BEFORE THE
CALIFORNIA ENERGY COMMISSION

In the matter of,	)	Docket Nos. 11-IEP-1C
	)	11-IEP-1K
	)	11-IEP-1L
Preparation of the 2011 Integrated	)	
Energy Policy Report	)	JOINT COMMITTEE WORKSHOP

Joint Committee Workshop on Economic, Demographic and Energy Price Inputs for Electricity, Natural Gas and Transportation Fuel Demand Forecasts

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

THURSDAY, FEBRUARY 24, 2011
9:00 A.M.

Reported by:
Michael Connolly

COMMISSIONERS PRESENT:

Robert B. Weisenmiller, Presiding Member of the Electricity and Natural Gas Committee, Chair

James D. Boyd, Presiding Member of the Transportation Committee, Vice-Chair

Also Present:

Susan Brown, Senior Policy Analyst (morning session only)
Tim Olson, Advisor to Commissioner Boyd (afternoon session only)

STAFF

Suzanne Korosec, IEPR Lead
Ruben Tavares, Electricity Analysis Office
Ross Miller, Electricity Analysis Office
Leon Brathwaite, Electricity Analysis Office
Chris Kavalec, Demand Analysis Office
Malachi Weng-Gutierrez, Fossil Fuels Office
Ryan Eggers, Fossil Fuels Office
Gordon Schremp, Fuels and Transportation Division

ALSO PRESENT (* Via WebEx)

Herb Emmrich Southern California Gas Company
Lee Bamburg, Sempra LNG
Rory Cox, Pacific Environment
Rich Ferguson, CEERT
Richard Aslin, Pacific Gas & Electric Company
Sharim Chaudhury, Southern California Edison
Philip Toth, Southern California Edison
Sierra Martinez, Natural Resources Defense Council
*Gina Grey, Western States Petroleum Association

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P R O C E E D I N G S

FEBRUARY 24, 2011 9:05 A.M.

COMMISSIONER WEISENMILLER: Good morning.

Let’s start the workshop today on the Joint Committee Workshop on Economic, Demographic and Energy Price Inputs for Electricity, Natural Gas and Transportation Fuel Demand Forecasts. This is part of our IEPR process. We are in the Transportation Committee. Vice-Chair Boyd will be here soon. We are certainly looking forward to a full and productive day.

Suzanne?

MS. KOROSEC: Good morning, everyone. I am Suzanne Korosec, I manage the Energy Commission’s Integrated Energy Policy Report unit.

Just a few housekeeping items before we get started. Restrooms are in the atrium out the double doors and to your left. There is a snack room on the second floor at the top of the stairs in the atrium under the white awning. And if there is an emergency and we need to evacuate the building for any reason, please follow the staff out of the building to the park that is kitty corner to the building and wait there for the all clear signal.

Today’s workshop is being broadcast through our WebEx conferencing system and parties need to be aware that you are being recorded. The audio recording will be posted on our website within a day or so of the workshop and you will have a written transcript available within about two weeks.

The Energy Commission is required to prepare an Integrated Energy Policy Report, or IEPR, every two years that assesses energy supply and demand, energy production, delivery, transportation and distribution and energy prices. These assessments form the analytic foundation for the state's energy polices that are recommended in the IEPR. The intent of the IEPR is focus on the most current energy issues that are facing California in an integrated fashion to provide a more informed evaluation of potential trade-offs when we are developing energy policies across different markets and different systems.

The purpose of today's workshop is to present staff's proposed analytic methods for the electricity, natural gas and transportation fuel demand forecasts, to discuss the modeling inputs and the assumptions about key demand drivers, and to get input from stakeholders on staff's proposed methods, inputs and assumptions. Our analytic efforts are coordinated among several offices, including our Demand Analysis Office, which forecasts statewide electricity, natural gas and use demand; the Electricity Analysis Office's Natural Gas Unit, which does long-range assessments of state, regional, national and global natural gas demand; and the Fossil Fuels Office, which assesses transportation fuel demand and transportation infrastructure needs.

Our format today is a series of presentations covering staff’s general approaches to the natural gas, electricity and transportation fuel assessments. Those will be followed by presentations on the economic, demographic and price assumptions that are used in those assessments. We will hear about natural gas and electricity this morning and we will hear about transportation after lunch.

After the presentations there will be an opportunity for public comment for folks here in the room and those of you listening in on WebEx. For those of you here in the room who want to make comments, please come up to the center podium and use the microphone so we can capture your comments on the record. And it is also helpful if you can give the transcriber your business card to make sure that your name and affiliation are reflected correctly in the transcript. For those joining us on WebEx, you can use the chat function at anytime or the raised hand to let the WebEx coordinator know you would like to ask a question or make a comment and we will either relay your question or we will open your line at the appropriate time.

I also want to note that we are accepting written comments on today’s topics and those are due by close of business on March 7th. 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 written comments to the IEPR docket.

So with that I will turn to you, Chair Weisenmiller, for any opening comments.

CHAIR WEISENMILLER: Well, obviously as we go into the IEPR process we have to look at the sort of inputs, the models and then the modeler's aspects. So today is starting on one of the building blocks, which are the input assumptions. And these will obviously have a major impact on the results and the good news is that we are coordinating across our various forecasts here within the commission but also trying to reach out to others so that we can have the best possible inputs and understand ultimately which of the differences are driven by the different model structures or by the input assumptions or by the choices that the modeler chooses among the models. So, again, let's have a productive day.

MS. KOROSEC: All right, we will start with Ruben Tavares.

MR. TAVARES: Good morning, Commissioner Weisenmiller. My name is Ruben Tavares and I am part of the staff here at the commission.

This morning Ross Miller, Leon Brathwaite and myself would like to provide you with an update on where we are in regards to a mandate that you gave us — well, actually your peers gave us — in the last three IEPR cycles. The mandate refers to how staff handles natural gas price forecasting in relation to the model and also the methodology. We will provide you with a brief history of our forecast and also EIA’s forecast as compared to actual prices in the market. Then after me, Ross will present a proposal on how to move forward for your consideration and also for your comments and inputs. Leon also will give a short description of some of the key drivers in the natural gas market that we are paying very close attention to.

