least within 25 feet. So, some trenching, maybe. And then, work places that next priority, said this can have significant benefits, some of our research on plug-in hybrids show that you could double the utility factor or the amount of electricity that will be used by these vehicles if you put in workplace charging, so the workplace can be important if we want to reach some of our goals for using electricity instead of gasoline. Workplace charging could be used by a lot of people who visit workplaces, not just the employees and not just the fleets.

We also believe in, again, this data driven approach. We need to work with businesses to understand how this would play out and who are using those so they don’t just sit in the back in somebody’s parking lot after investment and we don’t know why they’re not being used.

Again, a regional public network. We need a safety net, we need to expand the activity space of drivers, this is the big benefit of putting in some charging from talking to electric vehicle drivers, not for PHEV drivers, really, although there is some of that, it’s to expand their activity space, not to give them charging at a shopping center that is just two miles from their home, but somewhere that allows them to expand. And fast charge may be a big solution for that, also.

Here, we look at some of the research we’re doing, just to give you the flavor of how we’re going to try to answer some of these questions. Here is just a very detailed approach to GPS travel data on 10 households, actually PHEV drivers, and looking at where they drove over a month in great detail and where they probably would charge if they used fast chargers, where would you locate those. It kind of shows you the type of research we’re doing. Here is some interesting data that, again, becomes important if we look at fast chargers networks. We can make assumptions about how they’ll be utilized, but this shows you that, you know, it’s not going to be even across the days of the week, for example, it’s not distributed – Tuesdays probably not as much as Fridays. Friday afternoon, everybody is going to want that fast charger given what we see from travel data. So, how do you build a network when you have such uneven demand?

We look at corridors. A lot of people have talked about putting in corridors in the past, we have just done a recent evaluation of Highway 99 and I-5, of course, there is a lot of population around I-99. I-5, there’s hardly anyone along it. If you did some just simple energy analysis, we’d find a Leaf, we’d need six charges driving 70 miles an hour. Actually, you could drive 55 miles an hour and you could do four charges, given that higher speeds use up all the energy, you get there at the same time. You would need to drive 55 or 70, but as most of you know, you’d probably get run over at 55 if you’re driving down I-5.

So that’s just a start, I hope that the panelists can take some of that overview and it’ll get things started.

VICE CHAIR BOYD: Thanks, Tom.

MR. WENG-GUTIERREZ: Thanks, Tom. So I think we’re just going to jump right into the Panelists, then, and we’ll hold the questions, all the questions, until after all the panelists have had a chance to speak. So I think the first Panelist is Richard Lowenthal.

MR. LOWENTHAL: Do you have some slides up there for me?

MR. WENG-GUTIERREZ: Yes.

MR. LOWENTHAL: Great. Thank you very much. I’m Richard Lowenthal. I’m the Founder and CTO of Coulomb Technologies. So, we provide software for charging networks and hardware, as well, that we use and other hardware providers use. The message of this slide, though, to me, is that we are seeing infrastructure take-up by some of the more difficult and challenging applications like the multiple dwelling unit based on having a financial model. So, that is, for instance, I just did an announcement in New York City at a 4,000-unit apartment building where they put in charging infrastructure based on sort of a vending machine mentality, that you buy this infrastructure, you charge drivers for using it, and based on that, the apartment association could justify it. So, the message being there that we need to allow capitalism to set – to have some of this growth. We appreciate our CEC AB 118 grant and that’s helped us get going here in California, but without a method of paying for ongoing costs, places like condominium associations and apartments will not put in infrastructure.

Similarly, at workplace, they don’t want open charging, they want some control, and so we see that – I’ve got some other messages about workplace, but we are quickly shifting from government subsidy to capitalism as driving the growth of infrastructure. Next slide, please.

So here, I just wanted to bring up some things, some surprises we’ve learned. We shift now 4,000 stations to over 700 customers and I just wanted to bring some news back from that world. First of all, we’re seeing PHEVs charge twice as much as BEVs, and for a lot of people, that’s a surprise. But we measure all of these things. Every person who charges on our network, we know where they charge, when they charge, how much they charge, so we’re getting a lot of data. Obviously, PHEVs, generally speaking, have smaller batteries, and so we’ve got a new term now, “gas anxiety” as opposed to “range anxiety” because they hate running on gasoline, and we’re talking primarily about Chevy Volt drivers, but they’ll do anything to stay off the gasoline, the hybrid mode of the vehicle, and so they are all charging twice a day, they are all charging at workplace and while you sleep, which is consistent with an old study of Tom’s from like 20 – well, 10 years ago – where they show that 80 percent of people want to charge twice a day of people with PHEVs. BEV drivers, on the other hand, charge a little bit less than once a day, so a very peculiar finding, and that’s because they have relatively large batteries. If they think they can make it to their next commute, sometimes they don’t charge. So, somewhat non-intuitive, but truth.

Next, we are finding – sorry, same slide – cities cannot give away electricity. Even though San Francisco announced yesterday that they will, for some period of time, they all know ultimately that it’s a gift of public funds to give away charging services, and so they will need a billing model and that will need to be enabled.

Next, we’re finding a very interesting thing in the workplace, which is that it looks as though the IRS is going to rule that giving away charging services to employees is compensation, so we’ve built now a product to measure the value of charging for employees at the workplace so that they can report that to the IRS, that’s another peculiar finding.

And, finally, I’m on a NEMA committee that we’re working somewhat diligently to get the National Electric Code to change, to require new garages that are built to require wiring for electric vehicles. About two-thirds of the cost of installation for EV infrastructure has to do with retrofit; that is, bringing the electricity to the location. And so, we are trying to eliminate that problem through the National Electric Code. That amounts to about half of the cost of the infrastructure cost now that go into the fact that these garages are not ready, so the current kind of favored thing to put in the National language -- to put in the National Electric Code -- is that you have a conduit in every garage that you build that is adequate to bringing 220 volts or 110 volts, so that you can charge a vehicle in your garage without an expensive retrofit, similarly if it’s a carport, or whatever, when you build any garage. Next slide.

Okay, so this an important one which I think I’ve heard a lot of kind of misstatements or misunderstandings about here, even at the Commission. So, charging at work, generally speaking, is off-peak. People arrive at 8:00 in the morning, they generally are charged by 9:00. I show kind of worst case here that it takes three hours. You are still always off peak when you charge at work, and so there’s a tendency of people to push away from workplace charging because they’re worried about peak charging, but, indeed, it doesn’t happen. People charge when they arrive at work in the morning and they’re always done before peak happens. Contrary, and also somewhat surprising, is that charging at home is generally on-peak, unless you have Smart Charging, so we would recommend that funding and rulings from the Energy Commission and the Public Utilities Commission, and others, require Smart Charging of some sort, so that people get off-peak when they charge, otherwise all charging will end up on-peak. And so the common knowledge is that, if you charge at home, you're always okay, but that's true as long as you wait until 7:00 or 8:00 at night. I think, in San Diego, it's 8:00 at night. In PG&E territory, it's 7:00 at night. But it is important that we don't put out too many dumb chargers, and most of the chargers that are going out now are dumb chargers, and so this problem is – we're exacerbating this problem by having bad infrastructure products going out on the market.

VICE CHAIR BOYD: So you're saying that it's a myth that the idea that we all have that people will drive home at the end of the work day, and then plug in maybe at the tail end of the peak, but really predominantly off-peak ––

MR. LOWENTHAL: Yeah, that's a myth.

VICE CHAIR BOYD: -- you're saying they're going to be plugged in during peak hours.

MR. LOWENTHAL: They'll plug-in at 5:30 or so when they get home at night. Peak ends in – in San

Diego, peak ends at 8:00. In San Francisco, peak ends at 7:00. And so they're going to be on-peak unless we do something about it. Now, the cars have timers in them, smart infrastructure has timing in, we can implement -- what I would prefer to see is that we implement time of use incentives, incentive pricing, as San Diego Gas & Electric is trialing in their territory, to encourage people to get off-peak. Clearly, if we're off-peak, it's great for the utilities, it's great for the grid, it allows us to use more clean energy, and so we recommend it, but we're concerned about the complacency that people have, that if you charge at home it's always off-peak. Next slide.

Okay, so a few things. We believe right now that the leading impediment to EV adoption is not a lack of infrastructure, although that's what you read mostly in the newspaper, it's primarily the belief that the electric vehicles are too expensive. And indeed, that is, we think, way overstated. In any analysis we do, these cars pay you back in about four years because electricity is a cheap fuel, and gasoline is an ever-increasingly expensive fuel. And so, if you look at the Leaf, it takes about two years to pay it back; if you look at the Volt, it takes, I think, three and a half years to pay back. In the next slide, we'll see the arithmetic here. Next slide.

And we're comparing the Volt to the Cruise, which is basically the same platform at Chevrolet, and the Leaf to the Versa, which are very similar platforms at Nissan, payback is very quick, over a six-year ownership of the car, the Volt pays back $8,000; the leaf pays back $7,300, and yet the only thing you'll hear in the public is that the cars are expensive. So, if we want to see people, or if we expect people to switch fuels over to electricity, we have to educate them about the low cost of operation on this fuel. Thanks very much.

VICE CHAIR BOYD: Thank you.

MR. WENG-GUTIERREZ: Thank you. So I think the next person we had on our list was Paul Heitmann.

MR. HEITMANN: Okay, thank you. My name is Paul Heitmann and I'm with Ecotality. And we're fighting the good fight, along with Coulomb. Also, one of my other hats, I'm on the New Jersey Board of – or, the Board for the Clean Cities Coalition. So, it was very interesting to hear about the natural gas because we've just implemented under a DOE grant four natural gas fueling stations in New Jersey, and are awaiting the data that we collect from that. So, it really is all about moving off of gasoline. I believe, on the electric side, the other point I’d like to make is, I was, as Richard was, participating in the MINI E Program, so it’s always nice to see data, you know, having first-hand experience in that. My particular experience involved waiting for four months to get the permit to get the level 2 charger, so I really learned what a level 1 electric vehicle lifestyle was all about.

Now, the EV project, the big project we’re running right now for the Department of Energy, I just have some handouts here on the EV project, which I will give you. And for the people in the audience, you can visit the TheEVProject.com, that’s all one word.

One of the questions that Tom raised in the presentation was what is the right mix of public and commercial charging with home charging? We do believe that most people, and I think it’s very consistent, the early findings on the difference between the PHEV like the Volt, and the full EV, is very telling, that people have a battery, they want to use it, they want to charge it. It’s almost incidental that they have the gasoline range extender. We are instrumented for a lot of data collection on the EV project and the reports that we’ve already developed with the Idaho National Labs are really geared at mining, right down to behavior differences of extended range electric vehicles like the volt and all electric vehicles like the Leaf. So, I completely agree that it's all about data collection, and instrumenting, and understanding, and then adapting as you go, which is what we're doing.

So, relative to the mix of public charging, or public accessible charging and private, we feel that there is, maybe not immediately, but very quickly after the cars are adopted, most residents, if they can, will put in Level 2 charging. And that, I believe, was 80 or 90 percent of the actual charging for the cars will happen at home. So, again, to echo Richard's comments, it's very critical that you've got the ability to defer that charging in an intelligent way, either through price signals or just straight timers, to move past that tail-end of the daily peak. Beyond that, the capability to instrument for utilities to control should include pushing a critical peak price signal because there are a couple advantages to that, 1) if there truly is an emergency situation in terms of supply of energy, the ability to override and message people that their use is going to be throttled is important, and secondly, it's starting to shift in the mindset and the behavior and response of people to be tuned into, "Hey, we're in an energy emergency, I need to do something different. At least I need to be aware that there is some difference."

So, you can have time of use rates, but that critical peak override is really the messaging that comes in and starts to change societal behavior in the long run.

You'll see on the Facts at a Glance that we are deploying – we're supporting 8,300 vehicles, 5,700 Nissan leafs, and 2,600 Chevy Volts, so that's 8,300, and when it's all implemented, we'll have 14,000 chargers. So, roughly, that's about 1.4 chargers per car. That's definitely on the high side of the public mix. Again, the experiment is really designed to see how are people going to use this, so they are all instrumented to see who uses what stations, how much of it do they really do at home, how much do they rely on the public. Most people, I think, estimate early on it will be about a 1.3 or 1.25, and over time, the more cars that are deployed, that ratio will go down to 1.1, 1.2 maybe, and it will vary by region. But the real benefit of the public charging early on is the awareness and the visibility that people will see when they're going to the showroom to make the decision, in reinforcing their decision to buy electric. So, that's an intangible value that I think, on public charging, early on is very important. And as I said, we're deploying this nation – well, 18 cities, seven states, and we're instrumented to collect quite a bit of data over the next couple years, so that will hopefully either dispel further myths, or reinforce best practices that we can leverage. Thank you.

VICE CHAIR BOYD: Well, thank you.

MR. WENG-GUTIERREZ: Thank you, Paul. Now we're going to go to Joel Pointon from SDG&E.

MR. POINTON: Good morning. I just wanted to share with you some of the highlights from the work that is going on in San Diego and some of the priority items that have evolved from that. In what we're looking at, the involvement with the Ecotality project, the involvement we have with the Multi-Unit Dwelling Outreach Program, we have existing EV Time of Use rates, which occurred back in the '90s. I have to say that the major challenge that we have facing us is the educational aspect with the stakeholders, the community, the public at large. And that's why you'll see that, in this lower section, it's the education portion that is critical. One of the things we do in every presentation that we do is we try to get people on the same page by giving them a basic vocabulary, giving them a glossary so that, when we use these terms, we at least are all on the same page, they have some appreciation for AC charging vs. DC charging, and some of the impacts that that has.

Getting the message across about the importance of the off-peak charging and whether we utilize off-peak charging will be the success or the failure for these vehicles, going forward. Our Ecotality project has been going through some revisions. At the latest revision, we're at 1,000 for a target for residential installations, 150 to 250 volt installations, still at 1,450 of the public access Level 2, approximately 60 of the DC, and we have just recently added workplace charging as the component. This is the only Ecotality project in the country at this point that presently has workplace charging added to its mix.

Getting the messages across about our EV TOU rates is another challenge. We have separate metering, we have whole house, getting the consumer to appreciate the differences between those two can be a major hurdle and we put a lot of time and energy – this is some of the pictorial representation that we are trying to use to get that message across to the consumer easily, utilizing our website as the back-up for this, so that they can get more detail. And we do individual consultations over the phone for rate analyses.

I'm going to skip this, only to say that there is a broad spectrum of projects that we're working on, the one that I'm most involved with right now is the last one, the Multi-Unit Dwelling Outreach Program. We did a presentation yesterday to the Southern California Section of the California Association of Community Managers, which are the people that do the property management for and will be facing the many challenges. And we heard loud and clear from them yesterday, that they are feeling a bit overwhelmed with the challenges. Here is a pictorial representation. You live in one location, your meter is in another location, your parking in a separate location, trying to bring those threads together within a community, as well as the physical limitations that we have in some of these facilities. This is an example of a high-rise condominium and the type of metering configurations that we're seeing. So, in those instances, dealing with the legalities that they're dealing with, dealing with the metering and wiring, and dealing with the cost allocation to their residents, everything from the non-communicating infrastructure equipment to something as advanced as can do individualized billing and recognition of customer use, and getting them to appreciate all of the options that they're looking at.

We're going to be rolling out next month our Multi-Unit Dwelling Workshop Program. We will be providing PEV 101, which is a basic orientation for everyone in the room, and then inviting property managers, homeowner association presidents, and vehicle owners to present to others and to give their story as to how they've worked through these issues, and we have a checklist that we are providing to multi-unit dwellings to help them work through these issues. We're heavily pushing the Goelectricdrive.com resource, which is a national website developed under EDTA, as well as our own localized web source.

Again, I'm just going to stress that, in addition to our metering challenges, or notification challenges, education is where most of the attention is being placed at this point and getting the word out through our website, working – we're doing training of personnel at the dealerships, we're doing training directly with the contractors and inspectors that are doing the work in the field, and again, as I mentioned, the outreach training program. And we have multiple ways for them to communicate with us and to send us their questions and to monitor what we're doing going forward. And thank you. I appreciate it.

VICE CHAIR BOYD: Thank you.

MR. WENG-GUTIERREZ: Thank you, Joel. Next, we'll have Russell Vare speaking.

MR. VARE: Hi, good morning. I'm Russell Vare with Nissan North America and I have a couple slides that you can feel free to scroll through for me.

I wanted to give the automaker perspective on infrastructures, and thanks for the opportunity to speak. If you go to the next slide, that's really just for reference, it is product details on the Leaf that I don't need to go over. So, if you go to the next slide, to give you an update on our launch, we have an increasing amount of interest in the Leaf, more hand raisers are registering with the website. Out of our 20,000 initial reservations, we started delivering in seven states, including California, and have had over 1,000 deliveries so far within North America, and we reopened reservations for those seven states May 1st, so we're going to see that 20,000 number increase shortly, so glad to see more cars getting on the road. And out of that early number of drivers, we have some early data if you go to the next slide, I kind of take this with a grain of salt because it's only a few hundred drivers over a short period, but we are kind of basically seeing the electric vehicle drivers are doing as expected, short trips, at home, recharging at home, seven mile average trip length, most people are charging Level 2 at home, and the average charge time is two hours and 11 minutes so it's pretty much what we expected, and we expect most charging to be that kind of bottom part of the pyramid that we talked about, where it’s at home, and it’s at night, and it’s off-peak, and we’re starting to see a glimpse of that’s what it’s going to be. You know, I would wait to see more data from EV Project and from the other studies that are going on to have a more robust look at it, but we are getting a lot of customer inquiries on public charging – where is it going to be, how much, how do I have access to it. So, if you go to the next slide, what we tried to show our customers is that this is what we have visibility to; we see kind of 11,000 to 12,000 Level 2 and DC fast charging stations going in around the country so far. You know, we base this on Level 2 or DC fast charge, publicly accessible, and J1772 plugs. So it’s looking really really good for California in terms of the number of public charging – I think 4,000 to 5,000 is kind of what we see in the major metro areas, which is really good for, I think, building the market since there is customer demand and customer interest in having public charging.

You know, there are a lot of questions that focus on the number of stations and, you know, making sure they’re fully utilized, and what time they’re used, but if you go to the next slide, I think what we need to focus on is whether it’s customer-friendly. And, in terms of volume, what we're looking at, if you look at Tom Turrentine's slide from earlier, the volume for California is still going to be in the tens of thousands for the next few years, which is not necessarily going to be kind of a huge impact on the Grid in terms of they're charging during the day, and having a public and workplace charging that the customer uses, likes, wants, is really going to help build this market. So, you know, I think what we want to do is make sure we build the market for electric vehicles where all these questions about infrastructure become moot if there's not enough cars on the road to use them. So, if we do have a public infrastructure that's well-used, that will probably help work in to these other challenges that we have with multi-family dwellings and garage-free homes, that they have confidence they can use public charging or use workplace charging that has well-designed policies around it.

And one example I have, there is the EV Go Network, that's a model in Dallas and it's in Texas with NRG funding it, and they have the public network of Level 2 and DC Fast Charging that you pay a monthly subscription to, so it's just one way to look at it. And, of course, Ecotality and Coulomb have their models through looking to make it convenient to the customers.

I think that that should be kind of the most important question as we look at the early market.

And then, of course, as we look at the long term market, following up on what Richard Lowenthal said about pre-wiring homes and parking garages, as we look out kind of 2020, what's going to be the easiest and cheapest way to expand infrastructure, and it's going to be if we look at pre-wiring homes for today. But those are updates from Nissan, thanks.

VICE CHAIR BOYD: Thanks to you, Russell.

MR. WENG-GUTIERREZ: Thanks, Russell. And then the last panelist is Dan Bowermaster from PG&E.

MR. BOWERMASTER: Good morning. So, I didn't prepare any slides and, if I did, they would be largely repetitive, like you've already heard. We definitely agree with what you heard as far as we need data. Everyone has an opinion, and everyone has a forecast, and in PG&E's territory, we project by 2020 there will be between 220,000 and 850,000, and really, the key inflection point, which we saw in Tom's slides, was the 2014-2015 timeframe, so one of our challenges is, and here is the focus, is how do you support the market now while designing programs and services and policies that help bridge that gap in between the early adopters and the mass market. And I guess, you know, some of the things – you heard Joel mention a lot about utility work that is going on right now, the five big utilities in California, the three IOUs plus SMUD and LADWP are working quite closely to align the customer experience as closely as possible. Now, granted, everyone's reality is slightly different and we all work with the car companies and the service providers, so every flavor is quite a bit different, but the big thing that the utilities have control over is rates. And one bit of data that hasn't been brought up yet is the second meter. It was mentioned how expensive to install the second meter can be, and that can range from $500.00 all the way up to – we've seen installation costs in the $12,000 range for a second meter. And, so far, the data size is still statistically insignificant, but historically, in the mid '90s, we had roughly eight percent of our customers, electric vehicle customers who chose the electric vehicle rate, choose the second meter. Right now, we're seeing it's about 20-25 percent, which isn't surprising if you think about the profile of the early adopter also having solar, it makes a lot of sense to keep your solar rate on your house and then have the electric vehicle rate on that second meter. But it's important, and something Joel and other people have mentioned, education. How do we educate customers up front so they know what, first of all, their options are as far as electric vehicle rates and choose whichever one fits their profile. And, secondly, if they do choose a second meter, what might the range of costs be? Because we'd hate to have a bad customer experience, I think, and all of us around the table can agree that, where a customer almost blindly chooses to put in a second meter, only to get half-way down the path and find out it's thousands of dollars to put in a second meter.

So, I guess, to close, I would rather keep this short so we can open up to questions because I think that's the most beneficial. So, we are focusing on the customer, working closely with all the stakeholders, and so far we really see that it depends on the use case, you know, San Francisco, as Tom mentioned, is quite different than, say, a Stockton or a Berlin, for that – well, not Berlin – but Stockton or Sacramento. So the solution there might be different and there might be other solutions in conjunction with public charging or workplace charging, maybe car sharing will play a bigger role and maybe there's a way there to support the monies in that direction. I think we collectively need to think creatively. I mean, every MUD is different and every customer is different, and it's really important, I think, that we figure out solutions and that we don't generalize one or the other. Granted, a lot of customers who live in a nice three-car garage house can charge off-peak overnight at home, which is what we want, or even at work in the morning before, say, 1:00 or 2:00. But the customer who lives in a high-rise in San Diego or San Francisco is going to have a very different need. Thank you.

VICE CHAIR BOYD: Thank you.

MR. WENG-GUTIERREZ: Thank you. So if there are any questions for any of the panelists or from –

VICE CHAIR BOYD: I have no questions. Are you entertaining questions from folks in the audience?

MR. WENG-GUTIERREZ: Sure, yeah, anyone.

VICE CHAIR BOYD: This is a workshop, not a hearing.

MR. WENG-GUTIERREZ: Okay, it looks like – do you have a question? Go ahead and come up to the podium and identify yourself.

MR. MACCURDY: My name is Dwight MacCurdy. I work with SMUD in the EV Department. I'm curious about the availability of the data that will flow under the Federal Grants, when it will become available to all of us, when we'll be able to utilize it, and from the car companies, not only from the EVSP suppliers, but the car companies.

MR. LOWENTHAL: I can answer that for Coulomb. We are already sending data to the Idaho National Lab, and we would be happy to share that data with you, too. It is available, so if you just contact us, we can get that data to you. For Idaho National Labs, we are tracking for everybody that charges where they charge, how much they charge, and when they charge, so we're happy to share that – well, the taxpayers are paying for it, so we're happy to share it with anybody that wants it.

MR. HEITMANN: Yeah, we have – the project has obligations for reporting quarterly, and we've worked through the template, we've shared that with all of our participating partner utilities in the regions under the EV project, and we've also developed a customized per utility variant of that report, so once that data is collected and put together, it's going to flow out in these vetted report formats. I have an example here, I didn't put it up on the slide, but if you'd like, come and look at it, or we could put it in as a, you know, formal exhibit. As I mentioned, it's pretty detailed, it'll look at Volt vs. Leaf use and in different contexts of public vs. overnight charging, average ranges, those type of things. But it's very important that we keep the privacy of the individual users intact, so the data really, by design, was done in an aggregate form, but the value of it is there, you know, to see those type of trends.

MR. VARE: And Nissan data will be available through the Quarterly Annual Reports.