On April 19th of this year, a couple of months from now, we will present to you results of a reference case that we will be using in the IEPR cycle. This will be the results of the model developed by the Energy Institute at Rice University, which actually was modified to accommodate our own needs here at the commission. We will bring also the developer of the model at Rice — that will be Dr. Ken Medlock — to explain to us the inputs, assumptions and outputs of the model. We will also invite on the 19th other experts in the field, such as professors from MIT, to give us also a briefing on how they see the natural gas market going.

In addition, we also would like to coordinate with the utilities and some of the stakeholders to help us proceed in the natural gas effort that we will provide for you in this IEPR cycle.

In addition to the 19th of April workshop, we are also planning another workshop sometime in August to give you results of different scenarios and sensitivities that we are going to be building up around the reference case with your assistance and your input. And with that I would like to proceed with my presentation.

Why do we forecast natural gas prices? Well, the reason we forecast natural gas prices is because we are mandated by law. The Public Resources Code indicates that we should at least every two years conduct assessments and forecasts of the natural gas prices in the market. The natural gas prices are used in different venues here at the commission for electricity demand forecast, they are also used for the transportation fuels forecast, for the design building standards, and some others here at the commission. We also receive requests from other state agencies and also the public for our own natural gas prices forecasts.

The commission in the past, until 2005, has actually adopted some of the natural gas price forecasts that we have generated. However, in 2005 commissioners expressed some concern about our forecast and they indicated so in the IEPR, where they directed us to look more carefully at our forecast methods in the 2007 IEPR.

In the 2007 IEPR cycle we attempted to better portray the uncertainties surrounding the forecast and we also generated some sensitivities around the reference case. Those sensitivities include at the time looking more carefully at the LNG facilities here in California and on the west coast. For instance, one of the sensitivities indicated that if we introduce a regasification facility in Southern California what will be the results of our forecast. We also expanded the LNG because at the time it was a very important topic. How can we expand also that LNG facility in later years, not just in Southern California but also in the Pacific Northwest.

Again we presented a reference case and we presented also these sensitivities to the commission. Nevertheless, the commissioners again expressed concerns about the forecast and directed us to evaluate the economic and physical characteristics of the model. Since then, actually since 2005 staff in conjunction with some consultants have been reviewing the models and the methodology of how we do the natural gas price forecast.

So in 2009 staff actually did not use the model to forecast natural gas prices or any other parameters. However, we focused in the 2009 IEPR on some of the main topics that at the time were very important, such as LNG, shale gas, pricing issues that were important at the time, infrastructure and natural gas storage. But again we did not forecast any natural gas prices. However, again commissioners indicated at the time that they were still concerned about us generating a single price forecast. And so they directed us again to continue researching our models and methodologies that we use to do this forecast.

So how have we done in the past before the IEPR was in place? Again, as you indicated before, inputs and assumptions are extremely important on our ultimate results. So at the time back in the 90s we, the staff, saw very strong growth in some of the areas that were producing natural gas such as the Anadarko and Permian Basins. We saw a big growth for them, also for very strong production and exports from Canada of natural gas, we saw very strong production in the Rockies. So at the time we were assuming that we will have enough natural gas for the next fifty years.

So how did we do as far as forecast? This graph we have the forecasts that we have for just three years, 1995, 1998 and 2000, plotted against the actual wellhead prices in the market. As we can see, we were actually forecasting very low natural gas prices and the prices in the market were quite a bit higher than we had forecast. And here are the assumptions that we had at the time in the model and then this represents only the reference case.

Then we have the 2000s, gas prices were increasing at the time and also we saw in many basins, you know, the decline of conventional gas production. However, we saw very strong indication that the McKenzie Delta and Alaskan pipelines were feasible at the time. Also we saw very strong indication that LNG was the way to go. At one point we had here in the state up to 13 facilities being proposed for regasification in California and also some in Oregon. Then in the last 2000s we saw a proposal to build Ruby, that has been coming and is going to be bringing gas from the Rockies, I understand, by June of this year.

So what was our record? Again just a few years here, 2003, 2005 and 2007 plotted against the actual prices. And again we saw in 2007, you know, there indication that gas prices would be a little bit higher than before. So this is plotted against, again, actual. And these are just the reference cases. So that was our record.

Now, this graph illustrates the forecast that EIA has done in the past — again, just the reference cases. As we can see, early in the 1980s EIA was forecasting very high prices. And again I apologize for some of you that have the black and white presentations, it is hard to see it. But here I think you can see how prices vary all over the place. EIA for a while now has been generating different scenarios and different sensitivities around the reference case. In the latest, actually the 2010, forecast they have 35 different scenarios where they assume either that we will have no shale production for the next 30 years to another one that we will have some shale gas production. So this is the record up to 2004.

Some of the assumptions in the 2000s that EIA had made, they were at one point seeing the decline of domestic production. And so a big increase in Canadian natural gas and LNG. Again at one point they predicted the Alaskan pipeline would be built by 2016. They saw strong demand for gas for power generation. Rocky Mountain production will be increasing in the lower 48. McKenzie Delta pipeline, actually, they saw the McKenzie Delta to open by 2010 and I don't think that's going to happen. I mean, it is already 2011.

Some of the assumptions in 2008 here, LNG imports will continue to increase, that's what they saw. Unconventional gas production from tight gas and sandstones will continue to increase also. But although they saw some increase in shale gas, they had never really taken very seriously the production of shale gas until the very latest assessment. They also saw imports from Canada declining.

SO what is the record for EIA versus annual average wellhead prices? Well, we can see they have — this slide represents prices from 2005 to 2010. High prices in nominal terms. So we have up to 2010 here and I think I have another graph – well, I will present the other graph in a minute here.

Then we have the year 2010. The EIA saw moderate growth in energy consumption given to problems in the economy. They also predicted in their reference case increase in use of renewables, a strong shale gas production but not as strong as they have seen over the last few months. No explicit actual regulation on greenhouse gases, that’s what they have in the reference case.

Then in 2011 they have an early release of their forecast. Now they are seeing lower US net imports of LNG, mainly due to the high prices in other markets outside the United States. Now they are looking at very little influence of the oil prices and natural gas prices, they are actually recovering dramatically. They say also delays as a result of offshore oil and gas drilling moratoria.

Back in 2010 EIA assumed in their forecast about 347 trillion cubic feet of technically recoverable shale gas. Just a few months later – actually the latest forecast that they have, 2011 – they actually doubled the increase of shale gas reserves to 827. Now, this assumption – I have seen this assumption several times. Just a year and a half ago I attended the Potential Gas Committee conference in

Lake Tahoe where we had some of the experts there indicating that the reserves of shale gas were very high. And actually the cost effectiveness of shale was a lot lower than we thought.

Actually at the time we heard from FERC that the cost effectiveness of shale was in the six dollars. Some of the experts in the room a year and a half ago were saying that they could produce at very close to four dollars per million BTU. So things are improving in this regard as far as the assessment of shale gas. Also EIA is now assuming that the Alaskan pipeline is not going to be constructed.

I wanted to make one correction on this graph. We don’t have the actual prices because this starts in 2010. So this shows the two plots of the forecast in 2010 and 2011. As we can see, EIA in a few months has actually decreased the forecast, predicting lower natural gas prices for the next 20 years or so.

What are others saying in regards to the natural gas market? We have, for instance, Bentek indicated in the last quarter – which is the first quarter of 2011 – that they see very strong gas production and they have seen a faster increase than they had expected. They also expect over the next few years – actually by 2013 – consolidation of exploration and production of the natural gas industry. They also see low Canadian gas imports.

However, in the latest assessment they are seeing that Canadian gas imports are very sensitive to prices and the Canadian gas will continue to arrive as soon as we have good demand and the prices are okay. They also see that the highest prices in other markets in the world will continue to hinder any imports of LNG to the United States, and they see this for the next four or five years. In addition to that, they predict that gas prices in the US for the next five years will not be over five dollars per million BTU. Again, this is the latest quarterly assessment that Bentek has done.

Navigant also sees very strong production from shales over the next couple of years. One of the reasons that they indicate why they see strong gas production is because the associated gas liquids have been selling at a very good price. And so they see gas production as a byproduct of these liquids in some basins. They also indicate that they have seen a lot of overseas investors in domestic production, domestic operations, that are contributing to this overproduction of gas. And they will see that continuing in the short run.

So how would we would actually like to move forward? Again, staff in conjunction with consultants has at this point thoroughly reviewed the methodology and models that we have used in the past to forecast the natural gas parameters. And we — again, in conjunction with management and some consultants — have presented this to some of you. We have concluded that the MarketBuilder platform that we have used in the past to build up the natural gas model was the appropriate tool, or was the best tool at this point to continue. We also concluded that the best way to proceed for the IEPR cycle is to use somebody else's model that has been already built and that can be modified for our own use. And that will be the model of the Energy Institute at Rice University.

(Vice-Chair Boyd arrives in the hearing room.)

Good morning, Commissioner. Good to see you.

VICE-CHAIR BOYD: Good morning.

MR. TAVARES: We also have concluded that staff must do a better job in portraying the outputs that we get in the model, the inputs, the assumptions, and also the uncertainties surrounding the forecast that we produce.

Because of, again, concerns that commissioners and management have expressed in the past about generating a single point forecast, staff is now proposing to develop some cases, some sensitivities, some scenarios that will be helpful to you.

So this concludes my presentation. Again, again, next Ross will give you a proposal of what we are planning to do in the next few months.

CHAIR WEISENMILLER: I have a few questions before you go.

MR. TAVARES: Sure.

CHAIR WEISENMILLER: The first one is: Have the staff systematically gone through and compiled from the SEC filings what the various shale gas producers say is their expected production? Obviously, SEC filings have large penalties for perjury so they better be accurate. Have you done that so we have a sense of what collectively the industry is saying is going to be produced?

MR. TAVARES: Actually we haven't seen this done as a specific task. But we will do it. Again, we are in the process of still accumulating some of that data. We have been talking to, again, the developer of the model. That is Dr. Medlock. And he is the one that has been putting some of those inputs into the model.

CHAIR WEISENMILLER: Okay, but one of the key inputs is going to be shale gas.

MR. TAVARES: Yes.

CHAIR WEISENMILLER: And so that has to be verified in some fashion. As you said, it's sort of degrees of optimism and pessimism.

MR. TAVARES: Correct.

CHAIR WEISENMILLER: And one of the data points I want to really verify, that input assumption, is what the industry is saying their shale gas production is going to be.

MR. TAVARES: Okay.

CHAIR WEISENMILLER: And the other question is: At one stage there was a lot of work, say, in due diligence where people used futures markets for price discovery, particularly in the short term. And the longer term tried to blend into these sort of structural models. Has the staff tried to combine those approaches of looking at futures for discovery in the short term? Obviously, futures indicates what the industry believes as opposed to necessarily a forecast. But, you know, again – because a lot of your oscillations tended to be looking at the early years for what are relatively longer term forecasts.

MR. TAVARES: My understanding – again, I wasn't in the unit at the time – but my understanding is that in the 2005 IEPR cycle we combined both the futures and also our own conventional gas, you know, to generate a forecast that the commission adopted. Is that correct, Leon?

MR. BRATHWAITE: Basically, yes.

MR. TAVARES: That's what we did back in 2005, that was the last time that we actually provided any suggestions and forecast to the commission.

CHAIR WEISENMILLER: Okay. But one of the other pieces of data I want to see is what the futures look like on this. Again, when people are making major investments they tend to look at that as part of the data. So again, I think we need to have that sort of information developed too.

MR. TAVARES: Yes. We will do that. And I understand also that CPUC is directing the utilities to use the futures.

CHAIR WEISENMILLER: Well, certainly if you look at the NPR, typically people start by looking at futures and then blending that.

MR. TAVARES: Yes.

CHAIR WEISENMILLER: And, again, if you're looking at major investments in production or pipelines typically you use futures and blend that to the longer term models.

MR. TAVARES: Okay, we will do that.

CHAIR WEISENMILLER: Okay, thanks.