MR. HEITMANN: Yeah, one aspect of that, too, I think, we've been working again with – the utilities have a very vested interest, I guess, in getting heads up on where these cars are coming and I know Nissan and some of the other OEM's have been working with the utilities and we have, too, to where we can give people heads up so that they can do some planning, infrastructure impact planning, because it is a very real possibility that you could get clusters of several vehicles in one place and having a heads up on that is important for utilities.

MR. WENG-GUTIERREZ: I guess, to follow-up on that item, one of the questions that I jotted down was, if you could speak to the collaborative efforts that are occurring and what type of collaborative activities do you have between your different like OEM, utilities, local agencies? I mean, is it being overseen by certain agencies? Is the PVEC Collaborative pivotal to that? Are there other agencies or other mechanisms for communicating these things?

MR. POINTON: I think if I were to cite one particular forum that, for us, has been most efficient, most supportive, for gathering data, it has been through the EPRI Infrastructure Working Council, which actually brings together the automakers, the EVSPs, the utilities, as well as the supply chain providers. And it gives us an early indication of where trends are going. We're going to be seeing these vehicles coming to market. They're already here, they're at 3.3 kilowatt load on it. We're going to see vehicles going to 6.6 by the end of this year and there's a disturbing trend among automakers to discuss going to 19.2 for residential, which is not a sustainable situation for utilities. They're looking at this for both the upper and AC Level 2's, as well as DC Level 1, they're proposing three levels for DC charging, as well. So these are trends that we need to monitor early, we need to offer feedback on, and from our point of view, the EPRI Infrastructure Working Council, working with SAE on Standards setting, has been the forum where we get the most bang for the buck.

MR. VARE: I would say the PEV Collaborative – California PEV Collaborative is a good place for a lot of this, working together on issues, and there's even several topics that are very specific like the NREL, GOE EVSE database, looking at infrastructure mapping, and so there is depending on the topic, there's different groups working together.

And it looks like we have another question.

MR. HEITMANN: One last point. I guess part of our EV project method, deploying in those 18 cities, we start with what we call a microclimate assessment and it really is meant to have a framework for people to come around and collaborate on, and the first benefit of all that is building those stakeholder alignment, so utilities are key players in that, as well as Council of Governments, and other folks that are centered around that region. And that's a very important first step just to get everybody literally on the same page, not that it's not without contention, but it definitely gets people moving forward towards that first important step of agreeing, "Yeah, here's where we want to build the infrastructure."

MR. WENG-GUTIERREZ: Great. It looks like we have a question.

MS. GREY: Gina Grey with WSPA. I think we have two electric utilities on the panel if I'm not mistaken, and we in the auto industry would be interested in any comments that you have to provide on, first of all, whether or not you are anticipating opting into the Low Carbon Fuel Standard Program and, if not, I think we would like to hear why not; and, if you are, any projections on the volume of those credits and projected costs of those credits that the oil industry would have to purchase? Thank you.

MR. POINTON: I can only say that it’s still under review. Internally, I don’t have a statement to make relative to that.

MR. BOWERMASTER: Yeah, we’re still – PG&E is still evaluating LCFS, as well.

MR. WENG-GUTIERREZ: And I think there is an LCFS working group, which is talking about these issues and who would be getting the credits, and how it would be accrued, so it is certainly still part of the – you know, still being developed right now, but any insights that you have, I’m sure everybody would like a piece of the pie, but any insights would be appreciated.

MS. GREY: In particular, since the program began January 1st of this year.

MR. WENG-GUTIERREZ: Sure, absolutely.

MR. HEITMANN: I would use that as maybe an opportunity to – it’s all about people being aware of their impact, or mitigation of impact on carbon, so one of the things we’ve done is really to extend our network to include things like a home energy controller that allow people to track and access and monitor those things, so as credits become more sort of tangible or fungible, right now, it basically measures or present displaced carbon based on how much you're using your electric vehicle, but as things like economic credits get tied to that, it's a perfect place to bring that in a consolidated way, so people understand what the whole picture is of their use of electric vehicles.

MR. WENG-GUTIERREZ: Okay, and then I think – were there any other questions from anyone? All right, then I guess, with that, we'll go ahead and move on to the next set of presenters. Thank you very much.

VICE CHAIR BOYD: Thank you, Panelists.

MR. WENG-GUTIERREZ: So, next we have Steve Eckhardt from Linde. It looks like he hasn't called in, so can we go with Ed Heydorn from Air Products?

MR. HEYDORN: Thank you. Good morning. I'm Ed Heydorn from Air Products. Thank you, Commissioner Boyd and to staff for the invitation to speak today about questions related to hydrogen infrastructure, the needs, and the impact on the report that will be generated by staff in the fall. So, I'll just give a brief overview talking about the supply chain for hydrogen because that's going to influence the needs of the stations and the requirements for infrastructure, going forward, through production and distribution and up to the point of dispensing. That will get into station deployment strategies as to how you can best manage infrastructure during this roll-out of fuel cell vehicles. Some of the automakers have shared some vehicle information in response to questions from staff that I'll provide some information on, and then talk about other issues that were raised in the questionnaire that we were asked dealing with quality and Codes and Standards.

This is a slide I've used in a number of presentations to talk about the variety of pathways for production of hydrogen, either central production with distribution via pipeline, if you produce liquid hydrogen, that mode of distribution, you can also dispense compressed gas for those needs, and even down to selling requirements for very small users. And there's also distributive production, where the hydrogen is produced at the point of use from a variety of feedstocks. It's one of the beauties of hydrogen and one of the challenges is that you can make it from a variety of pathways, and it's really managing the supply chain that is the key. So, this is another slide talking about different modes of supply and how they kind of fit in terms of the overall economics. And it ties into a variety of factors, including distribution distances and electricity and diesel cost, as well as volumes.

So, hydrogen really is a volume business and low cost central production can meet requirements today for transportation. We supply hydrogen into the refining industry at large volumes, and that is incorporated into the price of transportation fuels. There was an NREL study recently that showed hydrogen cost of production is $1.33 per kilogram at large volumes, so that’s really just the front end of the supply chain, but it does show that there is a pathway to produce hydrogen at very low cost today.

Yesterday, we participated in the opening of a hydrogen fueling station in Torrance that’s directly fed from an Air Products industrial pipeline that serves the refining industry. That station provides a – what I look at as more of a future pathway to supply hydrogen when there are a significantly large number of vehicles, but today you have to approach things in a different tact in order to successfully roll out infrastructure.

So this is really the current supply chain for hydrogen associated with vehicle fueling, starting from the point of production through distribution, storage on-site, and then preparation for fueling and, finally, dispensing to the car. Now, the key is really to find an approach to distribute low cost hydrogen from central production facilities to points of use, and California is fortunate that there is excess hydrogen capacity from various suppliers, including Air Products, and so there are ways to utilize that capacity without at this phase of infrastructure development to invest in new production methods, that those can wait until more vehicles are in place. So that investment doesn’t need to be made today to support vehicle infrastructure.

Now, in terms of station considerations, kind of the easy part of the solution is that we can build stations now for very large through-puts, for example, for material handling, or mass transit projects. Those are projects that are ongoing and that are done – one example is with liquid hydrogen with liquid compression, with redundancy for the compression steps and multiple dispensers to serve the number of users for these sites.

But there are issues for going to the large station today for light-duty vehicles. It extends the time where the utilization is low; if you have to put in a very large station, it will take longer time to get that station up to full utilization and into its best capital point. Also, footprint. For gasoline stations where we’re seeking to install refueling stations, how many of them are really amenable to these larger footprint requirements? And is that really needed today, given the strategies for roll-out of vehicles? And also, depending on the type of infrastructure you invest in, you could have those assets potentially under-utilized by future innovations. The people in the supply chain for hydrogen are continuing to look at new ways to produce, distribute, and dispense hydrogen, and there's also innovations on the vehicle side that continue to be made. So, it's best not to over-invest, in my view, in an infrastructure that make it outmoded over a relatively short period of time.

This is a map of stations that were selected by the Energy Commission under the aforementioned AB 118 Program. It's the beginnings of a network in Southern California that the idea is to try and build the stations at the points of use where the automakers are providing input to the Commission, and to infrastructure providers, to say these are the best early markets where vehicles are going to be deployed.

The challenge and the opportunity for the fuel cell vehicle is the fact that they have such extended range, it's not reasonable to try and have them tethered to a particular station. So, the strategy that the automakers are proposing and that we're trying to serve into is the idea of providing a coverage area within the early markets, is to meet the needs of the consumers, to be able to drive where they want to, and not be benchmarked to a particular station. I mean, you could build one 2,000 kilogram a day station and that could provide enough capacity to be able to satisfy those needs of the vehicle market, but, as we all know, we like to drive different places, different times, and as I said, be un-tethered.

So, as you look at infrastructure, if you look at the infrastructure investment, there are different ways you could approach it in terms of the number of stations, depending on the amount of investment that's needed for those. And so, in order to try and meet these coverage needs, that the automakers and their customers are seeking, we're looking to try and serve those markets utilizing modeling tools. There's a recent development from the folks at the University of California Irvine who is, I believe, under contract with the Energy Commission that looks at siting methodologies for fueling stations, not just for hydrogen, but for other fuels. And so, using these type of modeling tools combined with the market data from the auto makers, can help target infrastructure deployment so that investments are made at the right point and to the right level where it’s not over-investing. So this would help support the development of the clusters, which automakers have talked about for a number of years as a key approach to start the market, and then also considering destination stations and, again, you know, the question is do you want to put a $3 million investment at a station that’s going to be lightly used for a long enough period of time until it becomes a cluster in the future.

So the solution that we are developing and installing at the stations under the initial AB 118 award is looking to drive station costs down to $1 million or less, and what it does is it accomplishes that by reducing the amount of infrastructure needed at the forecourt and centralizing that at the point of production instead of the point of use. It allows for ease of expansion and it also allows the market to determine when a station is expanded, so it’s not, again, over-investing today until the market is more fully developed.

Now, we have submitted information to the docket for the 2011-2012 AB 118 Investment Plan, it talks about hydrogen pricing for this type of station model, and we show that the pricing is attractive for transportation and these are stations, you know, 300-500 kilograms a day, so they are not the super large stations that were thought of in the past. One of the questions that we were asked for is about tax structure, but with this type of fuel pricing, $7.00 a kilogram untaxed, you could certainly operate in the tax structure as you do with other transportation fuels.

One of the opportunities and challenges that we're looking at with the various stakeholders is how you deal with fixed operating costs of the stations during the time before vehicles come out in large enough numbers to fully utilize the station, things like insurance and property tax that a station owner will have to incur, even if he doesn't sell one drop of hydrogen.

These are numbers that have been developed through surveys from the California Fuel Cell Partnership, which I know the Commission is very familiar with. It talks about how the transition will roll from hundreds to thousands in the 2015 to 2017 timeframe, tens of thousands of vehicles. And in the bottom left there are some operating results to date from the vehicle and bus programs that have been undertaken.

With regards to the pricing, this is a chart that Toyota has provided and I think they shared in other venues, that talk about cost of vehicles as a function of driving range, looking at fuel cell vehicles being fairly well developed in their minds, in terms of cost structure, with the increase in cost really just based on the amount of additional storage that's needed on board the vehicle to get the additional range.

So, fuel cell systems and mass production in many of the OEM's minds is an attractive pathway to meet vehicle owner needs for range and convenience of fueling. And we were asked to talk about hydrogen quality and issues that we see going forward. As I mentioned before, hydrogen could be made from a variety of sources, both from dedicated production plants, and also byproducts from other chemical production facilities. There is a Standards evolution going on for hydrogen for vehicle fueling, there are certain components that are more difficult to separate from purification standpoint. These type of specifications could disqualify certain feedstocks from being amenable for fuel cell application, so that's something that we're working through in terms of the development of the standards. Some of them are still – some of these standards that are being proposed, there have to be measurement techniques associated with those, they're not altogether proven yet, so in that world, there are a series of round robin testing that has been proposed to be able to validate the standards, so that we can, as a supplier, in order to meet quality control requirements, we have to be able to get the performance of the standard, the degree of accuracy, and then put in our quality control measures to be able to understand where our production point needs to be to meet those requirements.

Now, in terms of any of these test methods, it always ends up adding costs for analyzers that would be installed and just operation and maintenance, just validating analyzers. I mentioned about confirmation of the test methods and one of the things to consider about analysis within the supply chain is it is obviously easier to do at a large central facility than in a distributed production method, that is one of the hidden costs of hydrogen from a distributed method vs. centralized, because now you're going to have to have distributed analytical capabilities at all the points of use.

And today, hydrogen is already made at ultra high purity, so there are costs just associated with recoveries, I mean, we provide hydrogen to the electronics industry of very high purity, and the question is how far do the standards need to go from the vehicle side in order to make the overall proposition work. It’s a question of balancing out the needs on the fuel cell vs. the availability to produce and validate the hydrogen that is being produced.

It’s also asked about other Codes and Standards topics, Air Products participates in organizations that develop Codes and Standards; one of the things we see, not just in California, but in other parts of the country is, depending on the local rules, the authorities having jurisdictions have different interpretations of the Codes, and that leads a lot of times to different results at different locations for the same hardware, so that becomes a challenge for the speed to be able to roll infrastructure out. And what we’re trying to do with our system within the eight station deployment under the AB 118 program is to standardize that kit, essentially, so that we can roll out the same equipment at all the sites so that there is a certainty from a permitting standpoint, and obviously from an operation and maintenance view, as well.

With the smaller stations, because there are more options to do, waste to produce or distribute and provide the hydrogen, you end up with hundreds or even thousands of configurations. So the fact that the stations are starting to get larger, it starts narrowing down the options for the hydrogen that's going into the forecourt, which will hopefully simplify the permitting aspects of it, and as I mentioned, stations getting large or the options will be less.

One other topic that I didn't put on the slide, there was a question on hydrogen metering and the work that the CEC is sponsoring with the Department of Food and Agriculture, we continue to support those efforts to look for a solution to be able to achieve unit pricing at the point of sale for hydrogen. We see it as a solvable problem, it's like a lot of the components within the hydrogen industry, volume will help take care of a lot of it to incent the makers of instrumentation to be able to come up with a solution, to be able to provide accurate measurement from very low pressures up to the 700 bar levels that the vehicles currently require, but we continue to support those efforts and the efforts within the state to try and promote those solutions. So, again, I thank you for your time and for the invitation, and I don't know if I can take questions now, or if that's later in the program?

MR. ECKHARDT: Good morning. Can you hear me?

VICE CHAIR BOYD: We can, thank you.

MR. ECKHARDT: All right, good morning. Well, my name is Steve Eckhardt, I lead Linde's Business

Development activities for Hydrogen Fueling and we'd just like to thank the Energy Commission for inviting Linde to present here today.

Linde is a $15 billion multi-national gasses and engineering company and we supply hydrogen, oxygen, nitrogen, and many other gasses to a multitude of industries. Can we move on to the next slide?

By the end of 2012, we'll have supplied no fewer than six hydrogen fueling stations in California. Of these, we are currently building three fueling stations for AC Transit. Two of these stations are for their fleet of fuel cell busses, and one is for light-duty fueling of vehicles. Both the CEC and the ARB awarded funding to AC Transit for these stations and that leveraged a significant amount of funding that was provided by the Federal Government, as well, for those installations. In addition to that, Linde was recently awarded for three car fueling stations from the Energy Commission, with recently here in 2010, and those will be located at San Francisco Airport, West Sacramento, and Laguna Niguel. We expect all those will be operational next year, and these will represent the highest throughput hydrogen fueling stations in the country and they're fully compliant with all industry specs for fast fueling.

If you look at the bottom of this sheet, fuel cell vehicles offer California a vehicle with zero tailpipe emissions, vehicles that are running on domestically produced fuel, vehicles that reduce carbon emissions by 40 percent or more, depending on the source of the fuel, and based on the public announcements by the car companies, these cars will be priced competitively starting in 2015, with conventional hybrid vehicles. We believe these vehicles are a critical component of the State’s plan to meet the goal of 80 percent carbon reduction by 2050. Next slide.

I think it’s important for a few minutes just to talk about what is happening around the world with fuel cell vehicles and hydrogen fueling, so if you look at the top slide, in Germany, a consortium of industry and government, which is called H2 Mobility, has defined detailed plans for the deployment of about a thousand stations in Germany by 2017. In Japan and in Korea, there have been recent announcements, as well, for the deployment of hundreds of stations.

We have worked with the car companies for many years in supplying hydrogen, supplying hydrogen fueling stations for these vehicles, and then developing the industry standards for hydrogen fueling. And through our partnership with the car companies, we’ve learned much about the vehicles and the commitment of the industry to deploy them. We believe these cars will be deployed and, hence, we are investing significant dollars into research, development, and deployment of hydrogen fueling technologies around the world.

Right now, we believe the only unanswered question is where the vehicles will be deployed. Linde strongly believes that California is one of the key places for fuel cell vehicles to be initially deployed, and if industry and government work closely together in rolling out the infrastructure required, we are confident California will track many thousands of fuel cell vehicles. But it's important to remember, this is indeed a competition and it is important we recognize that we must develop an infrastructure that can properly fuel these vehicles and offer a superior value proposition for the drivers. While these steps won't be easy, we think they're definitely achievable, and will ensure fuel cell vehicles are soon on California roads and highways as an important step in the emissions reductions plan.

Now, in California, I think we're off to a good start. With CARB funding, about $14 million in 2008 and 2009, for seven car stations, and then the recent Energy Commission funding of over $15 million for 11 car stations in 2010. The funding for these stations will allow industry to deploy public fueling stations that we hope will exceed drivers' expectations.

As I indicated before, Linde is supplying four of these stations for auto fueling in Northern and Southern California, and we appreciate that the Energy Commission recognized our technology, our business model, and our partners for the award of these grants for the stations.

Linde will be supplying hydrogen to these sites mainly through delivery of liquid hydrogen, but also from an electrolyzer supplied by Proton Energy Systems. In addition, Linde can supply hydrogen from sources located in Chicago, as far away as Quebec, even, and I think it's important to note that our hydrogen plant in Quebec is supplied by a Sodium Chloride plant, which actually uses water as a feedstock. We then take that byproduct, hydrogen, and use green hydroelectric power and produce what is a 97 percent renewable hydrogen. And I think this goes to show that it is possible to produce renewable green hydrogen and it can be done anywhere or in many places in North America.

In addition, hydrogen can be produced by electrolysis of water and the main way right now is the reformation of natural gas or renewable biogas. Most of the hydrogen available today, as I said, is produced from the reformation of natural gas and this process can be done both at a central hydrogen production facility, or on-site if the demand is sufficiently large, and I'll talk a little bit more about that in a few minutes. Next slide.

So liquid and compressed delivered hydrogen to the site is likely going to be the predominant supply for the next several years due to the economics and due to the demand levels at each station site. It's important that we appreciate the cost of delivered hydrogen is competitive with gasoline today, based on vehicle miles driven per unit of energy, and it offers really what I think is an outstanding value proposition: switch from an imported fuel which produces emissions at the tailpipe, to a fuel that is domestically produced, can be renewable, and emits only water vapor at the tailpipe, and is about the same cost as gasoline.

Now, in the future, when hydrogen demand by fuel cell vehicles outstrips the current supply, new centrally located hydrogen production facilities will be built, which will be larger than the current plants. These larger production plants will bring economies of scale and improved energy efficiency. And when hydrogen demand in a single fueling station is on the order of

200 fuelings per day, on-site production of hydrogen will be a viable option. The cost of hydrogen fuel produced on-site can produce cost savings compared to delivered hydrogen, and another benefit is that this option does not rely on frequent deliveries of hydrogen to the site.

So, in summary, it is our view that hydrogen can be produced cost competitively compared with conventional gasoline, and it offers a superior value proposition for fuel cell drivers in the State of California. As I’ve noted here, it eliminates tailpipe emissions, provides a significant reduction in well to wheel carbon emissions, it is a domestically produced fuel, which reduces dependence on foreign oil, and it can be produced from renewable sources. Next slide, please.

So, with respect to hydrogen fueling infrastructure, I’ll spend a few minutes talking about this, we built over 70 hydrogen fueling stations around the world and have significant experience with a number of different technologies. We can compress hydrogen in a 900 bar, which is well over 10,000 PSI, and that’s sufficient, then, for fueling a 700 bar vehicle quickly and, back to back, offering the driver with an experience similar to that of conventional fueling.

Linde believes the number of stations required to meet the needs of fuel cell drivers should consider a number of factors, which are listed here on the bottom slide, and those include the number of fueling points by geographic area. Now, this will ensure that we have good local coverage, or good neighborhood coverage where somebody lives. Second, considering hourly peak fueling capability to ensure continuous back to back fueling capability during rush hours. During rush hour is when many people are going to fuel and we need to make sure that the capacity is available for people to show up at the sites during rush hour and not have to wait for a dispenser. And finally, the daily fueling capacity is important to understand long term what the capability of a station would be. It should be noted the industry has indicated on the order of 40 stations should be operational by 2015 to ensure drivers' needs are met. Next slide, please.

The other item we think is important to comment on is that we need to show stakeholders, government, car makers, oil companies, and investors, that the technology exists to fuel many cars at a site, at the lowest possible cost. These types of stations are the ones that will attract the investors with the lowest cost per kilogram dispensed and will drive the industry to expand on its own in the future without government funding. In addition, these stations will be necessary to fuel the large numbers of vehicles scheduled to be on the road starting in 2015, when car companies begin to sell these cars to consumers in the thousands. And it is incumbent on the fueling infrastructure suppliers to prove this can be done.

On the bottom slide, you can see there kind of a summary or an example of the types of stations that can be deployed. If we consider that there could be about 10,000 vehicles on the road in 2015, which would be on the way to what the car companies have projected, 53,000 in 2017, the hydrogen fueling infrastructure must be capable of dispensing about 10,000 kilograms a day of hydrogen, assuming 1 kilogram a day per car of consumption. The proposed combination is 150 kilogram per day stations and 750 kilogram per day stations, and this allows all these drivers with the ability to fuel at any one of these 40 stations. Now, the assumptions on an example like this certainly can be tweaked, and they should be debated. The mix of stations can be changed, the size of the stations may be different, and capacity utilization of the stations may be higher or lower, but the end result, Linde believes, is quite clear: by 2015, the industry will require on the order of 40 stations and a healthy proportion of these stations must be high throughput stations. As I noted before, the stakeholders will need to be convinced the infrastructure is capable of fueling cars. A comment on that is in the next few slides from three different perspectives, practicality, technology, and economics. Simply speaking, can hydrogen fueling by successfully integrated into gasoline station forecourts? Next slide, please.

First is practicality. As the industry matures, hydrogen fueling stations must be able to at least approach the levels of throughput of gasoline stations. The higher volume gasoline stations can fuel anywhere from 200,000 to 400,000 gallons a month, and this translates into roughly 500 to 1,200 fuelings per day. If you look at a 750 to maybe 1,000 kilogram per day hydrogen station, that would perform on the order of 200-300 fuelings per day. This hydrogen throughput is on the same order of magnitude as a gasoline station, and we believe this is what is necessary to show the stakeholders that, yes, indeed, hydrogen stations with high throughputs have been real world tested and can operate at high throughputs.

The second item is on technology, the bottom slide here. Fueling five cars a day can be done with conventional technology, but fueling 250 a day will require new technology and undoubtedly the industry is developing that technology today. Linde has two leading edge technologies, one is ionic compression, which compresses the steel cylinder in the compressor with ionic fluid and that yields a significant increase in throughput and improved efficiency. We also have cryogenic liquid pumps, which can deliver even higher volumes of hydrogen with significant productions in energy consumption. And I think it is important to understand these are not ideas, these are not on the drawing board, these are not in the lab. Linde will deploy both of these technologies in real world auto fueling applications in Germany this year, so we can confidently say that the technology is available to do this type of fueling.

Another item I would also like to mention is that we're working on resolving the forecourt space constraints. As we all know, gasoline stations have limited space to have both gasoline fueling, as well as hydrogen fueling, and we need to find ways to not only bring the size of the equipment down, but find somewhere else to place that equipment. So we are looking at building stations with equipment below grade. Our first installation in Munich, it is already operational, and it includes the hydrogen tank located below grade, and we are just in the process of finishing commissioning our second below grade installation in Berlin, and that will include both liquid hydrogen and hydrogen compression underground, which absolutely minimizes the amount of space you're going to take on the forecourt. The example of that, and our rendition of that, is shown in the upper right-hand corner of that bottom slide. And the lessons that we get out of these installations will certainly be leveraged as we approach the day in California when this type of installation is warranted. Next slide.