VICE-CHAIR BOYD: I've been away from the Natural Gas and Electricity Committee for a little while now but lived through with you and other staff some of these debates about point forecasts and what have you. But moving over the shale gas subject, I think the Chairman's point is an excellent one. I have been troubled for some time about the shale gas estimates that had been made only in that I think they are incredibly optimistic – this is just me speaking – in terms of what will ultimately be realized. And I think what the industry is forecasting the potential is is definitely a point we need to know. And I think your source document is an excellent place to go.

But I still have my nagging doubts about whether we'll realize those potentials for a host of reasons. And so, once again, it makes it difficult to really know what the natural gas future is going to be. But I don't have a simple magic answer to what's going to give us a better estimate at the present time. So it's just another compounding issue.

I think the environmental issues that are being debated about recovery of some of the shale gas are going to be very problematic. Until that issue is resolved we are still going to be uncertain. Right now we are living — I've been through too many waves of feast and famine in the natural gas area in the time I've spent not only on this commission but during the crisis itself, the electricity crisis. Anyway.

MR. TAVARES: And —

CHAIR WEISENMILLER: Excuse me. The staff had mentioned earlier about having an upcoming workshop. And certainly one of the key topics for that will be shale gas.

MR. TAVARES: Uh-huh.

CHAIR WEISENMILLER: And certainly trying to pull in some of the recent MIT study I think will help us too, along with the industry.

MR. TAVARES: Absolutely.

And, again, I want to assure that we will be looking at that issue very closely. We can also — again, we will come back to with proposals and we can build scenarios around, you know, shale gas, either different quantities or no shale at all. So we will have the flexibility to do that.

VICE-CHAIR BOYD: You probably don't have to go so far as no shale at all. But anyway, good point.

MR. TAVARES: Okay, thank you, Commissioners.

CHAIR WEISENMILLER: Thank you.

MR. TAVARES: Are there any questions from the audience? Herb, you have some questions or comments?

MR. EMMRICH: Commissioner Weisenmiller and Commissioner Boyd, I am Herb Emmrich with Southern California Gas and San Diego Gas and Electric's Gas Demand and Gas Rates Manager.

I would like to comment on Ruben's presentation if I could. We are totally in support of scenarios. The uncertainty of gas price forecast both on the price side and on the demand side are always problematical. And the only way to capture that uncertainty is do to scenarios. So we totally support that approach.

We also support the use of futures. Futures are becoming more prevalent and, as you said, Commissioner, the industry locks in futures prices and even though prices may decline if they are locked in they will continue to produce.

On the shale gas issue, there is an abundance of shale all over the United States, Canada and the rest of the world. So it's not just here, it's called the Shale Gale in Europe. And the forecasts that are coming out from the EIA and there is also a study going on right now that we are participating in with the National Petroleum Council, which will issue a report probably in April or May, showing the use of natural gas to reduce greenhouse gas emissions. And shale gas certainly is a part of that.

Just a few years ago, five years ago, at some of the natural gas working group meetings we talked about running out of gas, so we need LNG. LNG at high prices, you know, seven or eight dollars a million BTUs, priced at the California border right now it is less than four dollars. So all the shale gas that has come online is reducing prices and the forecasts are for more to come on line.

Also you have the Ruby pipeline which will bring gas to California. And, as you know, our parent company Sempra Energy was a participant in the Rockies Express Line to take gas from the Rockies to the east. And lo and behold a few years from now it may be that that pipeline has to be reversed to bring shale gas to the west because there is going to be an overabundance of shale in the east. Alaska does not look like it’s a possibility anymore because of these low prices and the heavy government supports.

Overall, I appreciate the opportunity that we have to participate. We expect to fully participate both on the gas and the electric side. And we have had a very good working relationship with Ruben and the CEC staff on the natural gas working group. And we hope to continue that in the IEPR process.

CHAIR WEISENMILLER: Thanks, Herb.

A couple of questions I had, although I would note in talking to the governor we both remembered in 1977 the SoCal Gas expectation at that point that without LNG there were going to be hundreds of thousands of jobs lost in Southern California that year. So it is remarkable how these things go in cycles.

But you have to be struggling with the same issues we are of on the one hand knowing that there is a lot of uncertainty on the gas price but also that you somehow have to convert these, take an estimate and put it into your demand forecast models or into your other decision-making. How do you do that? I mean, obviously one potential is you take your high and low and take an average, the other is you try to come up with what you think is a reasonable base case. But, I mean, how do you struggle with those uncertainties?

MR. EMMRICH: You just have to run scenarios and try to develop a strategy that you can survive and prosper no matter what happens, to have a robust strategy. I have been in the industry for more than 35 years and you cannot forecast gas prices, that’s not possible. There is a realm of uncertainty and you have to try to capture that.

CHAIR WEISENMILLER: Well, that’s true. But I mean in terms of moving forward as we try to come up with a demand forecast or tell the PUC what to use, you know, we need to be portraying both the uncertainty and something that is usable. And so I guess I’m pushing you on how does SoCal do that balance between reflecting uncertainty and something that is really useful in decision-making?

MR. EMMRICH: Well, we have a base forecast. But around that we have a high and a low.

CHAIR WEISENMILLER: Okay.

MR. EMMRICH: And you have to deal with that.

CHAIR WEISENMILLER: And the base, I mean, how do you construct – I assume you try to do enough scenarios that you are relatively comfortable that the base captures the likely outcomes?

MR. EMMRICH: On the base gas price forecast we use futures and we use all the other industry forecasts from EIA, from the Energy Commission and from private sector companies like Wood McKenzie and so on. And we do a weighted average of those forecasts for our base.

CHAIR WEISENMILLER: And in terms of futures how far out do you go?

MR. EMMRICH: As long as the futures market exists, for six years on the NYMEX.

CHAIR WEISENMILLER: Okay, so you use NYMEX, you don’t look at some of the individual contracts?

MR. EMMRICH: No, we look at NYMEX.

CHAIR WEISENMILLER: Okay.

MR. EMMRICH: Thank you.

CHAIR WEISENMILLER: Thank you. Go ahead.