The next item is economics. The capital cost of Linde's high throughput fueling stations are a small premium over existing lower throughput stations, and when one considers what the cost is per kilogram dispensed into the vehicle, the cost is drastically lower. The station design can be supplied by other liquid or gaseous hydrogen, and we believe the cost will be sufficiently low that, when we combine the cost of hydrogen fuel with the per kilogram cost of the hydrogen dispensed for the high throughput station, the overall cost of the hydrogen dispensed into the vehicle will be comparable to that of gasoline today.

And we don't believe it is wise to wait to deploy these high capacity stations in 2015 or later when significant numbers of cars are already on the road. In 2015, we hope that investors will already see the value proposition such that they are attracted to the market, and already investing in it in 2014 and ’15. To do that, we must be operating these stations by 2013, so we can prove to investors, to the stakeholders, that it is feasible.

This equipment has a long life and since these stations are very high throughput, we believe they can be operated well past 2015, and through the rest of the decade with very little additional investment, other than an additional dispenser as demand grows. Next slide, please.

Small stations are fine when building an infrastructure or when you need connector stations, but we need large stations and we want to serve customers truly cost efficiently, and at the lowest possible dispensed cost. This was true for the one pump station which certainly served its purpose during the last big infrastructure build-up, gasoline stations. But now it is replaced by larger and more economic gas stations. We will be seeing a similar development in hydrogen and we should manage that build-up today with the right balance of small, lower capital stations, and large more cost-effective stations.

On the bottom of this slide, you can see a web link to a study that was done by a consortium of European industrial and government organizations. It's available on that web link and contains a significant amount of detail on fuel cell vehicles, hydrogen production, and hydrogen fueling infrastructure, and I would strongly encourage those who are interested in further detail about the study to review the information.

Finally, I would like to just comment on a couple of challenges that we think require close collaboration between government and industry and, in fact, some of that collaboration has already happening and we just want to encourage that it expand and continue to grow. The first is with respect to local permitting and planning for alternative fuels. Hydrogen, like most of the other alternative fuels we're talking about here today, it's new and hence the public and public officials have to be very well educated to ensure unnecessary barriers are not placed in front of these stations as they're deployed. These type of barriers are just going to slow down the deployment and increase the cost of introducing alternative fuels to California. Already, Linde and the California Fuel Cell

Partnership are actively educating the communities where we will deploy hydrogen stations, but we do think it’s appropriate and important that this effort be expanded to include more stakeholders and be better coordinated going into the future to ensure that stations go in on time and can go in cost-effectively.

Another item I’d just like to comment on is dispenser certification. It is critical that we get to a point where we can charge for hydrogen on a per kilogram basis, and that will require certification by the DMS. The Energy Commission has granted money to DMS to actually do this, and we would just like to reinforce the need for all these stations to be certified in a timely manner, so that all stations can charge for hydrogen on a per kilogram basis.

So just a closing comment. Linde truly believes a business case exists for hydrogen fueling in the near future, and we’re investing money and resources in California and around the world because of this. We appreciate and encourage continued government support for infrastructure until the day comes when sufficient vehicles are on the road to load up our stations, and make this a value proposition that companies both large and small will want to pursue on their own. Thank you for your time.

VICE CHAIR BOYD: Thank you, Mr. Eckhardt. If you would stay on the phone, I think now is the time for any questions from folks in the audience of yourself or Mr. Heydorn. So are there any questions? Gina?

MS. GREY: Gina Grey with WSPA. And I think most of these questions I have are actually going to be directed to Linde vs. Air Products, but would appreciate responses from either company.

The first question is, I think I heard you say that, so far, between ARB and the AB 118 monies at CEC, that that will be funding 18 hydrogen facilities, but that you propose that we would need 40 in the state by 2015. Is that correct?

MR. ECKHARDT: The 40 is a number that has been proposed by the car companies in the California Fuel Cell Partnership.

MS. GREY: Okie doke, thank you. And Air Products mentioned, for a low volume station, I believe it was, a million dollar, I guess, investment for that. I was wondering the cost, I wasn’t quite sure on your slides, you mentioned a dollar per kilogram, but what would be a total cost for a high throughput facility?

MR. ECKHARDT: At this point, I couldn’t comment on specific dollar amounts for the higher – say, over 500 kilogram per day station, but we can say that it would be at a small premium to the stations we are supplying today, which are on the order of 200 kilogram per day stations.

MS. GREY: Small premium, okay, and what – I guess the dollars that are coming from AB 118, maybe we could go there for a second, per station, maybe that would give us some idea of what it’s costing right now. Are those low volume? High volume?

MR. ECKHARDT: The stations that Linde is supplying were noted in our proposals as 240 kilogram per day stations.

MS. GREY: At a cost –

MR. ECKHARDT: I can’t comment on any of the other stations.

MS. GREY: Okay, and do you have a cost for each one of those?

MR. ECKHARDT: No, I don’t have that at this time.

MS. GREY: Okay, I guess, you know, the question kind of surfaces that we’re pretty familiar with the fact that ARB has the Clean Fuel Outlet Regulation that went into play in 1990, it has not yet ever been triggered, it put the oil industry on the hook for mandatorily putting in renewable or alternative fuel facilities at retail and, of course, in 1990, our companies actually did have quite a few of those stations, they were owners, etc., as was pointed out earlier, currently I think there's only about two percent of the stations in California that are owned by the majors, so they are owned by small independent businessmen. So, a couple of questions here, you mentioned Germany, Japan, and I think some other countries that were moving ahead with putting in hydrogen facilities at retail; who is paying for that? Is that government, the taxpayer in those countries? And then, in your estimation for California, granted, we may have a Clean Fuel Outlet Regulation in place, but again, the folks who would have to fork over the dollars to put all these facilities in, even if they're a small volume million dollar type scenario, probably are not in the financial situation to actually move forward and do that, so do you foresee that this would be something that Linde and Air Products may move forward and do this, since you are forecasting a business case at this point for these facilities? Or are you looking for these additional 22 or so stations that the car manufacturers sort of indicated are needed by 2015, are those dollars going to be coming from, say, AB 118 or other sources?

MR. HEYDORN: This is Ed Heydorn. I can answer the question on station investment. In our docket submission to the 2011-2012 Investment Plan, we provided specific information on the amount of dollars that would need to be invested in Southern California. In our view, what would be sufficient to complete the roll-out of infrastructure in advance of deployment of vehicles, after which investment could be done on a more commercial basis because there would be enough volume of traffic through the stations to be able to support the added investment, either for new stations, or for expansion to existing stations. So, if I can refer you to the docket, I think that would be the best answer. We're very supportive of the continued efforts of the Energy Commission and staff to support hydrogen infrastructure, so we can make the projected deployment of vehicles in the 2015 timeframe successful.

MR. ECKHARDT: This is Steve Eckhardt. With respect to Germany, the funding for stations in Germany is both coming from government and from industry. I am not aware of how it's being done in Japan and Korea. With respect to California, you know, we encourage that we take a similar approach to that in Germany where it is both a government and industry investment here in the short term until there are sufficient number of cars such that industry can justify that investment on their own.

MS. GREY: Okay, thank you. And by “industry,” what industry is that?

MR. ECKHARDT: Those that are – anybody who would want to invest in putting a hydrogen fueling station in – when someone who wants to invest in a hydrogen fueling station sees, as Ed had mentioned, sees the number of cars out there that will justify that investment, so it could be investors, it could be oil companies, it could be industrial gas companies, it could be anybody.

MS. GREY: Okay, is Linde one of those industry partners there?

MR. ECKHARDT: Yes.

MS. GREY: Okay, thank you.

MR. HEYDORN: As is Air products and many of the other industrial gas companies are participating in that study, as well – the actual implementation.

VICE CHAIR BOYD: Excuse me, any other questions? All right. Seeing none, thank you, both gentlemen, for your presentation.

MR. ECKHARDT: Thank you.

MR. WENG-GUTIERREZ: So I think, with that, we are going to break for lunch, so we are a few minutes behind schedule here, but not too bad, so we’ll come back – I guess we'll return at about 1:45, so we'll take a little bit over an hour for lunch.

(Recess at 12:42 p.m.)

(Reconvene at 1:50 p.m.)

MR. WENG-GUTIERREZ: We still have a long afternoon in front of us and we're about 25 minutes behind where we thought we would be, so that's not too bad.

But we're going to go ahead and just jump right into it. The next speaker we have is Matt Horton, from Propel Biofuels, and he'll be talking on the biofuels in retail station permitting. So, if you could come up?

MR. HORTON: Great, thanks. Good afternoon everybody, excited to be here.

I'm going to walk through some of the real-world experience that we've installing a bunch of E85 locations here in California over the last couple of years.

VICE CHAIR BOYD: How painful will this be? No.

MR. HORTON: I'll show you the scars in a minute.

But I just wanted to start with a couple of slides about Propel. I know a number of you are not real familiar with our company. But our mission is to build a brand around clean fuels and we want to build a leading clean fuel brand. And we’re doing that by building out a large number of retail access points where customers can become familiar with renewable fuels. One of those is E85 Ethanol, today.

Our model, we’ve really set up our business to try to be a good partner for the existing fueling infrastructure. We work with individual station owners to bring new fuels equipment to those sites, the equipment required to dispense -- store and dispense renewable fuels.

We partner with the existing site owners, so we offer all of the, you know, marketing, customer outreach and a lot of the activities, and services that we think are really important in early stage markets, like this, to help customers get comfortable using renewable fuels for the first time.

And for us, this approach provides a number of benefits. It helps us keep our operating capital costs lower, it helps our stations become profitable, lower volumes. And we’re really focusing on building the scale of the network so that we’re in convenient locations for the customers, and providing them with some brand consistency to help drive some loyalty and confidence in the fuels that they’re purchasing.

Today, Propel has the largest number of E85 locations in the State. We’ve got 18 that we’ve opened today, 23 are in permitting right now, we’re working through that process and hope to opening a number of those soon. We’re pleased to be -- have a grand opening on our Redwood City site next week. And anyone who would like to is invited next Tuesday, in Redwood City.

We’ve got a number of other contracts that are signed and ready to go into permitting right now. And our plan is to bring about a hundred fifty of these stations to the State of California by 2015.

Here are a couple images of the work we’ve done so far, with some of the station partners that we’ve worked with. We have two installation types, typically. There’s one that we offer that is a stand-alone option, where we can -- we essentially build our own small canopy on the site of our station partner.

And in other sites we’ve worked with the station owner to actually install a dispenser, a Propel dispenser under an existing canopy. So, there are a few images, a couple of these are here in Sacramento, and one of those is a Southern California site.

We are, just to mention, we’re in Sacramento, the San Francisco Bay Area, and L.A., and San Diego at present.

We think there is tremendous upside in

California for renewable fuels, in particular for E85. Nationally, you know, the numbers say that there are about 1,500 cars per gas station. In California we have 7,600 flex fuel vehicles for every E85 station out there.

So, today we've got a large vehicle base that is relatively under-served. And in California, alone, if we were -- if those flex fuel vehicles all had adequate access and were using E85 regularly, we could displace about 255 million gallons of petroleum per year, starting right now.

So, yeah, our experience, you know, we are a -- you know, we're a start up company a couple of years ago. We've received some very strong backing from some leading clean tech venture capital funds. We continue to get strong interest in what we're doing.

As we've mentioned before to this group, a big part of that is because we are a partner with -- you know, have been able to do a public/private partnership with the State of California to provide some of our own capital in combination with the grant programs that are -- that have been made available by the Energy Commission.

But I do want to also note that it's -- while we get a lot of interest by the private sector, the importance of these grants to this program is key. And because the programs are available we are able to attract the private capital as match. But this market really is in the very early stages, volumes are still relatively low and continuing public/private partnership is very important in this market to help mitigate the risks and the costs of the equipment.

Some things that we have learned here, in California; the installation costs that we've encountered in the State can vary widely, from somewhere in the neighborhood of $275 to $375 thousand dollars depending on the configuration of a station site, the amount of work that needs to -- that needs to take place to put in all new infrastructure to be able to handle these fuel types.

So, we've taken an approach where we -- we bring entirely new equipment to the site. We're not in the business of retrofitting existing equipment because we want to make sure that we comply with UL requirements and, you know, with all of the regulations.

One thing that we have noticed in working with a grant program is the cost of Davis-Bacon Act compliance are significant. We've been encountering costs as high as $45,000 of additional cost in terms of labor, so that's been one of -- one key challenge with regard to getting these stations completed on a reasonable budget.

The other, and this is really what, you know, I want to talk about today is some of the -- there are a lot of challenges with regard to permitting, because in many of the jurisdictions that we enter it's the first time that the fire marshall, and health and safety, and other folks have had an opportunity to work with a renewable fuels company on these new types of fuels, so there's a lot of education that's required.

The way that we do our business, being a separate retailer on the same site, also creates some minor challenges, just making sure that we're coordinated well in the regulatory databases, et cetera.

But the biggest thing that we've run into is that this is still very much a municipality by municipality type of permitting operation, it's a brand-new process every time. And, you know, the learning curve for each of these agencies is quite steep.

And one of the things that we're looking at is, you know, finding ways to work with the State agencies to help -- to help provide educational materials to the local folks, and provide some leadership and guidance on what it takes to get new fuels implemented in new infrastructure today.

Another challenge that we run into on

permitting, that does delay the process, as many of -- many station owners today currently have issues with compliance with local regulations, they're out of compliance for some things that they've done. And because of that the process gets slowed down a little bit until site owners come up to compliance.

And, finally, you know, these local authorities, under the conditional use permits, have broad latitude in being able to hold up a process. And so, again, we think education is really important, but hitting that conditional use permit in almost every site that we're at adds significant complexity and time to the build schedule.

So, we've been making, as a company, great progress, we feel, in breaking down some of those barriers, but they are real and they do exist.

You know, these -- I guess the key here is that this is new, it's the first time that most contractors, inspectors, people with agencies have ever dealt with these issues and that adds a lot of time and cost to the job.

So, things that we are looking for is the additional support from some of the State agencies to help streamline that process and get some better education out to the local agencies.

We have found that when we do make the fuels available that the customers love it. We've been seeing a pretty strong response. And we've really found three keys that we have learned from our customer base. Consumers need access in convenient locations. They're not going to drive, you know, too far out of their way and they don't want to go behind the fence in, you know, a fleet yard somewhere to find their fuels.

So, we need to make these fuels available in places that are convenient for customers. People have a lot of questions about these fuels and so providing them with confidence that there's a company that stands behind the fuel, that it's a high-quality product is really important and that we'll be with them to help get them through any issues that may come up, and provide them with really good customer service has been real important for us.

And we've learned a few things about the value equation for consumers. On the biodiesel side, we know there is a small population that's willing to pay a premium, but it is a very small population.

The general public really doesn't -- is not interested in paying much of a premium for diesel replacements.

For E85, we also do know that we need to be able to offer a strong value proposition, a significant discount to the price of gasoline to make sure that customers that experience some mileage drag are still getting good value for their money.

And we do think that continuation for high level -- or for support of high-level blends, from a tax stand point, is continuing to be very important while this fuel gets established and becomes more mainstream.

So we, as a company, are looking at lots of ways that we can supplement the income from -- you know, from the station assets we're putting in place. We're getting involved in some limited bulk and commercial fuel sales. We're active in the markets for trading and sales of rims.

We are very interesting in seeing how the low-carbon fuel standard market develops in terms of credit, sales, and other opportunities there. I think that can provide a strong additional financial support for these products, and we're looking into other -- other new fuel types, both blends and types of fuel to be able to offer it to customers.

So, one of the questions that was asked of us is what does -- you know, what does the future look like for renewable fuels and E85, in particular, retail in California?

We think it’s a very strong opportunity, lots -- a good market opportunity that’s growing, but it is still small today.

We do feel like we’re making great progress on understanding the customer better and understanding the return on investment from these stations. But it is a market that’s absolutely in its infancy. You know, we are working with customers to make transitions and they are -- we are working with an infrastructure that’s been in place for, you know, many decades in most cases.

And we think that we can achieve a pretty rapid pace of change here in the State, but the incentives that the Energy Commission has put into place are going to continue to play an extremely important role in driving the adoption of renewable fuels infrastructure.

So, a couple of things, just final thoughts on how, you know, this body can help. We would welcome the opportunity to work with other agencies to help -- help endorse this kind of program to municipalities, to help them understand the importance that it has for the Energy Commission and the State of California.

Continued support from AB 118 is very important to E85 in California.

We are also, unfortunately, engaged in a very heated debate at the national level about ethanol, and the role that it will play going forward. We think California has shown strong leadership. It's been very helpful to me, and our company, as we're in Washington to talk about the leadership California's showing on E85 and renewable fuels.

And any opportunities to help weigh into that debate I think would be very -- it would be greatly appreciated.

We also have a situation in California where we have thousands of flex fuel vehicles that the State owns. We've developed a partnership with the Department of General Services, but some continued assistance with those State vehicles to make sure they're aware of where the outlets are would be of help.

And, again, working with municipalities and agencies not only on permitting issues, but helping them become a customer, in the same way that the State has been a great customer for us, would also be greatly appreciated.

So, with that I've reached the end of my comments today. I don't know if we have any question time or --

MR. WENG-GUTIERREZ: Yeah.

MR. HORTON: Okay, great.

MR. WENG-GUTIERREZ: So, if there are any questions from the dais?

VICE CHAIR BOYD: A quick question, Matt. I don’t know if you were here this morning when I broached the question about biodiesel versus renewable diesel and whether biodiesel really -- whether it had a big future. And I just wondered if you had any views on biodiesel, and recognizing just like ethanol E-10, California, versus E-15 desires, and in some parts of the nation, biodiesel has the same percentage hurdles; warranties by manufacturers, other concerns.

Do you -- what do you see going on in the biodiesel arena, in particular?

MR. HORTON: That’s a great question. Our company actually got started focused on biodiesel, so it’s near and dear to our hearts, and we’ve really grown up as a company with biodiesel. We’re aware of the limitations that exist, but we think it does have a -- continues to have a strong future.

Because of some of the limitations that you mentioned we are very interested in participating in demonstrations and pilot programs to learn about renewal diesel, we think it does offer some -- you know, some attractive opportunities in the way of higher blends and compatibility with the existing vehicles today.

So, today, you know, we -- I would say much like on the ethanol side, we have an eye toward the future, cellulosic ethanol, other advanced ethanols, ethanol products. You know, we think that the business for biodiesel is strong, pretty strong at present, but may transition over time to other fuel types.

And our commitment to our customers is we want to provide them the most sustainable fuels that meet quality and cost targets.

VICE CHAIR BOYD: Okay, thank you.

Any questions from the audience, since this is a panel of one?

MR. WENG-GUTIERREZ: I think we have a staff question.

VICE CHAIR BOYD: Guess not. Thanks Matt.

MR. SCHREMP: Gordon Schremp, Senior Staff. Matt, I have a couple questions for you.

Are your -- is your companies activity at these existing sites, through a lease arrangement, are you an obligated party under RFS2 regulations, as well as an obligated party under LCFS regulations?

MR. HORTON: We are not obligated under -- we are not an obligated party under RFS, so we view ourselves as essentially a source of compliance for those who are because we do generate a tremendous number of RIN credits, and view ourselves as a natural partner in that opportunity.

With regard to the low carbon fuel standard, you know, we're very sort of interested to see how it's going to -- how it will -- how it's taking shape and what the opportunities are there for, again, being a compliance opportunity for partners that are obligated.

MR. SCHREMP: And I guess a final question is I noticed that for your customers dealing with or having a correct, or appropriate price for E85 to deal with the fuel economy difference, how does -- how does Propel feel about maybe providing enough information to consumers and along the lines of, say, fuel economy equivalent pricing for 85, recognizing there are some variabilities in the 85 blends, and seasonality of gasoline energy contents.

But how would you feel as a company about trying to provide some additional information to consumers along those lines?

MR. HORTON: Yeah, good question. Yeah, we've actually found that our consumers are fairly educated on the issues. People who drive flex fuel vehicles and have any experience with E85 understand, you know, the lower BTU content. Certainly, there are some that may not.

We think the right thing to do is to educate customers on that. We think it's in their best interest, and ours, and as an industry to make sure that we have an educated consumer base. So, yeah, it's something that we do try to educate consumers on, yeah.

MR. SCHREMP: Thank you. Do you have a question?

MR. STEVENSON: Just a question. Dwight Stevenson, with Tesoro. So, you do blend the ethanol and base fuels together?

MR. HORTON: So, today we're not doing blending, ourselves --

MR. STEVENSON: You aren't, okay.

MR. HORTON: -- we're purchasing a pre-blended fuel.

MR. STEVENSON: Okay, thank you.

MR. WENG-GUTIERREZ: Perfect. Thank you so much.

And next we'll be going to Jim Uihlein, from Chevron. Is he online?

MR. UIHLEIN: Okay, hi, thank you for the opportunity to talk to this group today. I'm going to be talking a bit about some experiences that Chevron picked up in doing an E85 demonstration program here, in California.

Flip over to the next slide. The demonstration program was done in cooperation with both the Air Resources Board and CalTrans, we were providing E85 to a test fleet of FFVs at two different locations that CalTrans had, both of them being fleet locations. One was in Oakland, the other one was in Marysville.

We provided fueling equipment. It wasn't really completely retail compatible. It consisted of an above-ground storage tank, with an associated dispenser and then, of course, a hose and nozzle also associated with that.

It was more of a temporary installation. The dispenser was kind of approaching retail ready, but we -- given that it was a fleet location, behind the fence, we went with what worked for that environment.

One of the things we did run into in providing the equipment for that was the discovery that there were no certified E-85 enhanced vapor recovery systems available, and so we had to go with a dispenser that lacked that sort of vapor recovery system on it.

The next slide. Our goals in this program, just speaking from Chevron, was number one to assess vehicle performance and customer acceptance as part of that. We were looking at things like mileage and emissions, of course.

We're looking at how the vehicles performed and it was a couple-year program, and so we had an opportunity to get observations over the range of seasonal conditions.

It was also long enough that there was an opportunity to get data on maintenance needs and, also, how the driver responded to the use of the fuel.

For our part, of course, we’re also very interested in investigating some of the aspects of delivering E85 to a customer installation, in terms of blending, and transportation, and dispensing it to the vehicle.

And so, naturally, the activities that we were directly involved with around the blending and transportation we have a lot of information.

Of a lot of the other information, more on the vehicle performance side, the Air Resources Board has that information. We don’t have access to it at this point.

There’s a final report that we understand is underway at ARB, but it has not yet been released.

We think that in addition to our interest in finding out some of these things about the program, we also think it would be a useful source of information for IEPR. And so anything that the Energy Commission could do to help expedite that report out of ARB would be very helpful and very much appreciated.

The next slide. One of the aspects I wanted to talk about specifically with our experience in providing E85 in the State was what we had to go through in order to blend an on-spec product.

And the biggest issue that we were confronted with was that if you add CARBOB and ethanol you don’t get an on-spec E85 at any of the blend ratios that are permitted by ASTM.

The ASTM 5798 spec is really the standard for E85, or what ASTM refers to as an E72 E85 fuel. And DMS enforces the ASTM within the State.

It covers a lot of properties, but the two that we’re really concerned about with this particular issue were RVP and the minimum ethanol content.

And just to give an example of what we were faced with; in the summertime the E85 spec is a 5.5 minimum RVP. CARBOB runs a little bit above that, generally, but -- and pure ethanol has an RVP of 2.3 pounds. And so when you mix those together, depending of -- at a ratio of 15 percent CARBOB, 85 percent ethanol, you end up with an RVP of somewhere in the 4 and a half to 5.3 range, a little bit below spec, but really never -- never actually getting up to the spec.

And I should note that while the pure ethanol

RVP is 2.3, everything we used is, of course, denatured, and so the actual RVP of the denatured ethanol will depend somewhat on the nature of the denaturant. If it’s something like a natural gasoline, it may have a little bit higher RVP. If they use a normal gasoline or a BOB, it would be something lower than that. That tends to range from 4.5 to 5.3, that we would actually observe.

The next slide. So, there were -- are a couple of options to increase the E85 RVP in order to get it on-spec. One thing you can do is increase the proportion of hydrocarbon to make it a bit less than 85 percent.

The other option is to try to increase the RVP of the hydrocarbon using a third component, which is what we ended up choosing to do for this particular exercise.

The ASTM specs at the time were fairly rigid and so there wasn’t a whole lot of wiggle room for increasing the proportion of hydrocarbon. I’ll talk about that a little bit later. But it was just easier to try to use a third component to help pressurize the hydrocarbon.

We chose isopentane just because we had it available. We got a little pressurized tank that was actually like on a trailer that we would use to pressure up the batches as we blended them into a truck.

Blending results over the course of the program, we had to add somewhere between two and a half to 6.8 percent isopentane. The two and a half was kind of a one one-off. We average around 5.2. So, it was a fair amount of isopentane to add in there in order to get it up to pressure.

The next slide -- ah, thank you. The commercial implications of all this is that if you look at the current terminal infrastructure, it's really fully and efficiently utilized. They've got tanks for CARBOB, they've got tanks for ethanol, but there's nothing there for a third component.

The other aspect of this is that the third component can't use just any old tank because naturally what you want to increase the vapor pressure of this stuff is something that possesses a fairly high vapor pressure, and so it's going to require pressurized storage of in order to get it into the terminal.

And, actually, when you look at the available pressurants that you might use, butane has some advantages and that, you know, typically that would be in a sphere type storage in bulk applications, that you may be able to do something with rail cards for this.

But in any event, it’s not going to use an ethanol or a CARBOB tank.

The other aspect of this is right now terminals aren’t in the business, generally, of blending to specifications. They handle volumes and volume ratios really, really well, but that presumes that you can give them, you know, the right volume and/or the ratio and they’ll hit it with a high degree of accuracy.

Something like this is really a finished product blending to a spec, more like we do in the refinery, which is not typically a terminal operation at this point.

Then the variations come in both the ethanol denaturant, as I mentioned, affecting the ethanol RVP and variations in CARBOB.

And so blending to hit a spec and monitoring to make sure that you hit that spec in the final product, again, is somewhat foreign in the terminal environment at this point.

And the next slide. Also, the other thing that’s happened since our demonstration program is that ASTM has made some changes to the D5798 standard. They’ve relaxed the minimum percent ethanol somewhat. It’s now 68 percent year-round, which means that effectively the E85 is somewhere between 68 and 83 percent ethanol. That helped. But when you look at the situation in California, it doesn't eliminate the need to do third-component blending, it just reduces the amount of whatever that third component is that you'd need to use. You would still have the infrastructure requirement to try to set up to do terminal blending of E85 in the State.

ASTM is also considering a shift to a flexible fuel specification, rather than a strictly E85 or, as I mentioned, E72 E85 specification.

This would drop the minimum ethanol content down to 51 percent year-round and that brings you very close to being able to blend this flex fuel vehicle fuel without using a third component.

There's still an issue or two in shoulder months, where the seasonal specs for the E85 don't completely match the gasoline that's available, that you would expect -- or, rather, the CARBOB that you would expect out in the field.

But the third component blending would result in what we currently think of as E85 containing somewhere between 51 and 75 percent ethanol. So, it would be pretty short of E85 at that point. And that, again, would depend on the season, with the summer getting some of the lower concentrations when most of the driving gets done.

So, I guess the main points that I was trying to relate from our experience is that retail infrastructure is really not the only infrastructure issue for E85. We’ve also got some issues at terminals, to be able to set up if this were ever to be done on a large scale.

And even if the ASTM standard changes, that alternative would be to produce a flex fuel vehicle fuel at lower levels, but then that ends up increasing the volumes required to move the same amount of ethanol, you know, for compliance with things like RFST2 and the LCFS. And it also makes other problems, like the lack of FFVs in the State even more limiting.

And with that, I’ll take any questions.

VICE CHAIR BOYD: Thank you. Questions?

Gina and then I think Gordon has questions, as well.

MS. GREY: Gina Grey, from WSPA. I think this is a question probably more for Mr. Horton, but Jim’s presentation kind of triggered this question relative to changes in ASTM.

I know that ARB has been, over the last year or so, proposing some changes to the E85 specifications and we, as WSPA, for one, have submitted comments on that mainly along the lines that, you know, ARB should probably just go along with ASTM and not create a whole new set of specifications for E85 in California, that are different from the rest of the nation.

So, I guess to Mr. Horton, what would ARB's changes to the E85 specifications do, do you think, to the prospects for E85 in California.

And if you're not familiar with what they are proposing, I have written down here, I guess, changing the RVP and also changing the limits on benzene, aromatics, olefins, and sulfur.

Sorry. Yeah, go ahead.

MR. HEYDORN: So, I guess the way that I would address the issue or the question, and it's a good, is, you know, again, we think -- we look at this segment of the industry as just barely emerging, just getting on its feet. And the, you know, changes that a new spec might require in terms of, you know, the boutique fuels and things that would be required to meet spec, would make it even more challenging for E85 to be cost competitive as a motor fuel.

So, yeah, our strong preference at this point is, you know, to maintain sort of the test fuel type of exemption we're operating under until the volumes get to be large enough that the infrastructure is efficient in delivering whatever blend stocks are required.

MR. SCHREMP: And then I just have a -- this is Gordon, I have a clarifying question for you. So, under your test program for marketing these fuels, essentially the E85 is created by starting with an E10 blend and then adding E99 until it gets up to an E85 spec. Is that sort of how it's created versus the dynamic that Jim Uihlein described in how they created E85?

MR. HEYDRON: To be honest, I'll probably need to defer the question to some of our more technical folks. Jim, can you -- yes? Yes. Yes.

MR. SCHREMP: Thank you.

MR. WENG-GUTIERREZ: If there are no other questions from anyone online, or in the room?

Okay. I had one quick question for Jim. I just -- you had mentioned an ARB report that we might to get a hold of. Do you have a contact name for that person or who were you working with?

MR. UIHLEIN: Probably the best person to talk to would be Mike Waugh because it's in the fuel section.

MR. WENG-GUTIERREZ: Great, he's here today, so we'll catch him before he leaves.

MR. UIHLEIN: I didn't -- nobody tipped me off on that one, either.

(Laughter)

MR. WENG-GUTIERREZ: All right. Thank you, Jim.

VICE CHAIR BOYD: Thank you very much.

MR. WENG-GUTIERREZ: And next we'll have Eric Bowen come up and speak.

MR. BOWEN: Good afternoon everyone. I'd like to thank Commissioner Boyd and the Energy Commission for inviting me here to speak today. My day job is with Renewable Energy Group, the nation's largest producer and distributor of biodiesel, about 20, 25 percent market share.

One of the things I do in my volunteer time is serve with the California Biodiesel Alliance, I'm the Chairman of our State Trade Association here in California for biodiesel.

Before I get into my presentation, I'll start with you, Commissioner Boyd, and I greatly appreciate the interest that you've taken in trying to figure out the answer to what is the future of biodiesel? You've asked that question, I think, two or three times now and, you know, we've met before and discussed this.

And I guess I think that John got it right when he said that both will be here for a while. And I think Matt also got it right when he said we don't know what the future holds, but we're going to take what the market has available and customers are asking for today, which is biodiesel.

And I suspect from our prior conversations, and conversations I've had with staff, that part of your questioning is motivated by what's the most effective and efficient use of limited State resources and should any of those go towards biodiesel, not knowing what the future of that fuel may be.

So, I've posited that the future of biodiesel is strong and it will be with us for quite some time. But I'm also willing to say that should I be wrong, and I don't think that I am, you actually don't have, I think, the problem that you think you have.

All of the infrastructure for biodiesel that would give the State the biggest bang for the buck would happen at the terminal, and it's about segregated storage at the terminal and ability to blend that fuel into petroleum diesel.

Renewable diesel is going to need that exact same infrastructure. So, if we don't build it today for biodiesel, it won't be there tomorrow for biodiesel or renewable diesel.

So, you know, we've got 50 some terminals around this State. And as Jim Uihlein mentioned in his presentation, one hundred percent of those have infrastructure for gasoline and for ethanol, and we can create low blend and high blends of ethanol. And there's some limitations on the high blends that he highlighted, I think quite effectively.

Not one of those has storage for a renewable diesel fuel, whether it's a biodiesel or a hydro-treated renewable diesel. And because of that it's extremely difficult for biodiesel to enter the petroleum fuel supply stream, or just dropt the word "petroleum", the fuel supply stream.

And California really lags the nation in this regard. Other states have put that infrastructure in through both private and public investment, and where that is there are thriving biodiesel markets.

And so we're, I think, really missing an opportunity to improve California's energy independence, as well as reduce California's carbon emissions through the diesel fuel pool by not investing in that infrastructure.

And I'll get into that a little bit more, but I wanted to start by directly addressing your questions, Commissioner Boyd, and letting you know that you can take comfort and money will be well spent for both fuels.

VICE CHAIR BOYD: Thank you. I knew I'd set you up pretty good there.

MR. BOWEN: I appreciate it.

I mentioned California Biodiesel Alliance, the State's -- so, four things I want to touch base on here today, and I've been asked to speak about biodiesel fuel quality and storage issues.

First, I want to say that fuel quality has never been higher, and I'll get into what I mean by that here, shortly.

Second, I want to let the Commission know and the audience know that biodiesel is back in a big way based on RFS2, and it looks very, very different than the biodiesel industry that you probably think you know; massive consolidation, rationalization, and professionalization of the industry.

California lags the nation, and why I think why we have an impression of biodiesel circa 2007 or 2008, because of this lack of infrastructure that we've been talking about, as well as this regulatory uncertainty. And I'll spend some time getting into those two topics.

And the good news here is that these are actually comparatively inexpensive problems to fix.

So, first off, biodiesel fuel quality. I think it's fair to say that biodiesel is now a drop-in fuel, and this is a big deal. Biodiesel is as much a drop-in fuel as low blends of ethanol.

In 2008 ASTM changed the definition of diesel fuel, D975, to include up to five percent biodiesel. Biodiesel can be shipped in pipelines, those that do not have jet fuel. Unfortunately, that's a limited California opportunity, but that's a huge national opportunity and biodiesel is shipped in pipelines today.

And all of the engine manufacturers, through the ASTM consensus process, have all approved B5 with theirs. Many engine manufacturers have approved B20 and we're adding more and more to that list every day, and there are some engine manufacturers that even have approvals above that.

So, the point being that, yes, today there is somewhat of a blend wall at five percent. Even that is an enormously large opportunity that we're not taking advantage of.

It's reasonably foreseeable to see that blend wall increasing to 20 percent in the short future, and there will always be NISH applications, mining, agricultural, particularly environmentally sensitive fleets that can use even higher blends, as you know well, Commissioner Boyd, all the way up to pure biodiesel or B100.

So, how has RFS2 changes the industry and what does this mean for what it is to have the new biodiesel industry?

So, I want to do a couple quick corrections from John's presentation this morning, just to make sure that we're all operating under good, current, correct information.

The RFS2 requirement for 2011 is 800 million gallons of biomass-based diesel, and that's biodiesel or renewable diesel. And that has to have at least a 50 percent carbon reduction or qualify as an advanced biofuel under federal rules. USEPA and CARB think about that a little different, so soy biodiesel qualifies federally, while that would not qualify as an advanced biofuel here in California.

That increases to one billion gallons next year and then EPA has discretion to increase it thereafter.

In addition, because biodiesel is defined federally as an advanced biofuel, it also participates in the bucket of generic advanced biodiesel, where cellulosic ethanol also participates.

But unlike cellulosic ethanol, where there really is no commercially available quantities, we're talking about hundreds of millions of gallons, over a billion gallons of installed production capacity in the United States, today, of biodiesel.

I was asked to address what role of imports -- I'm using BD here for biodiesel, RD for renewable diesel. I think biodiesel imports may come in, but we're not seeing a lot of that today, and we'll wait and see how that develops. That has a lot to do with registrations and being RFS2 compliant.

Renewable diesel, we may see some of Neste's product, but quite frankly I think it goes to Europe and Asia, we probably do not see it here. We also don't have the marine infrastructure to take it in.

And sugarcane ethanol, once all the ethanol stuff gets rationalized, we probably will see.

With regard to California LCSF, there's an opportunity for obligated parties, several of which are in the room here today, to double dip their compliance requirements through RFS2 and California LCSF by meeting their RFS2 requirements here in California.

I view this as a good thing. Normally, we think of a double dip as a bad thing. In this context it's a good thing because it allows California to lead the market with these clean renewable fuels, and we really need to be more actively thinking about how we do that, and I know today's meeting is a lot about that.

Unlike RFS2, which has specific buckets for fuel, the low carbon fuel standard is market-based, so it's less clear what fuels will be used. And I really think that's what's been motivating some of Gina's comments to the electricity providers, and others, of who's going to come into LCFS, what are these credits going to look like?

Because if you're an obligated party, nationally you know you've got to have your portion of the 800 million gallon biomass-based diesel mandate, that's pretty clear.

In California, you don't know what you have to have and so we need to figure this out. Several of us in this room, actually, including myself, sit on the ARB Advisory Panel, trying to figure this stuff out. But it's going to be a while before LCFS is a true market driver of clean fuels in California is my personal opinion.

So, getting to the point, again, about leadership and market opportunity here, if we did just B5 in California, and we just did that across the State and, you know, the states like Illinois are already doing B11, so this is not a hard thing to envision or to actually accomplish.

If we just did a B5 here in California, and we did that from waste feed stocks, used cooking oil, inedible corn oil, animal fats, that's about 160 million gallon per year opportunity here in California, easy for the biodiesel industry to supply that volume of biodiesel. And that would represent a four percent carbon intensity reduction on that diesel. And this is overnight, this is low-hanging fruit, this is stuff that we should be doing.

As that blend wall gets increased and we go towards B20, you can see a 15 to 18 percent CI reduction in the petroleum diesel. Our goal for 2020 is ten percent in the fuel pool. We can do this on the diesel side quite easily, I think, over a five-year period, if we put some effort into it on getting everything up to B20.

So, again, do I think we'll get there? Not without a lot of effort. If we wanted to get there, do I think it can be done? The answer is absolutely yes, those volumes are available, those CI reductions are available.

So, what is holding back the market? Well, I opened up with it, so it's lack of infrastructure.

So, terminal storage is priority one, two and three. The second is how do you get the fuel into that terminal storage?

There's a lack of available rail off-loading, and a lot of it, I think, is monopolized by the ethanol coming in. But we've got to figure out that piece of how do you get fuel into the terminal after you've put the tank there.

Then, of course, you need rack blending, and then I’ll get into the UST issue here a little bit later.

Then on the regulatory uncertainty side I know there’s been comments coming out of CARB about concerns about NOx, and I want to get into that in more detail here, shortly.

And then I’ve already indicated low carbon fuel standard is not sending any clear market signals.

For renewable diesel, the real holding back there is costs, and it’s both a capital cost and an Op. ex., and I’m more than happy to spend more time on that, but in the interest of time for now I’ll just move on

So, what is this terminal opportunity? Well, as I said, biodiesel or renewable diesel is going to need terminal access to enter the fuel supply. With our 50 terminals, not one terminal currently has this storage capacity.

That lack of infrastructure as a really material effect on the magnitude of 10 to 25 cents per blended gallon. So, if you’re doing a B5, that’s 10 to 25 cents extra, or a B20, 10 to 25 cents extra.

If you load all of that 10 to 25 cents on the B5 portion, you’re essentially multiplying that by 20 is the cost penalty for that B100 that it has to achieve to have price parity with petroleum diesel. It’s too much extra logistics cost for it to be able to handle.

On the other hand, if you had this infrastructure, you’re talking 2 to 4 cents, almost immaterial.

And it’s not a big investment, so my conversation with terminal owners, it looks to be about a 1 to 3 million dollar investment depending on the tank, the location, and permitting, all of those types of things.

So, you’re talking about a 50 to 150 million dollar investment here. Well, the private sector would gladly do a 50 percent match on this. We get a really quick ROI on this and it’s multiple fuel. It can be available for biodiesel, renewable diesel, any other distillate products that come down the road, so this is never going to be lost or sunk costs.

So, let’s get into underground storage tank, because I know this has been a concern for folks. We can’t do biodiesel because of the underground storage tank problem.

Well, first off, there’s not an underground storage tank problem at B5, we dealt with that a while ago. And, secondly, there is a solution for the short term on B20, through the variance program we put into place. The reason there was -- there was never concern about biodiesel causing a leak, there's not one known instance in the entire country, or even in Europe, of biodiesel causing a leak in an underground storage tank.

The problem was there was no UL approval, and California law required UL approval. So, you just couldn't get over that hurdle and you can't get UL to act quickly.

So, the Federal EPA is actually stepping into this void and going to help create some new programs that California should be able to piggyback on, that will solve this problem all the way up to B20. It isn't going to happen tomorrow, but it will probably happen in the next couple of years.

On the other hand, renewable diesel is no panacea. There is no ASTM definition of renewable diesel. There are unknown compounds in renewable diesel. And you can't put renewable diesel in an underground storage tank today, it's got more problems than biodiesel has.

So, I don't want us to think that there's this great fuel that can come down the road, renewable diesel, so we just need to wait for it and not support the fuel that's here today, which is biodiesel. The reality is we need to support both and supporting both is actually complementary to both and not competitive.

So, let's get into NOx. So, the graph up here is the federal information and you'll see that essentially at most blend levels there's, essentially, no NOx increase. Most importantly, let's focus on B5 to B20.

Now, the reason this is true federally is because, as everyone in this room knows, there's a different stand for Federal ULSD than California ULSD. So, we have a higher cetane, lower aromatic diesel, which is a good thing. I'm an asthmatic, I like the improved air quality.

And when you add biodiesel to California diesel spec you see a slight -- you see, basically, no NOx increase here federally. You see a slight increase at some blend levels here in California, but we don't know what it is.

The science seems pretty clear and a number of people, both in the petroleum industry and the biodiesel industry are working on this, that blends up to be 5 or NOx neutral, and we should just acknowledge that and move on.

And then for blends of B6 and above, up to B20 there might, emphasis on might, be a NOx increase depending on the feedstock of the biodiesel. So, a low saturated biodiesel, made from a feedstock like a soybean oil, likely yes. So, you'd have to have some sort of NOx additive or cetane enhancer.

A high saturated biodiesel, like something made from a waste product, a used cooking oil or animal fat, has a very high natural cetane, probably has no NOx increase. And even if there was some that needed to be addressed, again, there's a very simple industry standard cetane enhancers, and NOx things.

So, the bottom line, all of this can be addressed.

The regulatory uncertainty that CARB has created has chilled the market, because if you're Kinder Morgan, you don't want to write a $3 million check to put in a tank, to do biodiesel blending, not knowing what ARB's going to do about the future role of biodiesel in the California marketplace. So, we've got a real chilling effect going on.

But the reality is this is going to be solved in a couple of years and we need to be moving now to have the marketplace be ready.

So, what does this future state look like? There's a lot of biodiesel available, with a very low CI, from U.S. producers, with this drop-in opportunity today to B5.

Renewable diesel will come. My company will be one of the ones that makes it. I want to be very clear, I’m pro renewable diesel. But it’s not here today and it’s not likely to come for a while, and it does have disadvantages over biodiesel from a cost stand point, so we need to figure all that out.

Virgin oils, the palms and the soys, will have a role to play, but they have higher CAs and higher costs, so everything’s going to be waste in the early years. I bet you it’s 50 percent of U.S. biodiesel production today is from waste materials.

Over 90 percent of the biodiesel my company made last year and, again, we’re the largest producer in the country, waste materials. The industry has gravitated over to super high quality fuel from waste materials, driven by economics, clear and simple, they’re lower cost feedstocks and you can still make great fuel.

But here in California there’s an acute lack of infrastructure for renewable diesel and biodiesel, and we need to begin to invest in this infrastructure to take advantage of the opportunities to day on biodiesel, take advantage of the opportunities tomorrow on renewable diesel. And ultimately, down the road, the opportunities that, hopefully, you know, algal-oriented fuels, both algal biodiesel and algal renewable diesel will present the State to increase and go into higher and higher blends of biodiesel.

I'd be more than happy to answer any questions.

VICE CHAIR BOYD: Just one question comes to mind about the lagging infrastructure here versus other states. Are the other states, and you mentioned Illinois, for instance, is not unlike corn has driven the Midwest, does -- do agricultural commodities like soy diesel, and what have you, is the farming of that, does that add added pressure in some of those areas to adopt programs that facilitate the -- that type of fuel, more than California?

MR. BOWEN: Added pressure, no. But are the agricultural roots the reason why? Yes.

So, it's my personal belief that all U.S. biodiesel policy started as ag policy, and that's why we have corn ethanol and biodiesel today. And that we wouldn't have a biodiesel industry where 50 percent is made from waste if it weren't for the early soy farmers, who put the money in to getting the biodiesel industry started.

So, those constituencies lobby their state legislatures to adopt pro biofuel policies. And then once those pro biofuel policies were in place, then the market worked out about which biodiesel or which biofuel would enter the marketplace.

So, in Illinois, for instance, they have a sales tax abatement related to the quantity of renewable fuel in the petroleum, whether it’s a gas or a diesel.

And so at a certain blend level it’s just it makes economic sense to do that. Because that was financially more attractive for end users of fuel, sellers of fuel invested the millions of dollars required under the infrastructure to allow the seamless low-cost blending of the fuel into the supply stream.

So, was it ag pushing to make this happen? From a let’s-support-our-domestic-economy, and support and raise the price of our agricultural crops by having them go not only into food, but also into fuel, absolutely yes.

But was that what specifically said let’s put stuff into this terminal and let’s use these fuels? No. Once the policy was established, the marketplace operated to support less expensive ways of getting the fuel into the marketplace more efficiently, and the market developed.

So, the California corollary should be LCFS. And five years from now you and I may be sitting down and talking about how LCFS actually did do that.

Today it’s not the case, so it’s a combination of policies, like AB118, and LCFS, and other things trying to get this whole marketplace going.

And so the message I’m trying to deliver here today is with the AB118 monies, and any other infrastructure related policies the CEC is considering, let’s make sure that -- and, you know, there’s opportunities up and down the supply chain I haven’t mentioned. But the one place that all the fuel has to go through is the bulk terminal, and that’s the one place where no biodiesel or renewable fuel exists today, and that’s where we can get the biggest bang for our buck, and it’s long-term infrastructure that will benefit the State for decades to come.

VICE CHAIR BOYD: Thank you.

MR. BOWEN: So, detropha is an interesting potential feedstock for both biodiesel and renewable diesel. Every detropha project that I personally have had contact with over the last eight years has not met its initial promises.

Will that always be the case for detropha or will someone figure out how to successfully farm detropha so that it can become a new feedstock for either biodiesel or renewable diesel? I will say I’m hopeful that someone will.

And then whether it becomes a feedstock for biodiesel or renewable diesel will simply be a factor of which of those two fuels can most economically compete for that feedstock source, and we'll wait and see how the market plays out.

MR. SCHREMP: Thanks Eric. I have a -- this is Gordon, I have a quick question for you.

Because your company's experienced using -- converting waste material into diesel, could you provide us with sort of some contextual boundaries of supply potential from waste material in the U.S., and from waste material here in California, give us some context?

MR. BOWEN: Yeah. So, we believe the waste available in California is about 75 million gallons of waste feedstocks. Those, obviously, are going into other uses, including export today.

So, what portion of that can you capture? You know, is it 50 percent, 60 percent, 70 percent? You know, pick your number.

The biodiesel plants that are already built in California today, by and large, with really only one notable exception, are built to run waste feedstocks. And, you know, that total production capacity is -- call it somewhere between 50 and 70 million gallons per year.

So, probably right-sized for the feedstocks we have available.

Nationally, it’s a billion gallon plus opportunity on the waste feedstocks. And if -- you know, the one thing about waste that always causes us to pause is, hopefully, waste isn’t growing, so there’s a limited amount of these feedstocks.

And the answer is, yes, there is a limited amount of these feedstocks but, actually, there’s a major new waste byproduct feedstock coming online to the tunes of hundreds of millions of gallon a year, and that’s the inedible corn oil, which is a byproduct of corn ethanol making, and it’s pulled off of the DDGs.