SENIOR POLICY ANALYST BROWN: This is Susan Brown. Herb, I had a couple of questions for you. What is your company’s view on the role of LNG in the near term and can you comment on the status of the project that you were involved in below the border?

MR. EMMRICH: That’s a very painful question. Of course, like everybody else in the industry five years ago we were thinking we were running out of gas and we have over six-million gas customers in Southern California. So to safeguard that the parent company built an LNG facility in Baja California. That facility is used very sparingly because, as Ruben pointed out, internationally LNG is priced according to oil prices. So in Japan LNG is nine or ten dollars a million BTUs, in Korea and so on. Whereas, the border price now is four dollars. So we are not attracting very many cargoes. Random cargoes looking for a home will land there and we also have a complex with the Mexican electricity department. So some gas has to be delivered there and it is and they are buying that.

The thing that is changing now is several gasification owners are looking to export LNG out of the United States, to use all the shale gas liquefaction facilities built at the current regasification facilities after export. Some LNG has already been exported. But that is LNG that has been brought there, stored in the US, and then re-exported. But now companies are asking to actually put liquefaction facilities in, as is Kitimat in Canada. So that's what has changed.

SENIOR POLICY ANALYST BROWN: I just had one last question. What is your view on the effect of rising oil prices on gas futures? It is likely a short-term phenomenon but nevertheless a real one.

MR. EMMRICH: Well, in the US there seems to be a total disconnect with oil prices because there is so much gas-on-gas competition and more gas coming online. So the thing that may change that is gas-to-liquids projects. In other words, you can make diesel, high quality diesel, out of natural gas. And that would be cost effective at this point. I’m kind of surprised that the oil companies and the gas producers are not looking at that.

SENIOR POLICY ANALYST BROWN: So as I understand it you’re saying that Fischer Trope produced gas is competitive at higher oil prices?

MR. EMMRICH: Right. I mean, oil prices are ninety dollars and I guess currently in the short term over a hundred dollars a barrel.

SENIOR POLICY ANALYST BROWN: Right.

MR. EMMRICH: And certainly that is cost effective.

SENIOR POLICY ANALYST BROWN: I think it was 110 the other day. But, yes. Thank you.

VICE-CHAIR BOYD: While you are there and since gas-to-liquids came up, it’s been my recollection that there is quite a bit of activity in converting Middle East gas to gas-to-liquid, primarily to take it to Europe because of their heavy dependence upon diesel fuel and what have you. And I presume that will continue to be fairly attractive, although not as great as they thought it was maybe five or six years ago. Nonetheless, that’s always the possibility. But it’s never been very attractive here in this country. We don’t rely on diesel fuel quite like Europe does and we have been living off their gasoline to some degree.

A quick question about renewable natural gas, which has been something of great interest the last – well, the last year if not longer. A new term, we used to call it Biogas, but now renewable natural gas seems to have finally stuck as going to be the formal term. Does your company see much activity in that arena in the near term?

MR. EMMRICH: Well, we have actually put in place a conditioning plant in Escondido at a sewage facility that already has a gas recovery system and they were cleaning that up to pipeline quality gas. So the technology is working but the price, of course, is extremely high, it’s 12 to 13 dollars a million BTU. But if you look at renewables compared to photovoltaics, if you use that natural gas and price it against photovoltaics then that price is competitive.

The biogas would not be competitive with natural gas produced out of shale formations, for instance. So you are looking at four dollar gas at the California border and this biogas would be in the 12 to 13 dollar range. Unless it’s a very, very large facility that already has a recovery mechanism, then the prices could be much lower than that. But again, what is the comparison? Do I do photovoltaics or do I do biogas? And there may be some competitive options on the biogas side.

VICE-CHAIR BOYD: Right, because RPS credits are given for the use of renewable natural gas and electricity generation. It levels the cost playing field a little bit in that case.

MR. EMMRICH: Right.

VICE-CHAIR BOYD: Okay, thank you.

MR. TAVARES: Any other questions or comments?

MR. BAMBURG: I will try to be quick. I didn't intend to speak. I am Les Bamburg from Sempra LNG. And I did just want to clarify on the ECA facility. The ECA facility is fully contracted. So whether cargos come in or not we collect money. So I just wanted to clarify that that was the case. Half the capacity is contracted to Shell/Gazprom. They haven't brought any cargos in but they pay for the capacity. The other half is controlled by Sempra. We have a long-term contract with Tangguh LNG. And under that contract, which is roughly 500 million a day equivalent, they can divert up to half.

So there is half that continues to come in and, as was commented, part of that or a majority of that goes to serve the CFE contract but the remainder is available for delivery to other markets.

CHAIR WEISENMILLER: Okay, on average how many shipments come in to that facility per year?

MR. BAMBGURG: During the majority of 2010, starting with March – because the Tangguh facility was delayed in its startup but once it was kind of fully up and functioning – we've been receiving cargos for the majority of 2010, you know, roughly every 12 days.

SENIOR POLICY ANALYST BROWN: And how much of that gas is being used in California in your service area?

MR. BAMBURG: I don’t have an exact number. I would say the majority of that is consumed by CFE and also our affiliate owns the generation plant at TDM, so it goes there. But I don’t have a number. If that is something of interest we can certainly develop some information around, say, for 2010 how much actually was delivered to the United States.

CHAIR WEISENMILLER: That would be good.

MR. BAMBURG: Okay.

MR. TAVARES: For those of you that might be curious about what ECA and CFE are, Energia Costa Azul is a regasification facility located in Ensenada. And CFE is Comisión Federal de Electricidad is the national utility of Mexico.

MR. COX: Good morning. My name is Rory Cox from Pacific Environment. This issue of LNG exports, I don’t think, is one that should be underestimated in terms of an input that could really impact natural gas prices. When you look at what’s going on with the Kitimat facility in British Columbia, Sabine Pass in Texas, and talk of other LNG projects that were ostensibly built to import, now talking about flipping to export. When Japan is paying 12 dollars per unit for natural gas and we're paying four dollars and you are a natural gas producer, obviously you are going to sell to Japan. So I think that could have a big upward impact on our natural gas prices here in order to compete with that world market.