And there’s -- you know, there’s tens of millions of gallons of this product available today. We make a lot of biodiesel from that product, it makes a really nice fuel.

And there’s been recent announcement from POET and others that leads us to believe that there will be hundreds of millions of gallons of new waste feedstock coming to market. So, it is a large available pool of supply that can be used nationally and come here to California.

MR. BRAUTIGAN: John Brautigan, with Valero. Thank you for correcting, I had misstated the number. I had said 600, it’s 800, which even intensifies my concern that the EPA is only showing 300 to 400 million gallons a year rate of biodiesel RINs being generated in this year.

I disagree a little with you on some of your renewable comments. I'm a proponent of renewable diesel. I think we know exactly what the compounds are, they're the same compounds as petroleum diesel. There might not be a spec for ASTMR100, but if you put renewable diesel R5, up to R5, because if you go over R5 you have to have the FTC labeling. But up to R5 can go right into D975. It is -- it's diesel, it can -- Colonial's looking at allowing up to R5 in its pipeline, even though it has jet, where it's got problem with the B.

And I know we're talking with Kinder Morgan, also, allowing R5 in some of Kinder Morgan's California pipelines.

So, there is a possibility that renewable diesel in the future could actually be put in at the pipeline injection point, or by the refinery, or by some -- say -- help me out here -- the Port of Long Beach.

MR. BOWEN: Yeah.

MR. BRAUTIGAN: And avoid the need for some of the infrastructure. But I agree with you that the other problem is we just don't have any infrastructure for biodiesel blending in California, yet we got a renewable fuel requirement for the diesel pool, so that’s one of the reasons why we’re saying it’s hard to come up with something that you want to take to the bank and say this is how we’re going to comply.

MR. BOWEN: Yeah, so I appreciate those comments, John. Taking them in reverse order, you know, Colonial you mentioned, they’re also the pipeline company that’s doing all the work on biodiesel, as well as renewable diesel in the pipeline. Kinder Morgan has also been doing a lot of work for both biodiesel and renewable diesel in the pipeline.

And I agree with you that the concerns about any contamination with jet, with the renewable diesel, no concerns because the cold flow properties are so impressive with the renewable diesel.

My comment about not knowing the compounds is more directed at the stage of development of renewable diesel. I mean, hydro-cracking is well known. But if you’re using Neste’s process, or UOP’s process, or someone else’s process, and then you’re using a palm oil versus a tallow, versus a used cooking oil, versus a soybean oil, all of those things look different, at least based on the conversations that I’ve been having with UOP and others.

And it’s not that they’re bizarre, it’s just that they’re not yet well known, they’re not yet standardized.

As you mentioned, ASTM is working on this and there are different opinions on how that’s going to come out.

So, by and large I agree with you, just wanted to clarify that point.

Then coming to your point about your concern about RFS2, you’re absolutely correct that the January and February volumes would send a signal that we’re far short of the 800 million mandate.

A couple of reasons that is the case; one, you now, as you’re well aware, there was the petroleum industry’s lawsuit against the RFS, which only was resolved in December, so there was a lot of holding back of demand by obligated parties, and others, pending resolution of that lawsuit. So, it takes people several months to sort of ramp up to begin buying and incorporating biomass-based diesel, and biodiesel, in particular, into the fuel supply.

I think you’ll see the March and April numbers is significantly higher than those January and February numbers.

I think you’ll still see the run rate at a place that would be disconcerting that we can make the 800 million gallon per year mark without having a lot of catch up in the back half of the year.

We're having conversations with EPA about this and whether or not it makes sense to require obligated parties to report quarterly, rather than annually, so we can spread out demand more evenly throughout the year.

There is sufficient feedstock, there's sufficient production capability. And nationally, a lot of the country looks like California and there isn't good infrastructure. So, trying to get fuel into the southeast, into other areas of the country where we could have more volumes to more easily achieve the 800 million gallon per year mark is more the issue, an infrastructure issue, than it is a fuel availability issue.

So, I do think we'll get reasonably close to 800 million gallons. We may fall short but, you know, with those infrastructure investments coming in we should have no problem meeting the billion gallons next year and then going higher thereafter.

MR. BRAUTIGAN: My only comment was I think what you're going to find in the next several months, the only -- the components from the different renewable diesel processes are getting more and more defined.

It’s basically is it a C14, 16, or 18, or 20 hydrocarbon chain, but they know -- they know what’s being produced by all those process from pilot runs, or in Neste’s case, actual runs, they actually know -- they know the molecules.

MR. BOWEN: Yeah, and again, I want to make it clear, I’m a proponent of renewable diesel, it is a product that my company will almost certainly make when we think the time is right.

The point I just want to reiterate is the one you made, and I want to make sure the regulatory community is aware, ASTM and other key stakeholders haven’t gotten to the point where there is a standardized definition of what is renewable diesel.

So, you’re talking about hydro-treated renewable diesel, that’s the one there’s the most clarity.

There are Fischer-Tropsche renewable diesels, made from biomass. There’s special bug renewable diesels, made from processes like amyrises, which are using sugarcane and going through, you know, biological processes, all claiming the title of renewable diesel.

So, we need to figure out what is renewable diesel and how it’s going to be dealt with.

Quite frankly, we would like to participate in all three of those types of renewable diesel, we think they all have a role to play. We just need to be clear what we're talking about when we use the term renewable diesel.

MS. GREY: Gina Grey, from WSPA. Sorry, I'll make this quick, hopefully.

Eric, I think you very accurately said that in terms of B5 and the potential NOx impacts, that the National Biodiesel Board, and WSPA, and the Engine Manufacturers Association currently are in dialogue with ARB to talk about their supposition, at this point, that there is actually a NOx bump from AB5 level, which I think our three organizations at this point in time don't necessarily agree, we're looking at the science and the test data.

I think the point that I would probably disagree with is in terms of the characterization that if, in fact, there are issues there that we could just put in additives, or it can quickly be resolved.

And I think in our viewpoint, anyway, at this point in time that those mitigation options that have been offered up by ARB are not necessarily either the correct way to go, could be costly, could have other environmental impacts, et cetera.

So, I guess my one question here is in terms of the aquatic toxicity issue, which you also kind of went through, that obviously was raised by ARB on December 8th, when they had one of their contractors come forth and say that in their estimation there was some aquatic toxicity issues. And that's all part of the multi-media assessment that takes place in California.

He discussed the federal effort to look at those types of USDA issues, and everything else.

But just curious about how you foresee this all playing out in California, where we have our own process here, you know, the Environmental Quality Commission, or whatever it's called, that needs to look at all those types of issues, and whether or not this aquatic toxicity issue could be something that's of concern and that actually prevents biodiesel from coming into play in California, in the volumes needed, without exemptions, or other variances, or other things.

MR. BOWEN: Well, thank you, Gina, for the reiteration and clarification on some of those points and the question.

So, you're absolutely right, we all believe B5 does not have any NOx increase that the ARB's just looking at the data the wrong way. And I definitely didn't want to leave anyone with the impression that there's an easy additive solution, it would be a headache.

I did also want to say that as you get into higher blends, where we acknowledge that with some biodiesels there is a NOx increase, we believe we will be able to find solutions for those fuels so they can participate in the marketplace, and/or just have certain types of biodiesels that are naturally high in cetane.

With regard to the aquatic toxicity, I have seen those reports. We're going through, under the review, trying to figure out exactly what that is. And we consider ourselves, and have from day one, to be an environmentally beneficial and friendly fuel, biodegradable, reduced air emissions across all regulated emissions, with the notable exception of NOx, as we've been talking about.

We have not yet had a chance to get through that and respond to ARB about what we think that means from multi-media. We certainly appreciate the effort that they're going through and think it's necessary and appropriate, so we'll address that when we can. Thank you.

VICE CHAIR BOYD: Thank you, Eric.

MR. WENG-GUTIERREZ: Okay, thank you, Eric, that was very good. It sounded like there was lots of conversation there, very good, but it did put us a little bit behind schedule, a little further behind schedule. I thought we were doing great there for a little while and then all this conversation happened, which is great. We don't want to prevent that from happening, but we are then now a little bit over 30 minutes behind schedule.

So, with that I'm just going to ask Gordon to come up and do his presentation, and he'll be MC'ing for the rest of the day.

MR. SCHREMP: Thank you, Jesse. Thank you, Malachi. Thank you, Eric, that was a lot of good information.

Are there any questions on my presentation? I'm just trying to speed things up here.

(Laughter)

MR. SCHREMP: Well, you guys have the slides. All right, I'll go through them rather quickly, I'll do my best.

VICE CHAIR BOYD: We know better than to ask you any questions, Gordon.

MR. SCHREMP: Yes. Infrastructure is very important. I think Eric allayed some of the issues, especially in the bulk terminals, on the diesel side, undoubtedly on the biodiesel renewable diesel side.

So, what we look at is more than just in California, because the whole system is distribution terminals, over 50 of them, pipelines, interconnections, refineries, and all of this, but we are looking at a multi-state demand.

As Malachi mentioned this morning, we look at Arizona and Nevada because we provide nearly a hundred percent of Nevada’s fuel and upwards of 50 percent of Arizona’s fuel.

This is going to change a little bit and I’ll talk about that in just a minute.

But, so we do demand forecasts for Nevada and Arizona, gas, and diesel, jet fuel. We also do renewable fuel forecast for those states, the same thing analogous to California, sort of a post-processing, we will look at RFS2 fair share compliance.

And we will further assume, as was mentioned earlier, Arizona will have an E10 cap over the forecast period, and I think we’re considering doing the same for Nevada.

So, love to take people’s comments on those assumptions.

So, demand forecast in Arizona and Nevada, why is that important? Demand goes up, more will be wanted to come out of California through the pipeline system. Demand goes down, the converse. So, that’s important, that’s why we look at it.

This is the interconnected system, just to demonstrate that Arizona gets fuel from the West Texas refineries and that volume, especially on the gasoline side of the ledger has increased over recent years, and the black lines are representative of petroleum product pipelines.

But it should be noted, no pipelines coming into California, it just leaves, because we're a net exporter over pipelines.

So, we look at an incremental approach, how much more or how much less barrels of petroleum products and renewable fuels? So, that's sort of how we do the demand forecast.

And we also look at, as I mentioned before, neighboring states and the fuel systems, including renewables. The new element is the Utah to Nevada pipeline, a petroleum product system that is near completion.

And this is the existing pipeline infrastructure. I think the map has -- I have to update this portion, there's only one line, petroleum products cannot be transported from -- essentially, they can no longer, I think, go this way, there's only one direction.

So, the products coming from the West Texas are dropped off here and then can continue on to Phoenix and the west, but there’s no ability to move from Phoenix the other way, except by trucking, of course, and the pipeline system up to Las Vegas.

So, the new pipeline is coming from the Utah refining complex all the way down into Northern -- Northern Las Vegas.

So, this is expected now, I believe the update at their quarterly meeting, just recently, is later this summer it will be operational capability of the system. So, it’s lagging just a little bit from the information in this slide.

The initial capacity is still thought to be about 30,000 barrels a day. Half of that will be delivered to a terminal in Utah that product is currently being trucked to. So, that supply already exists, now it’s being a pipeline, a little bit safer means and less costly means of transportation.

The other portion, 15,000 barrels, that we’re not quite sure how that will be split between gasoline and diesel, will go into Northern Las Vegas. Now, that’s a modest amount, but it will affect our outlook for the neighboring state. And there is a potential to expand in the future on the pipeline’s capacity.

However, the limiting factor is likely adequate excess barrels available from the starting point in that system and that's the Utah refining complex, as well as the ability to get products into that system. At times that's a market that can be short on supply, so we're not assuming that it's going to be 50, 60, 80 thousand barrels of spare supply to go into Northern Las Vegas.

Marine oil terminal engineering and maintenance standards, or we love to use acronyms, MOTEMS. This is very important, this regulation as part of the Business Code is proceeding. All of the assessments and safety Is have been completed on the highest risk, marine oil terminals, and which are basically all of the ones that are utilized in California, in Northern and Southern California.

And so now it's in the discussion phase, the most important level about, okay, when are these upgrades going to begin?

And in Southern California, especially, the tenants of all the terminals are under lease agreements, they don't actually own the property, and that is a different dynamic from Northern California.

So, what we're seeing is that those with lease agreements, that are nearing expiration are, you know, in discussion about will they move forward, will they be renewed? If they are, co-paying, co-sharing the cost, the Port doesn't carry all of the bill or all of the bill. So, these are underway and an important consideration because the Port will actually look to the IEPR forecast for whether or not all of these facilities need to be upgraded, this is especially the case in Southern California. So, they're paying close attention to our forecast for crude oil imports, as well as transportation and renewables.

Now, what may be missing from all that dynamic is how spare capacity may be viewed by the people involved in these negotiations. And whereas we don't look at a marine terminal as a steady state operation, like a base load, you know, electricity producer, we look at that as having to need some spare flux in there because of the indeterminate nature of the arrival of marine -- of marine deliveries. From time to time it's not as precise as other conveyance means.

As well as the sort of intermittent need to temporarily move more product through a particular oil terminal because of an unplanned refinery IRG.

And a final point of why just looking at spare capacity may not be the correct dynamic to view these terminals is the potential closure of a California refinery that, you know, two years ago, four or six years ago was sort of unheard of in our sort of thinking ahead, but now is a much more, I think, realistic scenario based primarily because of a significant decline in gasoline that we forecasted two years ago, and as well as this go round, we anticipate.

So, we're looking at capacity, we want input from stakeholders on what the outlook is for these projects and what the needs are.

And so, you know, once again we're here, we've a process, we want input, we want input of the docket, to be better educated on where we're going. But we do recognize that the stakeholders do wait for us to put out a forecast, and the draft report to comment on. But there is probably some valuable information, they could provide insights to us prior to that -- that time.

So, distribution terminals, ethanol and biodiesel are delivered via primarily tanker truck. I know Eric mentioned we'd like to have rail. I think, yes, so would they. A lot of those rail spurs have been gobbled up, development has encroached upon a lot of these distribution terminals, so that's pretty problematic at this point.

So, it's biodiesel, it's drop-in hydrocarbons as Eric mentioned. Renewable diesel imports via rail car, how do you get them? Is it transloaded to tanker trucks? You know, what are these issues, including renewable and natural gas, and that was discussed earlier this morning, and that infrastructure. Getting into that infrastructure, what are some of these limitations and challenges that we need to be aware of and to see what -- you know, how some of these barriers can be overcome.

So, those are my slides and somewhat brief for me. Any comments?

VICE CHAIR BOYD: Thank you, Gordon, I wouldn't dare.

MR. SCHREMP: Okay.

All right, I'll hand the microphone off to Matt Tobin, of Kinder Morgan.

MR. TOBIN: Thank you, Commissioners. And thank you, Gordon, I appreciate the opportunity to come and speak with you today.

I'm actually speaking on behalf of Kinder Morgan Terminals. Pipeline infrastructure obviously here, in California, is the major asset base, but we do a little bit of business in a different way across the U.S. I'll talk a little bit about the market and talk a little bit about what Kinder Morgan is doing in a general sense and what we're doing here in the State of California.

The ethanol industry over the last number of years, especially from a distribution infrastructure perspective has really matured. There's been a lot of work, a lot of capital spent on various areas of development across the U.S. to support the RFS2, to support what generally is a ten percent mandate across the U.S.

So, last year there was sort of a 12.5 billion gallon consumption level for ethanol within the U.S. as a blend component.

This year we'll probably be closer to 13.3, when it's all said and done. Running about 9.4 percent right now, the gasoline pool is ethanol, so it's inching up to toward what they call the blend wall, right around the 14 billion gallon level.

From a terminal perspective, because we're heavily engaged in the distribution of gasoline throughout the U.S., we spent a ton of time and effort on trying to get this right for our network. A lot of effort in the New York Harbor, all the way down into Florida, the Chicago market, Houston Gulf, and in California, in particular. We probably have 70 plus terminals right now that are handling ethanol in some form or fashion across the U.S.

And that's, obviously, necessitate a large investment in our tank infrastructure. We put in place right now, just over the last couple of years, nearly five million barrels of storage capability across the U.S. All of that has been kind of incremental, year over year as we go, just trying to keep up with our customers' demands on making sure the product is where it needs to be at the right time.

And it has a wide variety of capabilities across the system as well, we just have to keep up.

California was a little bit unusual in that there was a huge amount of demand and, actually, the first big ethanol unit train operation was developed here around the 2002-2003 time frame in Lomita, what we call the Lomita rail terminal, in the L.A. Basin.

And what that does is it's hooked up to Shell Carson, and trains come in either 96 or 112 car, they're unloaded into the pipe and sent up in the storage, and then distributed out through the Carson rack.

That model was emulated pretty much across the country and between the New York Harbor, our couple of big developments out there, or course, in the Gulf, Chicago area, that has been the way that -- has been the way to go.

Within California other developments of that nature are difficult. It's very difficult to permit, it's very difficult to get the storage space to be able to do this, it's very difficult to get the railroads to cooperate, et cetera, et cetera.

That being said, we have essentially five unit train facilities here in California. One, as I mentioned, in Lomita. The other in Colton, California, which is just out around Riverside area. That's not a true connected pipeline operation, yet, but it's got unit train transload capability.

We run the same kind of facility up in Richmond that was put in place in March of last year. They're able to take a hundred-car trains in there and distribute it out via truck.

Selby is really more mature, it's able to have some marine capability there.

And Stockton, depending on what happens with Pacific Ethanol, can be in the storage and distribution business. Right now it's a very difficult situation with the price of corn to be -- to be in the destination production infrastructure business, and they're working through that right now.

I should mention this, Gordon asked me to talk a little bit about assets outside of the State of California that could have an impact on how product is distributed here.

We have, over the last number of years, sought to develop a facility in the Houston area. This one was put up just in April of this year. We have the ability to take hundred-car trains and to put it into storage, and generally for the Houston market, the greater Texas market.

But what really drove this opportunity was the fact that we had a big spot on which to land trains and an even bigger spot on which to land product.

If you look over on the left-hand side of the screen, that's our Pasadena facility, between Pasadena and Galena Park we've got about 25 million barrels of storage, and Deer Park has about 1,200 rail car spots.

We connected the two via pipe, with the idea, potentially, of using this as a spring board to satisfy LCSF demand. The reason being rail infrastructure here is such that you can take product, we can actually load trains, our Brazilian product, that would find their way into the Houston market and then send them out to the West Coast.

And the reason being is that the whole idea, there's been a lot of talk about Brazilian product, and Brazilian product coming into the States, and it's had a generation, I guess, a couple of C changes in it. Brazil was generally the source of the world's ethanol for quite some time. Now, because of their own domestic demand, it's very difficult to find the right amount of product to send out.

The California demand, more or less on an annual basis, 1.5 billion gallons. The total exports out of Brazil are something less than 900 million gallons, and in 2009, much less last year. It's to the point right now where Brazil is so short ethanol that we've taken on the -- through the Port of Houston, sending ASTM grade down to Brazil as imports for Brazil because they're short of their product.

I mean, over the last number of the years, they're getting to the point right now, I guess by 2012 UNICA says that they'll have 50 percent of their automobile fleet will be fully flex fuel capable. And they'll have either an E25 blend or an E100 blend.

Last year, because they were short ethanol and there was a little bit of a drought, they knocked it down to E20 and they actually had to import gasoline to make up the difference.

Now, because of the price of gasoline worldwide, they've elected to import their ethanol to be able to make grade.

They have some very, some difficult specs for a lot of U.S. terminals because it has to be DSP compliant, it has to go out as undenature. But in this case they were so short they said we'd take ASDM grade, flat out.

So, a very interesting situation and it’s a little bit problematic, I guess, from a distribution stand point. Even in the best of circumstances, if you could take Brazilian product out of, let’s say, Santos and move it up through the canal, and move it up into the West Coast of the U.S., you’re looking at vessel sizes approaching 300,000 barrels and that kind of lands with a thud on the West Coast. It has to hit -- it isn’t that you would be short terminaling capacity necessarily, per se, it’s just that you have to have the space and the capability to be able to take in 300,000 barrels at a time, which is about what those vessel sizes are.

So, invariably, what would happen then is that vessel will have to multi-port its way up across the West Coast and have those economics work, which is it’s a little tricky.

Our thought in using Houston as a spring board is to go to the Brazilians, which we’ve done, and said, look, it’s a five-day milk run up to the Gulf Coast, send product up there, you can put product in storage with Kinder Morgan. We can take that product, if we need to segregate it, if we don’t -- I think we don’t, has long as -- we have to demonstrate a pathway, according to what CARB is telling us, and we can send product out to the West Coast, use all the existing infrastructure, and have trains out of Houston to Lomita, Northern California in four to five days. That takes it out of -- that takes the pressure off of the supply chain a little bit.

But in the best case coming out of Houston, I mean we could probably do a couple of trains a month, four, five, six, eight, maybe. You’re looking at demand here somewhere in excess near 100,000 barrels a day of ethanol coming in. So, it’s a huge challenge, logistically, to make all this happen.

Just a couple -- I told Gordon I’d give him a couple of words from our products pipeline side, on kind of where we’re seeing the pipeline issues now, and especially with regards to MOTEMS.

We are being -- we’ve had our lease non-renewed in the Port of Los Angeles or the Port of Long Beach, so we’re going to be leaving there this year. We probably would have had a MOTEMS obligation, but as a result of our leaving it no longer exists. We’re looking for other alternatives right now.

UNEV, it’s a little tricky. I think Gordon was spot on, it’s hard to tell right now, but there doesn’t appear to be a huge over-supply of product in the Salt

Lake City market that would need to find its way down to the greater Vegas market. It’s hard to tell right now.

The economics we that we saw in coming into the pipeline, it led us to believe that the refining economics were really driving this. This is something we don’t do because we’re not in the refining business, necessarily. But there may be other reasons for making that -- this go.

We don’t see a huge amount of product that would have otherwise not gone into Vegas via the CalNev line not going now. But it remains to be seen. As Gordon said, I think they’re due to be up the third quarter of this year. They have a couple of terminals I think already up and going, so we’ll see how that works out.

One of the other things he asked us to comment on was the Longhorn pipeline. There is talk, now, that Magellan, who bought Longhorn from Flying J would elect to reverse the direction of that line and send crude product out of the Permian Basis back in the Houston area. And, traditionally, Longhorn has always run refined products out, made its way to El Paso, and El Paso has then taken it on to the west.

I’ll tell you, it’s very difficult right now to imagine them not wanting to reverse it. The crude oil demand in Permian Basis, in particular, at, you know,

$90, $100 crude really favors them pushing product into the Houston area.

Likewise, there's been a substantial amount of development in the Eagle Ford Shale that will allow for crude to make its way, again, in Houston refineries, at really attractive numbers.

So, within our shop and I know within a variety of others, midstream players, like Kinder Morgan terminals, we're looking at crude really hard right now, and infrastructure around the -- development of infrastructure around crude is almost a mirror image of what happened with ethanol a couple of years ago. You could see terminals here and we've actually been approach to look at terminal developments for crude oil coming into the State from various places, like North Dakota, or others. So, very interesting circumstance.

My contact information is up here. And Jim Kehlet really runs the pipeline side, if you have any questions on the pipeline side, he's over in Orange, California.

Questions?

VICE CHAIR BOYD: Thank you. Any questions? Gordon? Anyone? All right, thank you very much.

Oh, Gordon, you do have a question, I was unclear.

MR. SCHREMP: Well, thank you, Matt, you kind of left us hanging there. It’s like Paul Harvey, I’d like to know the rest of the story.

You said your operational marine terminal in Southern California which is, I understand, connected to your Carson Tank Farm, you have lots of clients in there. You’re looking for other alternatives and, clearly, that is code for pipeline connection to the water so you can still utilize or your customers can still utilize those tanks.

So, my question to you is that for the sake of argument, yeah, you will keep pursuing this and ultimately be successful, would that increase or decrease the through-put capacity of Southern California ports, losing your terminal?

MR. TOBIN: That port, it did some very specialized things, and it did some very good California things and did some expert as well.

And the answer is right now I don’t think we’re sure. I wish there were a lot of very easy things that we could look at, but everything that we’ve looked at is really expensive.

That being said, I know my guys in Orange are working very hard to put ourselves in a position to be able to do something beyond 2012. Yeah, we’re going to have to look at different ways of doing business if we don’t have an outlet there.

MR. SCHREMP: Thank you very much, Matt.

And I’ll hand the microphone off to Jim Iacoponi, from Propel. Jim.

MR. IACOPONI: Thanks. Thank you, Gordon, Commissioner. Good afternoon, everybody.

A lot of the conversation’s been quite at the macro level here. I’m going to do two things, I think, differently. First is I’m going to bring it down a little bit to the micro level and share some experience that we’ve had recently, as much about a product opportunity for the State of California, but also as a little vignette about our experiences in working our way through the State.

I’m sure no new learnings for most of the people present, but it just sort of may bring to home opportunities.

And the second thing is I will have brief comments so, hopefully, that will help get things a bit back on track.

One of the things that my team does, we’re the operations folks for Propel, we do is look for opportunities to bring lower carbon and renewable fuels both into our own system, into the State and, also, at the end of the day we’re really in the business of matching product fuel opportunities with customers.

And last -- last fall we were approached by a couple of producers with the potential to introduce into the State of California a new product, renewable diesel, now being produced at commercial scale. So, clearly, we wanted to take a look at, well, what is this? Is this anything that would be allowed by the State? Is this anything that would have customer interest?

And I think Eric did a great job of framing up what the market realities are. Transporting fuel is expensive when it’s not produced here, locally, and the cost of handling, actually, puts it -- puts it in a place where customers have to be quite interested in the environmental benefits to consider it as a fuel and a replacement for either diesel or for biodiesel.

I think when presented with the specs that are on here we were really surprised and also, I would say, delighted at the opportunity for the potential environmental impact that such a fuel could bring to both the customers that we were speaking to, but also to the State of California, and particularly in the non-attainment areas.

You know, I won’t go through and read them all, but I think that the upshot is that when you look at a product spec for a real product being made today available in commercial quantities you say, okay, number one you get huge environmental benefit and you can get it immediately.

I think the second is that for the customer, and certainly at the customer level, they don't need new equipment. They, at the customer level, don't need any particular storage changes. They don't need to be thinking about putting in large tanks, pressure tanks, they don't need to be overhauling diesel systems, they don't need to be thinking about any of the maintenance changes for replacing, converting to, say, a compressed natural gas, and they can get benefits immediately, and they can bring their region benefits immediately.

And so with that thinking going out in the market in fact, despite some of the cost challenges, we found customers that said, yes, this would be a phenomenal opportunity for us, can you get the State to agree.

And we said, you know what, our job is to actually bring you and this opportunity together and we are happy to take on leadership in working with the State.

I think that where we are today is at the higher level, so renewable diesel and, again, the point is that renewable diesel has multiple flavors, it has multiple definitions. What is approved by the U.S. EPA? At what level, is it a hundred percent blend, is it an R20 blend?

Currently, this particular product could be used and is permitted at the U.S. EPA level at an R20 level. And there is a pathway to get it through to an R100 level. I think that's good news for both the customers who are interested and, clearly, the environmental -- the environmental benefits.

When we work through the different hurdles what we find is that actually the lack of definition of what this product is runs into the familiar can it be stored underground in the State of California?

When we look at -- when we look at its specifications we've got a sample, we've had it tested a number of times. You line it up next to diesel fuel, the people that we speak to, and we've had, I would emphasize, within the Energy Commission, the Water Board, and the ARB, just phenomenal support by staff.

When we take these specifications to staff they say, we can't tell the difference. But it doesn't meet the regulation as it's known today and so one runs into a bit of a hurdle.

I think it was also very well brought out, earlier, that at the bulk level the bottom line is to make fuel economic for customers. While they may be willing to pay some premium for environmental benefit, to meet corporate goals, to be -- to also state and local governments to help meet local attainment goals, there may be some premium that is affordable, but that is not affordable without sufficient quantities being moved, being stored, being transloaded to help bring down those infrastructure costs.

And so, current hurdles to real successful implementation, in addition to the first two, really lie in this notion of what bulk handling and storage infrastructure will be available and how might fuels, such as this, take advantage of it?

And I think then, at the last, with anything new there isn’t a lot of public information that supports the magnitude of the environmental benefits that one would expect to get from the product, such as this when you look at the specifications.

And, you know, so in this State it strikes us that this is a real opportunity for a public/private partnership to conduct testing, to really understand the nature of a fuel such as this.

Which really then leads me to this slide, which is what I wanted to share. The questions that I’ve put on this page really describe a journey of about nine months. And you go down a path, and then you go down the next path, and then you go down the next path. To encourage a producer to make an investment, to encourage product investment in product storage and handling along the way and, actually, at the end of the day to encourage customers to want to sign up for a new fuel, all of these have to be gone through.

And, therefore, and it’s not -- it’s not just answering the questions, what we need is the confidence, through written communication that can go back to producers, to handlers, to customers to say there is a fuel, we can actually take your demand and match it with your supply, and bring together change for the better for the State. Hence, the last line “can we get this in writing?” Which is -- which is always interesting but, again, we’ve made some good progress.

How can you help? I think, very simply, consider whether or not there couldn’t be a single point of coordination amongst the different State level agencies to help clear implementation hurdles for new fuels. We’ve had conversations not just in the diesel space, but also in the renewable gasoline space, and everyone within the State and outside the State asked the same questions; can I sell this to anyone and what are the hurdles of getting there?

And so, getting help with that would be -- would be great.

Secondly, I believe, Propel believes that a coalition of agencies to understand what would a coordinated set of tests look like for air, emissions, and also to meet some of the other questions that might come up with regard to energy efficiency.

Can there be, again, a single point that says this is an appropriate testing program and then help with companies looking to put their products into this testing program.

And I think the last is just recognizing that at the end of the day the pace at which programs move, particularly the pace at which test programs, or fuel approval programs move is really what allows a market to be developed.

And what California wants is to develop the market for renewable fuels. Sometimes they might be segregated products, sometimes they might have particular NISH applications to encourage producers to make the investment, to go through the process on permitting if there’s a way to stimulate demand in advance through small, one-off projects and, again, small companies such as Propel can certainly work in this space, that kind of support, moving at pace with your continued interest in supporting storage and handling investment would be great. Thanks. And those are my comments.

VICE CHAIR BOYD: Thank you. I guess I showed my hand of interest earlier in the day, so you've posed a lot of interesting questions you're to pursue.

Any questions from folks?

Gordon, did you rise for a question or are you just --

MR. SCHREMP: Thank you.

VICE CHAIR BOYD: All right, thank you very much.

MR. IACOPONI: Thank you very much.

MR. SCHREMP: Thank you, Jim.

Chuck White, from Waste Management, is our next guest speaker.

MR. WHITE: Good afternoon. I can get started while we're getting this set up, as long as I don't have to go on too far without my Power Point slides, which I'm always a little bit having to rely on.

I'm the Director of Regulatory Affairs for Waste Management in California, and Western U.S. I have to say, it feels as though I'm a little bit out of my league with all these experts in the field of fuel and energy. I’m a waste guy, so I hope you’ll bear with me if I don’t -- if I demonstrate my ignorance.

But I really appreciate the opportunity to be here to talk about some of the things that Waste Management is doing in developing fuel platforms to serve our needs.

And starting off on this chart, of where I’ve titled this slide “Closing the Loop on Transportation Fuels” and I hope that will become clear why I chose that title, when I get through this brief presentation.

Now, you can see the five pictures up there kind of portray what Waste Management is. We’re a 12 and a half billion dollar revenue per year company. We have about 45,000 employees.

Our principle, where you see us in activities, is collection and transfer of waste and recyclables. We have 20 million customers in North America. We have 367 hauling companies around the United States, and we have 19,000 heavy-duty trucks in North America.

So, we basically are a transportation company from the collection and transfer.

We’re also a disposal company. We have 273 landfills, and those landfills are basically big, anaerobic digesters that generate a lot of methane, which is both a good thing and also a bad thing, depending on how that's managed.

We're the world's -- we're North America's largest company of collecting recyclable materials and we're also getting to view ourselves more and more as a renewable energy company. I didn't used to come over to the Energy Commission very much about three or four years ago, and now I find myself over here almost weekly on a variety of issues that are directly related to the services we provide.

Here's a picture of a map of our 367 hauling districts in North America with our 19,000 heavy-duty fleet. Each dot represents anywhere from five to over a hundred heavy-duty vehicles. The average fleet size of each of those dots is 50 heavy-duty vehicles.

Nationwide we only have about -- well, this says a thousand, we have about 1,200 natural gas trucks, about five or six percent of our total heavy-duty fleet, but that's changing rapidly.

In the west group, where I mostly do most of my work, we've got 5,000 heavy-duty vehicles in these states. We're focusing, really, in California, a little bit in the Seattle area. We're generally converting our fleets over to natural gas, both CNG and LNG. We have five CNG fueling facilities now, we have ten that are in the development process, handling about 500 trucks in the west. We have nine bio-LNG facilities, where we bring both natural, fossil-LNG and bio-LNG that we produce at our Altamont bio-LNG facility near Altamont Pass, in Northern California. That produces about 19,000 gallons a day that we distribute to these nine bio-LNG facilities. And we're in the process of developing five LCNG facilities, so we can both use liquefied and CNG for fueling our trucks.

Waste Management is really in the process of converting our entire fleet. We're ahead of the game in California, about 31 percent of our fleet of 3,200 trucks is LNG or CNG, and we're doing everything we can to convert our fleet to natural gas as fast as we can.

Our goal is that 80 percent of our new heavy-duty vehicle purchases will be either LNG or CNG platform trucks. We would do even more, but it -- and I say it's a goal because we still have the fueling infrastructure problem. Fueling infrastructure is the biggest problem facing us because these fueling facilities cost anywhere from two to three million dollars for the fleet size that we're talking about, in addition to providing public access where that's possible.

So, it's a huge cost and that is the big barrier in doing even a faster conversion of our fleet.

And looking at the carbon intensity of alternative fuels, one of the many reasons we've chosen to migrate to natural gas or renewable natural gas is it's a two-step process. The first step is converting to fossil natural gas, but the second step is once you get onto the natural gas platform, it's easy just to convert over to renewable natural gas as your fuel.

As you can see from this bar chart, the bars on the left are ultra-low diesel, following by B20 and B100. You can get the same carbon reduction as B20, biodiesel 20, simply converting over to fossil natural gas and fossil -- either fossil CNG or fossil LNG. But if you make the next step to biogas, you can get as much as a 90 or more percent reduction in your carbon intensity.

Where do you find biogas? Well, believe me, it's everywhere. It's available at landfills, it's anyplace where anaerobic digestions going of animal food, sewage, and crop wastes. Waste Management is focusing on landfills because, why, we have a lot of landfills, and there's a lot of potential for development of unused, un-beneficially used landfill gas to create energy and biomethane.

The next area we're looking at is the unused capacity of sewage treatment plants, where they have anaerobic digesters, where we can divert food waste from landfills. There’s a big effort in California to focus on food waste diversion. We have a proprietary process to process food waste, to separate any plastics, and glass, and metals in that and basically put a product that can then go right into an anaerobic digest, or a POTW. They’re already built, they’re already constructed, the capital investment is already there, they just need to be retrofitted with something to capture the gas to turn it into a fuel that could be used to fuel our trucks.

So, we’re really looking at a wide variety of different ways that we can take advantage of the anaerobic digestion process that’s going on all around us.

Very low greenhouse gas emissions, just the lowest that’s available in California, DOE estimates that about 10 billion gasoline gallon equivalents per year are available to basically displace 90 million light-duty vehicle equivalents from the roads and throughout North America.

Natural gas is really the high -- is the low-hanging fruit. It’s from the anaerobic decomposition of organic waste in a landfill. Gas is about one-half percent methane -- one-half methane, one-half carbon dioxide, with some nitrogen and oxygen, and additional impurities that need to be refined out.

As it comes out of the landfill it’s a medium BTU gas, we’ve typically used it to bear in engines and turbines to generate electricity. We’re running up against problems on air emission standards throughout California and so that was one of the many reasons why we decided to look and explore ways to generate fuels, instead of electricity.

Here’s an LCF lifecycle assessment of landfill gas to LNG, for example. If you take a look at the landfill, you collect the gas, it typically would go up into a flare. It’s required to be flared, required to be burned, you just simply can’t discharge it to the atmosphere.

There may be some fugitive emissions, but if we can divert the gas away from the flare into a fuel production, into transportation and fueling, and then the pump to wheels at the end, there maybe are some emissions along the way.

But in the case of fuel production, if we can use the energy for the fuel production at their landfill to be generated by biogas, then we’re also further lowering the carbon intensity.

And so this is basically you’re displacing gas that would have otherwise gone up into a flare, you're redirecting it into a fuel and it displaces fossil fuels with -- to a very low carbon intensity.

Here are the carbon intensities I borrowed from the LCSF, they're the most recent, some of the most recent numbers that are up there. You've got the fuel type on the left, direct well to wheel emissions, indirect emissions, total emissions, then the percent of emissions relative to diesel.

And the red is gasoline and diesel and you can see that's the big kind of the baseline we're trying to provide a reduction from through the low-carbon fuel standard.

Ethanol, all the ethanol ones that are currently posted are all crop-based ethanol. You can get down, even some of them, like Midwestern coal is a higher carbon intensity than diesel or gasoline. You can have some reduction in ethanol.

You can even get further reduction in ethanol if it's waste-based ethanol. There aren't any pathways for that right now in the low-carbon fuel standard.

Getting down to lighter color yellow you get the biodiesel and you only really get the real reduction in carbon intensity from biodiesel if it's a waste-based biodiesel, like waste cooking oils, waste corn oil, waste tallow.

The green at the bottom is where we want to end up, is making the transition through step one to CNG or, potentially, LNG, from fossil sources, about a 70 percent reduction -- excuse me, a 30 percent reduction in carbon intensity, but to really make this next step into renewable CNG, renewable LNG, with even -- even much greater reductions.

And these default total emissions levels that are produced by CARB, are the low-carbon fuel standard, are based on the assumption that the electricity used to run the power plant, run the refinery at the landfill is from the grid.

As I indicated previously, we'd like to make sure that we provide electricity that is a biogenic source of landfill gas, for example, and you can get even a further carbon reduction down to maybe five percent in the range of diesel.

We think we can even do better than that by, and this chart tries to portray that. It's kind of similar to the chart you saw before, but rather than using landfill gas, we would intercept the waste before it goes into the landfill and divert it over to a conversion technology type of facility and produce a gas, either a methane, or a syngas that would go into fuel production, to transportation and then, finally, the pump to wheels process.

The benefit of actually intercepting the waste before it goes to the landfill is you might get a further carbon reduction by reducing fugitive methane emissions from the landfill because you're intercepting the waste. Instead of going to the landfill and generating gas that's collected in a flare, but also generating gas that's fugitively emitted, you avoid the fugitive emissions.

And we're interested in seeing if CARB will take a -- will recognize this as a legitimate source of carbon reduction in those kind of fuels that are based on waste that are diverted from landfills, and going into a conversion technology process.

What you can actually end up here is a fuel with a carbon intensity that's less than zero. You can -- if you start off with 95 grams per mega joule, you may get 120 grams per mega joule reduction, so you're actually in a negative territory in your overall carbon intensity.

You're not going to find any fuel that has a lower carbon intensity than a waste-based fuel that's based on diversion of that waste from a landfill.

Waste Management has partnered with Linde and the Gas Technology Institute to build the world's first and largest commercial landfill gas to LNG plant. It's a $15.5 million plant, it's not cheap. It's 13,000 gallons of biodiesel per day, about five percent the carbon intensity of diesel.

We have a second plant planned for Southern California, with the assistance of this Energy Commission. The first plant at Altamont couldn't have gone forward without about $2 million in government grant funding from the Waste Board, CARB, the Energy Commission, and the South Coast Air Quality Management District. It's the largest effort to introduce on-site liquefaction for landfill gas in North America.

Here's the design of the facility. Are there are any questions about how this process works?

(Laughter)

MR. WHITE: Well, if there are, you're going to have to talk to the Linde Group for details because they really were the experts that brought on the technology to make this happen. The bottom line, it's complicated.

Some of the challenges we had were aligning these multiple-unit processes, there's about five or six unit processes that are all combined together, in tandem, to provide the overall treatment and it required, really robust design and commissioning to go from 50 percent methane to a final product that has 96 plus percent methane.

Having to reduce CO_2 from 50 percent to 50 parts per million required a really unique polishing process using a molecular absorbent.

There’s a variety of non-methane organic compound species and amounts and, really, the benefit of the multi-stage design that Linde put together was really making sure if you don’t catch it in one process, you can catch it in the second process, you can catch it in the third process.

So, we really feel comfortable that this really can provide a high performance, high level, high purity level of purified -- well, renewable natural gas that we then, in turn, liquefy. And this is the first case where the Gas Technology Institute has used their unique design to efficiently liquefy natural gas on a very small scale.

Normal liquefaction process, liquification process are going on a very large scale, of large facilities. A 13,000-gallon-per-day facility may seem large, it certainly seemed large to me, but it was really small in the overall scheme of things.

High Mountain Fuels Partners is a 50 percent joint partnership with Linde and Waste Management.

Waste Management is responsible for the biomethane production, Linde is responsible for the LNG production and on-site storage, and the logistics and distribution to our nine different fueling facilities in California. We're the ones that do the fueling at the various locations and consume the LNG, renewable LNG in our truck feet.

It's really major milestones, over 2.7 million gallons are produced, a proven maximum and sustained capacity of over 14,000 gallons per day, consistent up time of greater than 80 percent.

A number of rewards, and we're really looking forward to building this second plant, with the help of the Energy Commission, at our Simi Valley Landfill, in Southern California, to even provide greater fueling capabilities to our fleet.

One of the issues that's challenged us is the energy prices at the pump. This chart is from the DOE, the Energy Information Agency, and the annual Energy Outlook Report. This is the 2010 report, based on 2009 data. It's a little bit outdated and, actually, it's pretty easy to see why. I show this up there more for just a relative indication of where we are.

The upper lines, green and red, are their estimated projection of gasoline and diesel prices in terms of dollars per million Btu. Just as a point of reference, the $35 per million Btu is roughly equivalent to $4 per gallon gasoline prices, which is, of course, what we're seeing today in California. So, this chart is a little bit outdated, we're already up to approximately, in California at least, the 35 per MM Btu level.

The lower blue line, on the other hand, is the natural gas price, it's actually -- since this chart was put together, it actually has gone down a little bit, the natural gas prices are even lower than this. This is the price at the pump, not the raw value of the natural gas, alone.

And this is one of the reasons, one of the many reasons why Waste Management is in the process of converting its fleet to natural gas because of the huge price savings on the price of the fuel by transitioning from petroleum to a natural gas. That's the good news.

The bad news is in order to produce a renewable natural gas, we're probably at approximately the black line, and I just threw this black line on here as a relative point of comparison.

While it's still cheaper to produce renewable natural gas than gasoline or diesel, it's more expensive than getting gas out of the pipeline and either using it as CNG or LNG. There's a price difference. How in the world do we make up that price difference to make it worthwhile to invest in a renewable natural gas development project in California?

Well, RFS2 and the LCFS are important in this regard, we think. The problem is we don't have any experience and we don't know how to project long term the value of the LCSF and the RFS2 in terms of revenues, we just don't -- we have know way of knowing what those are going to be.

This is just a hypothetical example. If we produce, at Altamont, 13,000 gallons of renewable LNG per day, about a little bit less than 5 million gallons a year, it's about 400,000 million Btu per year, that's about 33,000 metric tons of CO2 GHG reduction.

Well, what's the value of the RINs under the RFS2?

Our consultants tell us that we think -- that they think our LNG, our renewable LNG we're producing is about 60 cents per gallon right now, but whether that's going to be true in one, two, three years, as you've heard throughout the day, the RFS2 and the value of your -- the value of the RINs could very well go up and down, or sideways, we really don't know where it's going to go. And at 60 cents per gallon, though, that's $7 per million Btu. What’s the value of the low-carbon fuel standard? Well, again, that’s likewise speculative. A lot of folks were talking about maybe 10 to 15 dollars per metric tone of CO2E. That translates then, at 15, to 1.25 per million Btu.

But lately, with all of the uncertainty over the LCSF, and there really hasn’t been any trades, and how do you do a trade, and this sort of thing, that’s just a significant uncertainty there.

But if it is valued at $7 per million Btu under RFS2, or $1.25 under LCFS, that’s about $8, a little over $8 per million Btu. If the basic fuel value of natural gas is $4, the potential credit value is twice the value of the fuel, if it’s $8.

If you take a look at the pump value of maybe $8 to $10 from a million Btu at the pump, for the natural gas, so at least a doubling, potentially, of the value.

So, there is a significant benefit to this. The problem is how do I got to the bank with that? How do I build a $15.5 million plant betting that I’m going to be able to get this $1.25, or $8 per million Btu to supplement the -- otherwise, just the raw value of the fuel?

So, this is the major concern that we have is just this uncertainty of what the RFS2 and the LCSF really means in real dollars, on a sustained ongoing basis, enough to recover the capital cost of building a $15 or $20 million plant.

Waste Management isn’t only looking at renewable natural gas. We’re looking at the 50 million plus tons per year of organic waste that we manage.

We kind of put this pyramid together of what we think the overall potential value of these materials, and other than putting it into a landfill, the next most valuable thing is pulling it out and using it as compost, and processing it that way.

But even better than that, we think generating electricity and producing power, producing transportation fuels is still a step up. Maybe making ethanol, and we’ve invested in a number of companies that are able to do these things.

And, potentially, gasoline, transportation, ultimately consumer chemicals or industrial chemicals produced from these organic waste in the landfills.

So, Waste Management is investing in a number of partners, that I’ve listed here. Terrabon, for example, is a company that makes organic salts that can be blended into the refining process to lower the carbon intensity of refined gasoline.

Enerkem is a gasification technology. S4 Energy is a gasification technology. Genomatica is a San Diego firm that is looking at taking materials, chemicals in the waste stream and converting the waste into useful consumer and industrial chemical products.

So, we're all excited about where the future is, but we -- it's a question of getting there and trying to make money in the interim process.

In summary, with respect to biogas resources, they are readily available in landfills and waste materials, publicly owned treatment works. Waste derived fuels have, really, the lowest carbon intensity. We can't imagine how any other source of fuel is going to have a lower carbon intensity than a waste-based fuel.

Renewable LNG and CNG is cheaper than diesel, and that's one of the reasons we're heading that direction, but it's -- but it's more expensive than fossil LNG and we need to rely on programs, like RFS2, and the Low-Carbon Fuel Standard, and the AB118 program to bridge the gap so that we can build these facilities, and get this product out there.

And that's exactly what government can do to help is continue to provide incentive programs. But more importantly than just throwing up incentive programs up there, we really want to have there be maintained predictability. And so we can hopefully -- well, we don’t feel we can count on 60 cents a gallon LNG under the RFS2, or even a 1.25 per million Btu for low-carbon fuel standard.

To the extent that that kind of predictability can be brought into the process, so we can rely on these as a source of revenue to support these investments, that is really the most important thing that can happen on a go-forward basis, from our viewpoint.

So, appreciate it. Maybe someday we’ll see more and more vehicles like this, where they’re closing the loop and running on rubbish to provide a transportation fuel. Thank you.

VICE CHAIR BOYD: Thank you, Chuck, great job. I have no questions.

MR. SCHREMP: Any questions from the people in the audience?

There’ll be a short, three-minute break while we resolve a technical difficulty.

(Recess at 4:01 p.m.)

(Reconvene at 4:05 p.m.)

MR. SCHREMP: This is the last of my three presentations and it will be covering our crude oil import forecast, our preliminary one, and some background on the high-carbon intensity crude oil screening process, or HCICO, to abbreviate that initialization.

So, crude oil, a funny thing happened since last time. You might notice that this didn't keep going down, it actually went up a little bit. Yes, in fact that's what has happened and that's primarily because of the increased activity in the bakken formation, mainly the Dakotas, a little bit of Colorado.

There's been some significant drilling activity, using an existing, an older technology that you hear common for natural gas, fracking is also being applied in the extraction of crude oil, as well as continued development of the Gulf Coast federal continental shelf.

So, there's been a rebound in domestic crude oil production in the United States, whereas we've seen a continued decline in Alaska, and California, and the rest of the U.S. in the last couple of years.

This is a close up of California's three components, the federal offshore, our shelves has been declining in state waters and on onshore. The biggest decline has been -- or recent has been the onshore portion.