And it is really a sea change in terms of what we are doing with energy in this country. But I don't think that should be overlooked or underestimated in this exercise. Thanks.

MR. TAVARES: Any other questions or comments from the audience.

(No response.)

Anybody on the internet?

(No response.)

Okay, thank you very much.

MR. MILLER: I'm Ross Miller with the Electricity Analysis Office. I see a name plate has appeared. I'm only going to be here five minutes, I hope for budgeting purposes that is not considered a googah because it's got my name all over it.

I have just eight slides and we've already actually talked about the contents of a number of them. I also have a handout, which is a chart. And it's essentially a picture of slides five, six and seven. Or slides five, six and seven are a description of this chart. Either way they go together. I’m not going to try to show that chart on the screen, it’s just too small.

I’m going to be talking about the modeling portion of the overall gas assessment. In addition to the modeling, the gas assessment is going to include our analysis of current market trends, what other entities out there doing the same thing are saying, their reports, their analyses. And also what is going on in the sphere of activities that gets you from what the model results are, which is basically a wholesale market, to the retail level, which would include a lot of the transportation cost or activities that will manifest itself in gas prices through what is essentially an add-on to the model.

I’m not going to read through all these purposes. The main thing I did want to point out, when I get to describing the scope and nature of our modeling I will identify the specific purpose that we are using to either select that case or build the assumptions that basically differentiate that case from the other cases.

The workshop is noticed for demand forecasting. When we’re talking about the demand for natural gas we have to think about both the end use gas demand, the end use electricity generation demand, because that is served by gas as a marginal resource. And because burning gas in generators is a marginal resource for generation we also have to consider all of the alternate electricity supply options that might displace gas as the generating fuel. So it just adds another level of complexity to what we are trying to achieve here.

Obviously, our modeling is going to involve a model. Later you will hear about the Demand Analysis Office demand forecasting, they are using models for that, and the Transportation Office will use models for their effort. So from here on I am necessarily limiting what I am talking to about our use of the model.

Ruben explained the process we went through to confirm that the world gas trade model is the model we think is best used for these purposes. I am not a gas expert and I'm certainly not a gas modeler. So everything on here has been told to me and I accept it on faith about the model. The thing I would focus on as a non-modeler is that the last bullet there, that the model will give you something it calls a price. Whether we use that price as a forecast of what is going to happen in the future is entirely up to us. And there have been a lot of comments about being careful if that is what your plans are.

Essentially what it is, it's the price that would have to be sustained to make all the investments that the model chose to make with its internal logic thinking that they are economic under all the conditions that you assumed in that particular run. And there are thousands of assumptions that we have to make about future conditions of the drivers of gas demand, supply and resulting price. And they are all complex and interacting. So it is quite a challenge. So I think Herb got it right when he said it is very difficult to do.

So what is the use of modeling? It's basically to provide insights about potential market outcomes under a bunch of different conditions. So we can't do experiments out in the real world but we can with our model. And the trick is to design those experiments in a way that you can get useful insights out of them. And that takes making some predictions, plausible assumptions about future drivers. And if you assume that the model algorithms are all correct and not too much of a simplification of the world then you can say, well, under these conditions this could be the price.

Another thing about the model is, when Ruben went through his survey of initial gas price assumptions that we might use as inputs to demand forecasting he was pretty much constrained by the number of entities, people, companies that even do forecasts like that. Of those, how many make them public? And of those, how many assumed either – were done for a purpose of which we are interested or assumed conditions like the ones we think are interesting to assume.

So it gets to be a very narrow set of other’s work out there, all of it enlightening, all of it a potential source of insights. But the advantage of having a model is we can come up with customized prices that are customized to questions we’re interested in and assumptions about future conditions that we are also interested in.

I have three slides basically going over some of the cases we are initially proposing to do. Overall we are focusing our assessment on cases we think are helpful to decision-makers. That’s basically why we are here. Rather than having a single point forecast as the primary product when we are all done. Commissioner Weisenmiller, your point is well taken about, well, you have to make a decision, you may need a number. I’m going to talk about that in my last slide. Absolutely the reason we are here to help inform that decision-making.

I split these into three parts. The first part here is primarily what happens with price is not determined by what happens in California. It is much more that world and regional drivers affect that. Obviously, what happens in California can affect price to some degree, so we are not ignoring that completely. But these first two cases would be designed to address a question of what vulnerabilities or opportunities California is facing with regard to future prices. And so these cases – that’s a question, why we selected these cases.

It’s basically a bounding analysis. The challenge is to build up the assumptions about the real world future conditions that are plausible, not wildly high or wildly low, but plausible individually and also in combination. And that’s part of the area where, through the comments here today and especially written comments – I guess due March 7th – any help with that will be greatly appreciated.

I should say that in this cycle with this model or platform we are only capable of and have data to do annual modeling. So we are not going to be able to do seasonal or monthly, we are not going to be able to do operational modeling, we don’t have the data or can run this model in that mode right now. So that necessarily puts some limits on what we are going to be able to discover and in some sense drives our selection of the questions that are appropriate for us to be focused on. The source of the questions is not anything new. It’s basically an interpretation of what the IEPR statute says should be in the gas assessment that is directed to be part of the IEPR.

Part two is, there is a lot going on in California that would affect the demand for gas. And through whatever price you assume our exposure to cost of gas. Not only that but the flows, whether the infrastructure is adequate, and other impacts of the natural gas system demand and use. One might be the emissions, climate change emissions. So these cases will focus on what is going on in California that drives demand for gas and our exposure to cost and those other performance indicators.

We will construct those case. This model will – I didn’t go over the point in the earlier slide, but it is a general equilibrium model that will iterate between demand and supply. There are supply cost curves, demand curves, and the price is basically discovered. It’s a capacity expansion model in the sense that if it starts to see a wide disparity between price, between demand and supply, and it knows that there is a potential pipeline that can be built there – we haven’t constrained it to not do that – it will build a pipeline if it sees that the economics are right for that.