There was a little bit of a rebound in the federal OCS in California waters, so in 2009 to 2010.

The much longer view, been producing oil for a long time in California, but taking into context that nearly 29 billion cumulative barrels of production, still only about 10 and a half months of global demand, 2011 global demand at a very high level, over 89 million barrels a day.

So, we've seen some ups and downs related to either rebound in the economy, wharf footing, depression, introduction of enhanced oil recovery, but ultimately a peak and then a downward trajectory that you see in most crude oil fields in the world. Not particularly in California.

So, here are some of the numbers. I don't have to go through all of them, but just point you to the middle bullets that there's been some significant decline in California and Alaska, and the rest of the U.S. is 40 percent. It would have been more except for that rebound that you saw.

So the rate of decline has eased somewhat in California, but with two more years of data, but not that much. And I'll talk about that in just a minute.

So, here are our sources of water-borne crude oil. We look at water-borne crude oil because this is an import infrastructure issue. And as you can see, over the last several years the total water-borne imports have fallen, so there is some implied spare capacity that has developed in the crude oil import capacity for infrastructure. And this is primarily due to economic downturn, the five-year decline in gasoline demand in California that we've experienced.

So, but when Alaska goes down, it's displaced by increased foreign, and when California goes down it will be displaced by water-borne imports, unless the total demand for crude oil declines in California because of product demand and lower utilization rates at refineries.

So, just historically, Alaska, I mean total imports have increased, but as you saw the Alaska portion is down, it's really on the foreign side. So, those foreign barrels increasing at an annual rate of 5.5 percent per year, so rather significant, and up 71 percent.

So, when we do a forecast, what do we expect in the future? Well, we look at -- we look at how the refineries operate in California, how we anticipate them, or what our assumptions are moving forward for their operations.

We also look at California's existing crude oil production and its rate of decline, steady, is it accelerating, is it decelerating, and so we do a bounded forecast on that.

So, we take these two elements together and it will yield incremental barrels of crude oil that wants to come into this market over the water because, once again, no pipeline is bringing crude oil to California.

So what has happened? One of these elements is the refineries and their utilization rates. So, what is that? Well, I have a certain process -- a capability to process crude oil at my existing facility and I run a certain amount of crude oil through there, and divide one by the other and you get a utilization rate.

Simply put, this is one element moving forward in our assumptions, does the utilization rate remain steady throughout the forecast period? We are assuming it will and we are going to be looking at two different rates.

However, the refining capacity is another matter. In this go-round for the IEPR we’re doing something that we haven’t done before, we’re looking at changing the trajectory of refining capacity in California to look at a scenario where it actually declines.

Now, why would we do this? As I mentioned before, 2009 forecast for gassing demand shows a decline, primarily due to CAFÉ standards improving and increased use of renewable fuels, both under RFS2 and the LCFS.

So, that will create a growing imbalance in the refining sector. What do I mean by that? They'll have more gasoline than they need when they process crude oil and they'll be lacking in diesel that can be imported, and jet fuel, for that matter. But this is a kind of growing imbalance for primarily gasoline producing machines that you might start to go down the path as the European structure, where you have to have a large imbalance, more gasoline, and less diesel.

So what happens is the economics of operating a refinery in California can start to change on the gassing side of the equation, and the diesel side, and ultimately you could see some pressure for a consolidation of assets in California.

Not unheard of, people look at the high refining margins in California and say, well, they're the highest in the United States just about, they must be the most lucrative. Well, no, those are just margins, the difference between crude oil and product prices.

What you do not see is what are their operating costs? Those are, like the margins, some of the highest in the United States. So, their actual profitability is not reflective in those margins, those just apparent margins.

So, where you see announcements of companies looking at maybe consolidating some operations in California, those are not maybe just idle threats, those are looking at their entire global and even U.S. portfolios and saying here are some of the low profit or even some loss leaders in refining assets.

So, we think that some refinery consolidation is certainly feasible, therefore, we want to include a projection of a decline under one of the scenarios because that will impact our crude oil import forecast.

However, it will have the opposite effect for the infrastructure to import petroleum hydrocarbons because if you don’t process crude and make the products here, you have to import the difference.

So, the decline rate, the other piece of the pie to perform the forecast is what is the decline rate doing? And this is remarkably similar to 2009. The actual, the low decline rate is 2.2 percent, that’s the most recent year.

And you may say, well, why do you use that, I mean what was it over the last two years? Well, actually, 3.3 percent.

So, this is sort of looking at over the last ten years, this is probably one of the lowest rates. Not a surprise. Very high prices of crude oil in California and increased drilling activity, so there has been -- this is rather shallow.

A steeper rate is the ten-year average. But even, as I said, if I took a two-year average it was 3.3, so we're still within the bounds.

And that is very similar to two years ago when it was 3.2 on the steeper decline rate.

So, this sets the table of how much incremental crude oil one would need assuming refineries kept operating at the same level of capacity and the same level of utilization.

So, here are our assumptions and feel free to weigh in, comments here today, after the fact, before the 23rd, as was stated for the comment period.

So, we're just looking at bounding this. What are some, maybe, of the sort of larger import forecasts, and that's taking the steeper decline rate in the bottom, and that's taking a flat refining capacity, no refinery creep, no expansion in California, and a higher utilization rate over the last ten years of 90 percent.

And, yes, some will say, well, isn't there a refinery in Big West that could become -- come back and in service? They've talked about that, very true. However, they're not going to use any crude oil. The game plan is to take unfinished oils and process it at the facility to produce gasoline diesel components, rather than crude oil. So, that's not an incremental crude oil demand in the system for our assumptions here.

So, what this does is actually dramatically change the need for incremental crude oil into California from what we had two years ago as 235 million incremental barrels per year, by the end of the forecast period, now down to 104.

Still significant, still nearly a third increase from the 2010 levels, so still an infrastructure issue. And this is especially for, say, Southern California, which is about, I think, 60 percent of the imports.

The low forecast, changing our assumptions, has a different outlook. We're using the less steep decline rate, 2.2. We're using a more near term lower utilization rate, 88, and we're introducing this refining capacity decline.

Now, would it gradually go down over time? No. If there was a refinery consolidation, it would occur all at once, so you see a step change down. But this is just to illustrate over the forecast period a decline of total capacity and what it can mean for imports in any particular year.

So doing this, compared to last time, we had 147 million more barrels over the forecast period, and now it's only 22, so that's a remarkably different outcome using this new assumption about refining capacity.

So, our focus is primarily in Southern California. No disrespect to Northern California, there are some issues there and we will be exploring them in our report.

But there is a new infrastructure that's been discussed in the Port of Long Beach, that's Pier Echo. Don't know where this stands and if it has legs, and we'll continue to move forward. Certainly, the Ports of L.A., Long Beach do not need to brand-new import terminals to handle incremental crude oil, only one.

Pier 400 -- berth 408 and Pier 400 has been at it a long time, that's Dave Wright. They've been working tirelessly and this has been going on for multiple IEPR cycles, so still nothing, yet. But we don't know at the end of the day what's ultimately going to be happening here, but this will require a significant amount of investment, partnering with clients to sign up to long term.

So, there is some uncertainty about moving forward, especially when we present these scenarios in the crude oil import arena.

Any questions on that before I go on? Yes, John?

MR. BRAUTIGAN: Jon Brautigan, with Valero. When you looked at your declining capacity utilization case, which is based on I’m assuming, like you said your future CAFÉ projections and other things, did you put a component in there for AB32, where all of the sudden the California refineries are penalized because they have stationary source emissions that they have to offset, and the foreign imports of the CARBOB wouldn’t have that penalty?

MR. SCHREMP: We did not assume that AB32 would be a driver for some refinery consolidation. We understand that AB32 will likely incur some cost, either on the investment side for refining infrastructure and/or the purchase of carbon KRESS that will have some positive costs that we think will be passed along to consumers in the long run.

Does -- is that a regulation that is not existent in other parts of the United States or other parts of the world? Yes, that’s true, so there can be introduction of sort of a new cost element in refining operations in California. But we also recognize that in other parts of the world there are some other regulations that refineries in, say, Europe are under, that do have incremental costs that, say, aren’t currently existent in California, so there are differences.

But I think the United States, John, sort of the near term or close-by competition, there is not an AB32 component in the United States at this time.

Well, if there are no other crude oil questions, I’ll continue.

High carbon intensity crude oil, or HCICO, is an element of the California low-carbon fuel standard. And, essentially, what we’ve been participating, some technical workgroup associated with this element of the regulation, and providing some analysis. And this regulation does look at crude oils in terms of their carbon intensity, and that has to do with how they’re produced and brought to market. And it’s really in the production side, not necessarily the transportation side, because all the crude oils have to be, for example, transported in marine vessels at some time to California.

So, we’ve done a lot of work in this area. There are four categories that can trigger a fail and be put into a basket of potential high carbon crude, as the Air Resources Board has structured this element of the regulation.

We’ve done some work on this, you’re welcome to go look at the details of it, here’s the link. But essentially we looked at marketable crude oil names, so MCONS, and I apologize for the acronyms, 251 of them, so quite a few different crude oils available on Planet Earth, and quite a few countries, over 47 of them.

This table is only meant to illustrate the diversity of crude oil country sources. These are marketable crude oil names, they are country sources, and the number of different crudes from each of the countries.

You'll notice the highlights of red, those are countries under the ARB's regulation that were grandfathered, 206 baseline countries and then, you know, exempt from this element of the regulation.

So, you can see there were a certain amount of crude oils coming from those countries and then that's changed. In fact, in 2010, although it does say one on this slide, that's a bit old, I think there were no crude oil imports from Mexico in 2010 whatsoever in California.

So, the screen was performed, the vast majority of the near 75 percent of the crude oils received a pass. And it's interesting to note, even if you were to screen the grandfathered crude oils from outside of California, they would pass, there wouldn't be any fails.

However, grandfathered crude oil, say, from inside of California does have a significant portion of thermally enhanced oil recovery crude oil, and so that certainly would fall under the potential high carbon category, if you were to screen those.

So, we looked at the fails and eight of the 45 were imported during 2009. And then -- and here is just sort of list of which ones failed or the number, depending on the category. Flaring, depending on enhanced oil recovery; mining, which occurs in Canada, the second to the last bullet.

And then you have things called upgraders, taking a crude oil and actually sort of partially cooking it and getting up with a lighter crude oil that's already been partially processed. And that's something that can occur in Canada, and is also occurring in Venezuela.

So, just looking at the total number of counts, not adjusting for some crude oils are available in larger quantities, and other -- here's just a scorecard of why they were placed into the potential high carbon categories and it's about -- according to this it's about, you know, a little over 20 percent of total numbers.

This is looking at 2010 imports to say, well, did any of those come into California in the most recent period? And this is up, as I said, through November of 2010. And the answer is yes. And it’s about, I think about 16 percent of total foreign imports, but we use about half of that as foreign. So, it’s about, you know, 70 percent of total crude oil imports for all uses during this period of time.

Now, the process of the high carbon crude oils can -- the incremental carbon can be offset. Refineries would have to use greater amounts of renewable fuels in the correct carbon intensities. However, it becomes increasingly more difficult. Not only does the LCFS regulations become more and more difficult as time goes by, it starts off easy, gets progressively more difficult, so offsetting becomes even harder.

So, to put some of this in context, if they were to use the same quantity, the refiners, in 2011, of these high carbon -- potential high carbon crudes, the offset would be, basically, you’d have to use nearly all California and Brazilian ethanol in all of the gasoline today.

So, that’s unlikely. From talking to the refiners they are looking, and have looked, and have been purchasing alternative crudes, instead of these potential high carbons because understanding that the offset is challenging, and especially for those who would like to build up credits to use in latter years under the LCFS program, itself. Oh, by which that the credits don’t have an expiration date, as they do under the federal RFS2, which we think is a good idea.

So, looking at a more reasonable high carbon crude oil mix of, say, two percent, it still becomes increasingly challenging, especially you can reach some feasible solutions by 2013, meaning that kind of low carbon ethanol doesn’t yet exist. And it would be cellulosic, but it just doesn’t exist right now.

So, we think, as part of our assumptions moving forward, that potentially potential high carbon crude oils are not going to be available to refiners effectively speaking for purposes of this.

And so when you do a volume weighted adjustment the percentage does change a little bit, so it becomes more like 26 percent of the foreign crude oils in this snapshot for 2010 are in the potential high carbon category.

And you also want to recognize that why I keep saying potential, it is just that. Companies can provide additional information to the Air Resources Board, staff identifying why a particular crude oil may not be high carbon.

I'll give you an example. Under the flaring criteria, basically all of Russia crude oil production, you know, in excess of 9 million barrels a day, is higher than the level set by ARB, so it would be a potential high carbon.

Well, there is some crude oil that is, say, primary production, that is from a group of fields that can possibly have lower than the level set by ARB and would, therefore, fall out of the potential high carbon and then be able to be used, but you need to demonstrate that with, you know, a sufficient amount of detailed information on its production.

So, there is the possibility to do that under this process, so ARB does have that.

So, I just wanted to reiterate that companies have been changing their purchasing decisions. From what we understand and the information we've been collecting confidentially, that's usually resulting in a higher acquisition cost for crude oil that we do think will be passed through to consumers in the long run.

And also, I think as Malachi mentioned this morning, energy security is something that we're going to be looking at under some aspects of our analysis in various issues and, certainly, this is an issue that does have a potential energy security implication.

Meaning that, say, Canadian crude oils, which is probably a very high energy security source, relative to others, would be precluded, and so that has an energy security implication, as just an example.

Those complete my comments, any questions?

MS. GREY: I don't see a bird.

MR. SCHREMP: It's right back here. Gina's referring to some monthly Western States presentations I do that almost always have a bird picture at the end. Different audience, I just didn't -- you know, I didn't want to shock you.

Any questions from the guys?

VICE CHAIR BOYD: No questions. I'm still trying to figure out the vast wasteland conclusion here, but anyway let's let Gina comment on it.

MR. SCHREMP: Well, unless we have any questions right now on my slides, from the audience, and it looks like we do in Dwight Stevenson, Tesoro.

MR. STEVENSON: Thank you, Gordon. At the risk of making a statement, I'll ask a question and see what your answer is. If you're going to slice out some of the potential crude supply in the California, and California refiners are going to have to go further out to get that crude, what impact do you think that's going to have on the entire market as opposed to just that seven, eight percent? Do you think that the whole crude market's going to shift up in price or do you think only that seven or eight percent's going to shift up in price? How's that for a loaded question?

MR. SCHREMP: Well, we do -- I mean, crude oil is a global commodity, impacted and it seems like more recently significantly impacted by geopolitical events and cash flows in and out of futures markets, and other commodity futures market opportunities. So, those prices will elevate up and down.

There are differences, depending on quality, that do occur. And so, I mean, companies having to go -- I mean, let me just back up. I mean, from what we understand in talking to the refiners, they're looking at alternative crude oils, they don't necessarily look at an alternative crude oil that is less expensive overall, meaning they have to incorporate the acquisition price and its impact on the operations of the facility.

MR. STEVENSON: Uh-hum.

MR. SCHREMP: So, refiners are using, likely, the optimal sources of crude oil for their price points, operational economics. So, going out and changing that dynamic we understand is seeking out a -- is turning out to be a higher cost crude oil, we think that's going to increase the acquisition cost for crude oils in California from that mix.

So I think, yes, they'll -- I mean that's a way of looking and saying the whole entire complex is going to be a bit more expensive. You're talking from the California perspective rather than, say, affecting global crude oil prices?

MR. STEVENSON: No, I meant the California, yeah.

MR. SCHREMP: Yeah, we think that costs of crude oil -- the crude oil acquisition price for California refiners will net increase, yes.

MR. STEVENSON: Thank you.

MR. SCHREMP: Seeing no other questions from the audience, we'll go ahead and we have Gina Grey will be our next speaker.

MS. GREY: All right, thank you. Good afternoon, Commissioner Boyd and to the entire audience here that's still left in the room. And I assume there's some on by WebEx today.

My name is Gina Grey and I am here representing the Western States Petroleum Association and my position there is Vice President of Strategic Policy and Fuels, and that's for our entire WSPA organization. And then I also oversee three states, which is Arizona, Nevada and

Hawaii.

And I think I'd like to just start with a couple of general comments, based on what I've been listening to today. And, you know, one of them goes to sort of this sense that I got from some people that, especially with John Brautigan's presentation, after that, that the oil industry is the purveyor of doom and gloom scenarios.

And I know that might be felt by some when we do get up here and we tend to talk about all of the challenges, and the barriers, and the costs and everything that are standing in the way of alternative and renewable fuel expansion into the State.

But I personally prefer to think of us as more purveyors of reality because, as people said, the people that are in this room today were invited because they have experience in transportation fuels. And, certainly, the petroleum industry has a lot of experience in transportation fuels, that I can say.

And so in some ways I think what you are hearing today is perhaps a dose of reality on some of these aspects. It may not be shared by everyone, people have different perspectives on how things are moving.

But if you do take an historical look back at how long certain things take to come into the marketplace and, you know, I've been with WSPA for 22 years, and I can certainly say that I've sat through my fair share of alternative and renewable fuel workshops and conferences, and have heard these discussions quite a bit. Not to say that things haven't progressed over those 22 years.

But I think the time frame within a lot of these things takes place often is much longer than anyone would anticipate or even want, and there are a lot of issues that tend to crop up, and you heard some today. Some are in the investment arena, some are in the permitting arena, you know, some are in standards, and codes, et cetera, and all these things tend to crop up.

And often these transitions into new sort of ways of thinking of things and new transportation fuel scenarios don't take place within the time frame that people want, so that's just one introductory comment.

And so I would just say this who WSPA is. We have 26 petroleum companies in six western states. And what you will see is this is our sort of first, opening slide and at the end you will see our closing slide, which actually indicates that even though we are sort of big oil, people traditionally think that we are only in petroleum, our companies actually are very heavily involved, investment-wise with their own dollars, in terms of moving into the alternative and renewable fuels arena.

Okay. I took a little bit of liberty here with the Bowen Bill and tried to indicate that, obviously, the State goal, as was stated by Malachi at the beginning, was to reduce emissions and carbon from the transportation sector, and that the whole IEPR exercise is to do that, while ensuring adequate, reliable, and here was the WSPA twist, affordable supplies of transportation fuels.

And I think the Bowen Bill said “reliable, secure and diverse,” so we’ve added in “affordable” in there, as well, as being one of the main goals.

I think it’s quite a charge for the Energy Commission to have to -- this year, in particular, I would say, take on the role of trying to look at not only what’s been occurring within the transportation fuel arena, but then to project out what’s going to occur, I think that’s the real challenge for this year’s 2011 IEPR. It’s quite a tall order.

And, you know, everyone else talks about the three-legged stool, the vehicles, the fuels, and the consumers, but more than anything I think we would emphasize that it’s critically important in this coming IEPR to make sure that all three of these are very thoroughly vetted. Because typically, you know, I've heard a lot today about fuels, we heard a little bit about the vehicles, and we heard a little bit about the consumers. All three of those elements have to be working in sync, entirely, in order to have any movement forward on this, because if one of those doesn't work well, the rest fall apart.

And I think you heard Tim Carmichael, for example, talk about even though there are vast quantities of natural gas available the vehicles, the light-duty vehicles, for example, are not necessarily available in the market place. And, you know, he's not overly thrilled with that prospect.

And again, if you don't consider the consumer, that's the other critical piece of this.

So, I would say here that -- just let me move on. I've tried to portray here, really, the fact that this particular IEPR, you know, the focus is going to have to take into consideration some things that have not been there in the past.

And two of them, definitely, I think in the last IEPR RFS2 was discussed, and there was some consideration of that. But, certainly, the California LCFS program, Low Carbon Fuel Standard program is something that will be heavily focused on, hopefully, this time around in the IEPR>

In 2009, when you did your last one and dealt with transportation fuels, that was the adoption year. This year is the year of implementation, the first year of implementation. And even so, as was pointed out earlier, there's a lot of gaps in the LCFS program even now, so we're kind of off to what I would coin as a soft start with the program. And as such, as the program continues to roll on, I think people are going to be needing to ask a lot more questions, a lot more details. Not just going with the optimistic everything's going to be fine and it will all work out type of scenario.

And, you know, we've dealt historically with fuel specifications, which is the fourth bullet here under mandates, but this is truly a transforming LCFS regulation, where it's attempting to revise the entire transportation fuels arena in the State. And because of that it's not just simply, well, we've tinkered with some specifications and the vehicles are there to receive these new fuel specs, it's totally transforming.

AB118, under incentives, that's been talked about a lot today and I think you've heard from a lot of the fuel folks that were represented the desire to have additional incentives from the AB118 or the California program, as well as all the other incentive, both the federal monies and other monies that are flowing into those fuels to sort of kick start the entire scene.

And then I've listed out some considerations and challenges, that I'm not going to go through these, I just sort of wanted to point out what some of those are, and we've certainly heard a lot of those today.

And we're here today, basically, to talk about infrastructure and the distribution system.

Gordon did a good job of talking about what's going on in the port area, and I'm not going to belabor this, and I don't think there are a lot of answers to a lot of the questions that he posed so far. Other than I think, in addition to what he shared with us this afternoon, we also need to think a little bit about, you know, other than the, okay, here's what's happening to crude oil in the State, and here's what theoretically should be happening, therefore, in the ports and the terminals, I think we also need to be asking some additional questions.

You know, along the lines of, well, what if port infrastructure expansion is needed to handle crude oil and product imports, or petroleum product exports? And no one's really talked about the product exports, necessarily.

Depending on how our companies, and I'm not forecasting anything here, I'm just saying there are definitely some possible scenarios for how the regulated parties might react to some of the things like the Low Carbon Fuel Standard, and there might be a possibility that they would say we are going to export our product offshore. So, again, that would mean some need to look at what the infrastructure is going to be needed at the port to handle those exports.

And definitely we talked about additional imports of crude oil from elsewhere in the world.

And then, also, port infrastructure expansion needed for alternative fuels and blend stocks to comply with both RS2 and the LCFS.

And then, thirdly, just the key here, which Gordon touched on, which is how long it takes to resolve issues at the port. And I think he mentioned Pier 400, which I've been told has -- I think it's ten years, now, that that's been worked, so it's taking a very long time. And traditionally these things seem to take a very long time in the ports.

And, of course, there's not only timing implications, there's also cost implications and energy security implications, too. And the question always comes up, well, who's going to bear all those costs? That's always the kicker.

All right. And, really, one of the key things that WSPA wants to get across today, and it flows from what Gordon was talking about in terms of the Low Carbon Fuel Standard, is the treatment that ARB has decided to adopt in the Low Carbon Fuel Standard for the treatment of crude oil, and how that all is going to be treated.

And Gordon's portrayal this afternoon showed the draft process that ARB staff has been working up to this point in time, and it shows sort of the differentiation approach that CARB is trying to achieve by saying worldwide there are some crude oils that are much more carbon intensive than others, and somehow we have to factor this into the process.

Scientifically, perhaps, and this is not a comment by WSPA, but scientifically folks could sit there and say maybe that makes sense. But there is more than science that needs to be considered in a lot of these decisions, as we move forward, to make sure if in fact the Low Carbon Fuel Standard is going to work and achieve what the goals are, some of these aspects that are being put into play are not conducive to that goal.

And I just wanted to put these two last bullets here in red because we're always being asked, well, when can the Commission enter into the debate, what does -- who -- in terms of the stakeholders, when do you think that you should engage?

And I would just like to point out that we think there are a couple of points in time here this year, with the ARB, when first of all they're will be some revisions, potentially made to the regulation. We're not too sure exactly when that particular hearing will be held, maybe in December of this year. It may be even, say, January or February next year, but definitely within the year there will be a hearing to address changes to that LCFS program.

We would invite you to weigh in at that hearing.

And periodic reviews that were required in the resolution that came out of the April 2009 Board Resolution. 2011, this year, as Gordon alluded to, there is an advisory panel of sort many stakeholders that are sitting around the table, trying to look at what the progress has been on this Low Carbon Fuel Standard, trying to determine are there changes that may be needed, et cetera.

And Gordon does sit on that advisory panel, and we would just, again, welcome the Energy Commission's input to that, as well as all the statistics, information, data that you folks carry and obtain from our industry, and others, under Pyra confidentiality, that would be very helpful as input to that process.

And I've just outlined for you here, in case you were unfamiliar with the advisory panel, here are all the topics that this advisory panel are supposed to look at this year, so you can see it's a very long list. And down towards the bottom, topic 14 is the high carbon intensity crude oil, which is one of the most important issues for our industry.

And again, just a plug, asking CEC to please provide input and guidance into that Periodic Review Panel, would be very helpful.

And I'll try not to go over the ground that Gordon's already talked about, I think he did an excellent job of trying to depict what the whole high carbon intensity crude oil issue is about.

But essentially, as I said earlier, it's an attempt to differentiate crude. And WSPA has said, from the beginning, that we disagree with any type of attempt to differentiate crude, particularly when you're trying to kick off a program of the magnitude and complexity that the Low Carbon Fuel Standard already is, on top of an RFS2 program, on top of everything else that our industry is being required to do, it just is not conducive to making sure a program like this is going to survive.

And the two points at the bottom here are really the most critical ones that Gordon did mention, is what it does is it really creates a deficit if you use a high carbon intensity crude oil, and then you have to make that up somehow. And you have to make that up either through some kind of low carbon intensity blend stock, like an ethanol, cellulosic, otherwise.

And the question always comes up is are there going to be sufficient volumes of those types of blend stocks in order to offset the deficit?

And the last bullet here is just, you know, the implication to this is that there are going to be crude oils around the world, and whether they’re the Canadian oil sands, or whether they’re from Russia, or whether they’re from some of these other areas that right now, through the crude oil screening process, appears to say that some of these crude oils around the world will be deemed to be high carbon intensity crude oil and, therefore, be penalized.

As Gordon says, your options as a refiner are pretty limited and it can create all sorts of unintended consequences in the market place if you select one of those options.

So, it’s -- again, it’s just very important to us to make sure, again going back to the Bowen Bill, and making sure that the transportation fuels and the energy in the State are reliable, and adequate, and affordable, et cetera.

This particular provision, in the LCFS, works directly in opposition to that theory.

And I think Gordon showed this earlier and, you know, I think it's the half -- it's the glass that's half full or half empty. And some people look at this and say, oh, well, oil industry, what's your problem? You know, you have three-quarters of this pie to go and select from. And, of course, we're looking at the other piece of the pie and saying, you know, those are the pieces of the pie that traditionally we, as the refiners, may have been purchasing those crude oils. those crude oils are suited for our refineries and we just can't go out, necessarily, and purchase the rest of the pie. Plus, it raises us a whole slew of other issues, which are listed, some of them, on the next page here. And this is my second to the last slide.

And excuse me, my voice, I'm just getting over the flu.

Really, this crude differentiation approach, there are many, many implications that can arise out of this, and the one term that everyone probably has heard about is crude shuffling. And that's where basically, and just as an example, you're saying to the Canadian oil sands, you know, you’re no longer desirable, your crude oil, because it’s deemed to be high carbon intensive. So, Canada says fine, we’re going to send our crude oil over to Asia.

Well, the vessel that takes that crude oil over to the Far East, for example, goes a lot further to go to the Far East than it would have to, to come down into the port in California.

So, indirectly, you’re creating excess greenhouse gas emissions by forcing this crude oil to go somewhere that’s a further distance. So, that’s what crude oil shuffling is.

There’s obviously the energy security issue and many people have said that, you know, why would we turn away a neighboring country’s crude oil? They tend to be a friendly country. So, again, when people raise energy security as an issue with petroleum, why would you try and discourage Canadian crude oil to come down.

And then mentioned earlier was the refinery configurations and, you know, those refineries have spent billions of dollars to configure themselves in a certain way to process certain types of crudes. It’s not a very simple process to just change your crude slide overnight, if ever.

And then, you know, that could lead to other consequences, as Gordon mentioned, in terms of consolidation, et cetera.

And then changes in amounts of crude oil processed, that's always a consideration, obviously. It would just be to drop your amount of crude oil that you're actually processing, and then that results in less product, less fuel.

Or as I mentioned earlier, another option might be to just export the product, so California doesn't see a drop.

And then infrastructure requirements for fuel, blend stocks needed to compensate for the HCICO deficit and, you know, that was, I think, briefly touched on by Gordon as well.

And I just listed out here some of the assumptions that we, as an industry, sort of have felt are being made by ARB, in the LCFS program. And these are all issues here that I think need to be asked by the Commission and to see if, in fact, these are valid or not valid.

I can't comment, especially being in a trade association, I don't have intimate knowledge of what each of our companies is about to do, or not do.

But, certainly, these are some of the real hard core, on-the-ground questions that typically have never gotten asked because there’s always an assumption that our industry will be in the State forever, and we’ll be providing all the transportation fuel that’s required on the petroleum side forever.

Okay. And here’s the last slide, and this is the companion to the first one, where I said that we’re all considered to be just petroleum companies and definitely not. We actually spend a significant amount, if not more than the majority, including the federal government, on the development of alternative and renewable fuels.

And I think my closing comments are just, you know, someone used the term earlier that this is -- the LCFS, in particular, is a grand experiment, and I would support that. I think out of all the programs that we’ve seen, it tends to be the one that’s most like an experiment, particularly when it has the regulated party as the petroleum industry, basically. And we’re being told that we need to go out there and either we produce the low carbon intensity fuels, or we blend someone else’s product in order to achieve that low carbon intensity level, or we purchase credits off of someone who is producing that low carbon intensity fuel, as in electricity or potentially hydrogen, et cetera.

And I think the thing that people often lose sight off, when we get into these alternative fuel discussions, are the volumes. And I think Malachi mentioned at the beginning, you know, 20 billion, with a “b”, gallons of transportation fuel every year in this State.

And when you start hearing bout some of the amounts of alternative transportation fuels that are being produced, they’re not in that realm.

And that’s not to say that at some point in the future they won’t be in that realm. But again, as I said earlier, timing is one of the critical factors here that, you know, is the industry, is the entire transportation fuels arena being provided enough time to transition?

And I know it seems like an eternity that we’ve been talking about these issues, and everyone says, well, why haven’t things transitioned over, yet? Very good question and there are lot of reasons for that, and lot of them relate to things like cost, capital, all the issues about the incentives that people were talking about.

So, you know, the risks, the investments necessary.

And then just to close I would say one of the worse things that can happen is, and this traditionally is what goes on in government, is there are programs that are put out that are very aggressive, and the LCFS program is one of them, the zero emission vehicle program is another, and there's probably tons of other examples, with the hope that at least it will spur industry to move forward.

And then as we move down the road and things aren't happening the way that folks wanted within the time frame, then those programs get changed. And this is something we've seen constantly happening.

Not to say that's bad, things have to evolve, et cetera. But what is lost in that whole evolution and changing of programs is the fact that people do need certainty, I heard that quite a bit today, in terms of making investments.

And stranded investments are not going to help anyone, they're not going to move low carbon intensity fuels out into the marketplace.

And so we would just close by saying, you know, the role for the California Energy Commission right now, in this IEPR, is really critical this year to start looking at all these questions in a very realistic manner, asking some very hard questions about the costs, et cetera, and not assuming that the entire low carbon intensity alternative renewable portfolios of fuels is going to stand on an AB118 or an incentive-based, you know, footing. There needs to be more than that and often that comes down to things like timing, et cetera.

So, thank you. Anymore questions?

MR. OLSON: Thank you, Gina.

MS. GREY: Thank you.

MR. OLSON: Commissioner Boyd had to leave early for a flight, he apologizes for that. It doesn't show disinterest.

MS. GREY: That's okay.

MR. OLSON: And we'll have some -- he's going to have some follow up with the staff to go over what he missed here.

MS. GREY: Okay.

MR. OLSON: So, then I guess if there are any questions on Gina Grey's comments?

MS. GREY: Okay, thanks very much.

MR. OLSON: Thank you, Gina.

MR. SCHREMP: Thank you, Gina. We have two more speakers. John Brautigan will come up here and he has, I think, three more slides that were the tail end of his presentation this morning, that are associated with the high carbon intensity crude oil issue.

And then after John, we're going to go ahead and have Mike Waugh, who is from the California Air

Resources Board, who will also be speaking.

So, John.

MR. BRAUTIGAN: Okay, thank you. I’ll try to keep this short. Gina, I’ll accept the label of somebody that’s trying to do an honest assessment and staying with reality, versus doom and gloom. That’s all I’m trying to do.

We -- for instance, we’ve talked to the EPA on Tier 3 gasoline and we told them, yeah, we can do 10 ppm sulfur, we can do that, that’s technically achievable.

But I filed the RFS2 production outlook reports for Valero, we produce 1.1 billion gallons a year of ethanol, at ten ethanol plants, and I know what we’re looking at for future cellulosic or biodiesel production in our planning process. And I’ve ratcheted those back in the March report versus what was sent in, in August, things are just moving slower.

There will be electric vehicles out there, there will be cellulosic ethanol, there will be a lot of stuff, but just not enough, we believe, to meet the percent reduction standards in the LCFS, and not enough to meet the targets in the RFS2. So, we’re just trying to be honest.

Anyway, okay, the question we were asked to answer was “Has the HCICO issue altered our purchasing decisions?" Yes. Valero is trying to minimize its HCICO purchases this year and we do not plan on buying any for delivery after September 30th of this year, when it can no longer be treated as normal crude under the advisory that CARB issued.

We think HCICO disadvantages California refiners. We would urge Gordon and staff to maybe reconsider. We've got AB32 coming in, just for impacts of California refiner rates in the future, raising our cost, but not raising importer's.

We've got the renewable electricity standard that's going to raise our electric costs.

We've got the HCICO issue, going to raise our crude costs.

And we have potentially new competition from this pipeline coming from Utah into Nevada.

You know, the things are lining up not in favor of California refiners, so that you might see some more -- I don't know what's going to happen, it's just -- but there's the pressures and not in the direction to be upping capacity or necessarily to maintain all the capacity that's there, potentially. Okay.

The other thing is some California baseline crudes have a higher CI than non-baseline HCICO crude, so it’s just disadvantaging these crudes from being run at California refineries.

How easy is it to difficult -- or how easy -- somebody didn’t proof this slide very good. Or how difficult is it to offset the incremental carbon debit of HCICO during 2011 and would it be more difficult in 2015?

If you use the default number of 20, and you subtract that from 6.3, you get about a 13 CI debit that you would have to apply to the corresponding carb diesel that you produce.

Now, remember the baseline’s running at 98, so that’s like a 13 percent increase in CI. The whole LCFS program, by 2020, is looking to reduce the pool by ten, so it’s almost like trying to have, for that portion of your products that comes from high carbon intensity crude, it’s like trying to meet the 2020 goals in 2011.

Now, what’s out there? There’s 80 to 90 CI ethanol out there. Okay. Some of the plants, we do know -- I do know of one, we believe one producer did change an energy mix and is potentially using biomass instead of coal. A lot of plants just looked at their energy consumption and said, hey, CARB’s default values were too conservative, we can refile.

And Valero’s looked at this and is deciding what we want to do. We can refile and get a lower CI for the Midwest corn ethanol plants.

The problem is you can't necessarily get a hundred percent, 80 CI ethanol. A lot of the ethanol is marketed by marketing companies and what they're doing is agreeing to contracts that they will supply you with maybe 90 or less CI ethanol. That way it doesn't tie them down to a specific number and sourcing it from a specific ethanol plant, and maybe that plant having trouble and not being able to switch barrels.

So, just because there's plants at 80 out there doesn't mean you can run a hundred percent 80 CI ethanol.

And if you look at the volume metrics again, okay, you know, I got 9/10s of a gallon of CARBOB, 1/10th of a gallon of ethanol, and then I got an energy content of 70 percent of the CARBOB for the ethanol, it's just trying to offset the higher carbon intensity of the HCICO just gets very hard.

If you could get all 80 CI ethanol in 2011, you could maybe run, and this will vary from refinery to refinery, but 50 percent high carbon intensity crude in 2011, okay. And this would be if we weren't having the ability to treat it as normal, okay.

And in 2015, probably none, so it will have a big impact, okay.

So, it’s just -- I don’t know, to us it just doesn’t make much sense. You’re negatively impacting California refiners, you’re eliminating as much as 25 percent of the crudes that we were running. The crude’s still going to be run, it’s a global commodity. It’s not going to -- Nigeria isn’t going to care and stop flaring, they’re going to base their flare gas -- their gas recovery on economics and we’re not going to be able to get any good information out of the producers.

They don’t -- I’m sorry, but the California market is not big enough, a big producer doesn’t care if his crude is excluded from the California market.

Now, I know the Canadians would probably disagree with that. I’m talking about foreign producers that don’t even know about this when we go and talk to them.

Like when we go and talk to the Russians that produce ESPO, I mean they think we’re crazy, they have no idea what we’re talking about, okay.

So, that’s it for my comments. Thank you. Any questions?

MR. OLSON: No questions.

MR. SCHREMP: Well, if there are no questions from the audience, I’d like to have Mike Waugh, from the

California Air Resources Board, come to the microphone.

MR. WAUGH: Good afternoon. I’m Mike Waugh, I’m Chief of the Criteria Pollutants Branch at the Air Resources Board, and it is my branch that has been very busy. We’re working on fuel specs for CNG as a transportation fuel, E85, E10 certification fuel, biodiesel, and renewable diesel, and also we’re responsible for the Low Carbon Fuel Standard.

So, when I say that we’ve been busy, I guess that’s the take home message that we’ve been working hard and been working with our stakeholders.

I’d just make a few comments and some global comments, and a couple of detailed comments.

First of all, the Low Carbon Fuel Standard is a performance-based standard, and so all the alternate fuels are welcome, CNG, RNG, electricity, hydrogen, E85. So, today’s presentations, in terms of the status of that development, it was really good to hear today that LCFS, by being a performance-based standard, it provides flexibility and also drives innovation, and that is the intent of the LCFS. And I think you saw some of that today.

You know, we do understand the challenges ahead of meeting the LCFS and RFS2. I think Gordon said this morning that no additional ethanol needs to be brought to California to meet the LCFS, and that's consistent with our analysis, it just has to be a lower carbon intensity.

And the lower carbon intensity, really, you're really talking about cellulosic ethanol. And I think several speakers today have talked about the fact that we're not seeing the rollout of cellulosic ethanol and that is creating a challenge for the RFS2 and a challenge for the LCFS.

One thing of the LCFS is that it's back-loaded. The early years are pretty modest goals. For example, this year the CI has to be reduced by a quarter of one percent, and that goes to a half of one percent next year.

So, we designed it so that there would be some time for some of these technological developments to occur.

Another thing that we're seeing, the LCFS allows biofuel producers, and I think John mentioned this, too, to apply under what we call a method 2a or 2b. These people, these producers would say you're right, we're more efficient than what's in the look-up table, they're allowed to provide a technically compelling case, and there's been quite a few of them in fact. And a lot of the Midwest ethanol plants have received a lower carbon intensity than the default value, so they’re more efficient. And I think we’re starting to see that, too, that’s some innovation, as well.

We’re also working on some internal pathways, including an anaerobic digester. I think Chuck White mentioned a digester. And we’re working on that pathway, as well.

So, again, I think that we’re looking at all types of alternative fuels here.

Regarding credits, we won’t know how many credits have been generated until the end of this month, that’s when the first quarter of 2011 reports are due. At that point we’ll be able to see how many credits were generated, who generated the credits, and where people are relative to the standard.

We’re working on a credit tracking and trading program. Actually, I think we’re going to have a short-term proposal. Long term, I think the long term it’s going to have to be part of our LCFS reporting tool and we are working right now on an RFP to get a contractor to provide that module for our reporting tool.

In the short term we’re looking at something that’s a little bit more manually based, that ARB would be involved in, that if someone wanted to move credit from one place to another, that we would be involved in that in the short term.

In the long term, we think that the reporting tool would handle a lot of that automatically.

Regarding HCICOs, first of all, you know, we like to thank Gordon for doing the screening of the marketable crudes, he does very good work.

Also, I would like to thank Gordon for making the differentiation, earlier today, between a potential HCICO and a HCICO.

As you saw from the pie charts, three-quarters of the marketable crudes passed the first, simple basic screening. So, I wouldn't say that I look at it, look at the glass as being half full, I look at it as being maybe three-quarters full at this point. And I do think there's opportunity for other crudes to be designated as non-HCICO crudes.

You know, Gina did mention that, certainly, from a scientific stand point, Canadian tar sands, one would easily be convinced that the energy required to produce that crude oil is different than conventional crude oil. And since we look at a complete lifecycle analysis when it comes to the LCFS, we'd be remiss if we did not take into account the higher carbon footprint of Canadian tar sands.

One of the things that -- well, first of all, California is not the only entity that's concerned with Canadian tar sands. Europe is, I think there's a global concern for that. And one of the allowances in the LCFS is that if carbon capture and sequestration is used for some of these HCICOs to bring down their carbon intensity below a certain level, then they end up being non-HCICOs again.

And I know Alberta has been spending a lot of effort, a lot of time, a lot of research on CCS for their tar sands crude, and we think this is a positive movement.

As was mentioned today, too, we have a HCICO Screening Workgroup, and also HCICO's an agenda item for the advisory panel. So, I would say that we have several public processes going to address this issue. And, as you can tell, it's of concern to a lot of folks and we've been having a quite a few meetings on this issue, and we will continue to have full public process on this issue, as well as other issues with the LCFS.

Again, I think the fact that three-quarters of the crudes passed the initial screening, and there's potential for others, that I don't think the situation is as dire as Gordon's Death Valley slide would suggest.

I would -- Jim Uihlein mentioned the E85 report he's looking for. I'm going to go back to my office and inquire about where that report is.

We are also working on biodiesel and renewable diesel specs, fuel specs, and we think some of that had originally been scheduled, or still is scheduled for all, but the Low Carbon Fuel Standard is certainly taking up a lot of staff’s time.

I’d like to close by saying that, you know, again, I’m glad to get an update on these alternative fuels. I think that the LCFS certainly invites them. In fact, I think drives innovation.

And we do understand the challenges of meeting the LCFS and RFS2, and that we are working with stakeholders in several workgroups and panels to talk about the LCFS and see about the availability of fuels, and the cost of the fuels, et cetera.

And I think that through our processes and through processes like this there’s plenty of opportunity for input. So, thank you.

MR. OLSON: Thank you, Mike. I know we have a meeting scheduled with your staff at some point here, and the Commissioners, individual Commissioners here, in the near future, just to get a little better understanding of the Low Carbon Fuel Standard status.

And one thing that, and maybe I’ve lost track of this, but would be helpful for us is to -- if you have any comments on expectations for drop-in biohydrocarbons, the so-called long chain bihydrocarbon, whether you have pathway studies? It's been kind of a dearth of information for us, for our records here, and wondered if you had any comments about that?

And I have one other question, too.

MR. WAUGH: I know there's been some discussion of butanol but, in general, I don't think we've had a lot of people come to us with any types of drop-in fuels like that. We certainly have talked about renewable diesel.

But, again, with the LCFS being performance based, you know, if someone comes to us and says we've got a drop-in fuel, we want to consider that -- I mean we would, certainly. But to my knowledge, there hasn't been a lot of discussion right now on drop-in fuels.

MR. OLSON: Very good. And one other comment, question is this would be something we're interested in the future is a better explanation of the interaction of the Low Carbon Fuel Standard credit process and the upcoming cap and trade crediting for the 2015 rollout of that. And maybe there isn't -- that's not really described at this point, but we're interested in how that would interact.

MR. WAUGH: Yeah, there's been some initial discussion on that and, you know, with regard to credits for the LCFS, the regulation right now says that the credits can't be imported into the LCFS. But if you have excess credits, that you can export them from the LCFS if that program that you're exporting to accepts those credits within their own program.

I think there are some challenges with cap and trade, and challenges of LCFS, and in terms of how that gets rolled in, in 2015. There's been some discussion but for the most part it's -- we've been so busy working on the LCFS that we haven't had a detailed discussion on that interaction, but I think we would be able to discuss that in the near future.

MR. OLSON: Very good, thank you very much.

MR. SCHREMP: Any other questions for Mike, in the audience?

All right. Well, thank you very much, Mike.

I guess at this time, Tim, I guess I'll open it up to additional questions or comments from the audience?

MR. OLSON: Yeah, please, open public comment from any other questions, either in the room or on the WebEx?

THE REPORTER: Can you get to a mike?

MR. SCHREMP: I'll go ahead and repeat.

THE REPORTER: Okay.

(Whereupon a staffer reads a question from the internet, by Kathy Scales.)

MR. SCHREMP: Well, I think the question, I mean if I could summarize, is that there are different carbon intensity crude oils in Canada, and that some of the crude oil carbon intensities are actually not quite as bad as those of the thermally enhanced oil recovery of crude oils in California. And so, how can, I guess, not me justify -- I mean, I guess that's directed -- a question for Mike, how can there be justification for this?

I hope you've gotten to read the question.

MR. WAUGH: Thank you. Well, first of all, we're not banning any crude, tar sands crude, or otherwise. I think my point was to bring out that we have a function in the regulation that would allow CCS to be used if there was a HCICO, whether it was a HCICO related because it was thermally enhanced oil recovery, or bitumen mining, or whatever other types of reasons why it would be a HCICO, there's a way that you can drop the HCICO and become a non-HCICO through CCS. And that's really what was my point.

With regard to the basket, I mean when we looked to see that we need to reduce the carbon intensity of transportation fuels in California by ten percent, one would have to start with the baseline. And the baseline is, well, what crudes were the refineries running in 2006, and that was our baseline. So, as we move forward and look at other crudes, you know, I still think that there's a possibility a lot more of them will be designated as non-HCICOs. And once again, we're not banning any crudes. I'm just saying that the CCS is a tool, perhaps, to help a HCICO become a non-HCICO.

MR. SCHREMP: Thank you, Mike.

Jesse, do we have any other questions online? Okay, thank you.

So, I'll turn the microphone back over to Tim.

MR. OLSON: So, appreciate the comments, the panel members, the individual comments and presentations today. This is very valuable for us to have this information in our record and it definitely influences what policies are developed here by the Commissioners.

And there's some additional time to supply comments in writing, you said, is it May 23rd is the date?

MR. SCHREMP: That's correct, Tim, we'd like to have comments to the docket, in writing, by the close of business on May 23rd.

MR. OLSON: And could you also, Gordon, remind us, we have some other IEPR hearings on transportation-related things, is it on the forecast results and findings, is that -- I thought we had something planned in August or --

MR. WENG-GUTIERREZ: Yeah, so I think we have a plan of August 16th for our next workshop, where we will be talking about our draft document, and that's what would be in our final document, that would have anything in it, and should have our forecast, as well as all of the LCFS, RFS2 post-processing discussions that we discussed today.

MR. OLSON: And, yes?

MR. SCHREMP: And I don't want Malachi just to sort of understate that. As some of you may recall, our draft document from 2009 did consist of, I think, in excess of 250 pages, so there's a lot of stuff in there.

So, we will endeavor to get that to stakeholders as far in advance as feasible, understanding it's a lot of information they need to digest, to be able to come here and make comment on August 16th.

But there will also be opportunities to provide comment after that workshop into the record, once they've had more time to look at this But we're going to do our best to get that ahead to people as soon as possible.

MR. OLSON: And Gina Grey, you had another comment?

MS. GREY: Thanks, Tim. It was right on point to what Gordon just said that we would really appreciate something maybe a month in advance, like July 16th would be a great target date. Gordon? Because literally these documents are huge and I know you're saying we've got time after but, really, it's best if we could look at them enough in advance, especially we have a trade association, with many members that take a long time to look at these things. So, you know, to come to that workshop with something to say versus just sitting, it would be great. Thank you.

MR. SCHREMP: Yes, so I think the takeaway for me is that we go back to management and say that that's achievable with a one- or two-time review time by management of our document. I think then we can meet that, so -- but hear you loud and clear, it's a large piece of information and we do this every two years, and it's an important element of the overall IEPR, and so we will do our best to get that to all the stakeholders as soon as practical.

MR. OLSON: And just to also mention that we are -- reiterate that we are doing some follow up with the staff after this hearing.

And, Saul, do you have any other comments that you wanted to make for --

So, not hearing any other comments or hands raised, we are adjourning this meeting. Thanks a lot.

(Thereupon, the Workshop was adjourned at 5:19 p.m.)

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