So we will have that feature turned on when we create these cases. Because that is basically the way people decide whether or not to build these pipelines. And a lot of the conditions, some of those many thousand assumptions would be average temperatures, average rainfall, which affects hydroelectric generation, which affects the amount of gas generation you need, which affects gas demand. Those will be under average assumptions. But then we need to do sensitivities on those systems because at any given year you can experience situations that are more stressful to the system that you wouldn’t assume when you are deciding whether to invest in the infrastructure. Nevertheless, you still have to suffer through them when they happen. So we will do sensitivity cases that stress the temperature, hydroelectric conditions and possibly even economic conditions.

These two sensitivities are basically designed to avoid falling victim to the too rosy assumptions that you were talking about earlier. So you can see all through the trade press of how abundant and cheap it looks like shale gas was going to be, you can also see a lot of concern about the environmental impacts. So this is a challenge to put together. To do shale gas production safely what might it take in terms of increased costs of production, getting the cement just right. You know, whatever it takes. Or possibly areas being constrained as no development areas. So this is necessarily dependent on getting some plausible information about what those costs might be. It is relatively simple to add the cost into the model and see how it changes supply/demand flows and price.

The other one is to look at the either long-term infrastructure planning and market impacts of widespread pipeline integrity issues. So this also would be subject to availability of data on pipeline integrity. Pressure is not something that is simulated in this model. We would have to go from pressure reduction to capacity reduction. And we need to understand how segments of pipeline in the world that might be constrained are represented in the model if there is a one-to-one relationship, if it makes any sense to do this. So we are kind of in an early stage of exploring doing these cases. It should be seen as just a broad brush approach. As I said earlier, it is not any attempt to look closely at operations of the pipeline system under varying conditions of pressure or outages for repair, replacement or pipelines.

So, as I said before, we are interested in comments in helping to build the assumptions. The chart I mentioned earlier, the rows in that chart are basically the categories of drivers where we think we will be making different assumptions in each case. So the differentiation across those drivers is basically what will define the cases. And the way that chart is constructed, it doesn't necessarily have a world gas trade model variable indicated in it. But it is something that you have to make an underlying assumption about, say, the amount of renewable generation you expect to serve California demand that we can trace through the interconnectedness of the systems, the gas and electricity system. We will find an assumption in the world gas trade model that would have to be altered to represent that future condition.

This last slide, as I said, we have hit on some of these topics. We are doing this work to help decision-making. There are specific purposes for which people in California are making assumptions about the future price of gas or adequacy of gas infrastructure. And we are here to help with that effort.

Just stepping back a little bit, the reason it is important is that, number one, it’s complicated. There is a balance between competing objectives usually: reliability, cost, environmental protection. And because, as I think everyone is aware, the future is very uncertain, that means any decision you make based on a presumption about the future carries some risk with it. So what we think is the best approach is to try to understand what those risks are and think of it that way. The risk of using this number for a particular decision, to help you decide what is a prudent assumption to use for that purpose.

So you mention using future prices for the early years and then fundamental models for the out years. That is an example of doing this. You can't get the futures price out of our model. You have to understand at a higher level what you are trying to achieve and what the risks are and that’s what leads you to taking that approach.

CHAIR WEISENMILLER: So in terms of questions, I want to make sure that we do have a base case or reference case that we can use along with the sensitivities coming out of this.

MR. MILLER: Yes. I didn’t include it in my slides but it is on the chart. And Ruben referred to it. It is the Rice University case, it will be delivered. They will call it a reference case. We don’t know right now the status of that case in our overall design until we get it delivered and understand it. We need to understand the conditions that he’s assumed in it and the approach he took to making all of those decisions about these thousands of uncertain variables.

CHAIR WEISENMILLER: Well, again, but on the uncertainty part, I guess, the thing I would stress there is – I know at one point I did an event tree model that looked at gas demand in the west, looking at temperature throughout the west, looking at outages, hydro and all that, all of which affect things. But as you’re going into that sort of uncertainty you have to weigh things by the probability. And so as you go through these, you know, at least at that point – I think it was in 48, it was an incredibly cold year in the west, it was the coldest year in 50 years, the coldest single month in 50 years was in ’48. Now obviously if you use that as your high case and didn’t take into account the probability of it you would have an incredibly high number.

MR. MILLER: Right.

CHAIR WEISENMILLER: So anyway you have to be bounding these things by what's – and similarly if you go to the driest year in history or the wettest year in history, again you can do that but you have to fold in the probabilities of that to make it useful for the decision-makers.

MR. MILLER: Right, I agree a hundred percent. And where we have a history of well characterized distribution we can look at the probabilities and apply them or have them influence our judgments about how to use the case. But a lot of the inputs we have absolutely no –

CHAIR WEISENMILLER: Yeah, but on the other inputs I think what you tend to find is, in terms of statistical mechanics there is something called the Central Limit Theorem, which is if you have a lot of different variables, all of which are variable, that the mean tends to still dominate the overall distribution. If you start thinking about the probability distribution from the various variables you might have some that are extremely high but that is offset by something that is extremely low. So, again, statistical mechanics it typically comes out at the mean, even though there is a pretty broad distribution. You see that in chemical kinetics, things like that.

MR. MILLER: Right. When we are doing the assumption selection or assumption building, I call it, we will be taking all of this into account that we can. I think that requires – well, I am a biologist, not a mathematician so I wont give you my understanding of the Central Limit Theorem. But I think it might be independent variables with random distributions and all the same distribution. And I don't think that's what we have in the gas and electricity markets.

But there is nothing here to preclude combining all those approaches when they are feasible and useful. I mean, that's our overall philosophy. Because ultimately we can give you 20 cases but it may be someone's judgment, well, which is more likely? And so whatever information that we can provide to address that question we think that is part of our job to do.

CHAIR WEISENMILLER: Great. Thanks.

MR. MILLER: So just to finish up here, the approach here is to moderate the risks of the decision-making using a particular number for a particular purpose. So the best way to do that is to understand the ranges of the forecast and what the consequences of those decisions might be. And so that sets the job at basically prudently selecting the forecast that gives you that performance. So basically what Herb was saying when he said coming up with a robust policy, it may not be optimum under every condition but you basically can tolerate the results under a wide variety of future conditions that you can't either predict or control.

I didn’t include in the slides, but I would like to give a reference to a very good paper that I think is really on the point of this slide and how it can actually be done. It was the National Regulatory Research Institute paper from May 2010 by Ken Costello. It is called “Looking Before Leaping, Are Your Utility’s Gas Price Forecasts Accurate?” I think it is a very good paper because it’s basically the regulatory community’s think tank. And so they are writing to you guys. And I think it is a very useful paper.

CHAIR WEISENMILLER: Yes, why don’t we docket that? Why don’t you put that in the docket.

MR. MILLER: Certainly.

CHAIR WEISENMILLER: Thanks.

MR. MILLER: So if there are any questions.

CHAIR WEISENMILLER: I covered mine already.

MR. MILLER: Okay. From the audience?

(No response.)

Uniform universal agreement?

(Laughter.)

There we go.

CHAIR WEISENMILLER: I wondered what it would take to get you out here, Rich.

MR. FERGUSON: I am Rich Ferguson and I am the Research Director at CEERT and in recent years have been worrying about electric transmission decisions. And, of course, decisions about gas infrastructure are very similar. And I guess my comment, I'm really curious to see how the infrastructure scenarios play out vis-à-vis prices. I mean, my gut reaction is that there is a lot more that's influencing gas demand in California than price. So I would be surprised if you find very much difference in gas demand with, you know, a couple of dollar change in gas prices.

And it seems to me that your plan number two, which is looking at basically policy uncertainties and are probably the biggest driver. And those are things that are just very difficult to use your statistical mechanical approach on. I note that the ISO is using a case where they are assuming that the once-through cooling regulations will eliminate the nuclear power plants and they will be replaced by gas. And you are talking about something like 40 terawatt hours of gas by electricity in that scenario. And as far as I know there is no mean value theorem that is going to tell us what the water regs are going to do to the nukes.

So I'm not quite sure how you're going to scenarialize that kind of thing.

CHAIR WEISENMILLER: But, Rich, the basic question is what percentage odds would you give for that?

MR. FERGUSON: Personally? Slim and none.

CHAIR WEISENMILLER: So, yeah, I'm looking for those sort of reality checks on the high or low cases.

MR. FERGUSON: That is an extreme case, I think. But, I mean, there are many more sort of policy issues that I think would influence the demand much more than price. And they are very difficult to get a handle on to try to say, well, is this more likely than that. And nukes is not one of those.

So you are going to have to struggle with it, there is no easy answer. In the end it's going to come down to this kind of, you know, judgment call. But I also agree that there has to be some kind of consensus on a most likely – we call it least regrets – kind of approach. Because sooner or later you have to make a decision. Are you going to build this pipe, are you going to build this wire or aren't you? So it's difficult.

And I think that plan number two is going to be a thorny one for you but I'm looking forward to the discussion.

CHAIR WEISENMILLER: I don't know, you may have had the opportunity to be at the IEPR workshop when I was on vacation?

MR. FERGUSON: No, I missed that one.

CHAIR WEISENMILLER: About the uncertainty. But we tried to focus on the economy. On the gas world I think we are very focused on the gas shale question. But looking at more the demand forecast, trying to understand where the California economy is on this, you know, bouncing back is what I think is one of the bigger uncertainties on the demand forecast per se.

MR. FERGUSON: I don't disagree a bit. I mean, when we are looking at the electricity demand forecast out of the 2009 IEPR, and of course there were people saying that's too pessimistic, that's too optimistic. And of course now we see it was probably on the optimistic side. So this year's number I'm sure will be lower just because people aren't as optimistic about a quick recovery as they were a few years ago.

Anyway, that was just my comment, that I think you need to focus on plan two. I'm not so much worried about, you know, how the gas price forecast is going to influence demand. There is just a lot of other stuff going on.

CHAIR WEISENMILLER: Okay, thank you.

Since we have Herb here I guess the question is: What sort of elasticity is SoCal seeing in its demand for gas for price?

MR. EMMRICH: Elasticity is 0.1.

CHAIR WEISENMILLER: Okay, 0.1. I don't know if that is consistent or inconsistent, say, with PG&E.

MR. EMMRICH: I would think they would have exactly the same thing. Because you can't fuel switch in California. If you were able to fuel switch on the industrial side it would probably be like 0.2 to 0.3.

CHAIR WEISENMILLER: Okay, thanks, Herb.

MR. MILLER: I would make one last reference to the chart. In the center of it is a commercial for our April 19th workshop, where all will be revealed including the price elasticities that are in the world gas trade model that Ken Medlock has developed.

Any questions online?

(No response.)

Okay, thank you.

MR. BRATHWAITE: Commissioners, good morning. Susan. I hope everybody is doing well. I am Leon Brathwaite. I work in the Electricity Analysis Office.

What I want to do today is just give a brief presentation of the key drivers in the world gas trade market. Now, Ross mentioned that it’s a general equilibrium model and he talked about the methodology which we are trying to implement. And I am just going to talk about one of the tools that we will be using, probably one of the major tools, I should probably say, that we will be using.

The World Gas Trade Model we have been using for probably about ten years now. Previously we used the North American Regional Gas Model, commonly known as NARG. I think you all are probably familiar with it. The World Gas Trade Model is constructed in a platform known as MarketBuilder. And MarketBuilder is owned by Deloitte MarketPoint and we license it here at the commission. So let me just try to give you one of the key drivers in this model.

Now, I am not going to present any numbers today. We will on April 19th, as both Ross and Ruben indicated, be presenting all our numbers, all the inputs and the outputs and all that good stuff. What I want to do today is just lay out to the commissioners and to the audience what are the key drivers in this model that we are using to do the assessment.

So key driver number one is the resources assessment. Now, the first question that we have to ask when we are looking at the natural gas world – maybe in any world, I would imagine – is how much of our resource is available. And we normally put this resource into two categories, either they are proved or potential. Proved is what we have a very good handle on, we know about it, we understand its production characteristics and all that. Potential is we know a little less about it but it could become proved at some point in time within the World Gas

Trade Model. So that is our first question we have to answer, how much of this resource is available.

But the next thing, which is as important, is at what cost. I mean, a very good example of this is shale. Ten, fifteen years ago, thirty years ago, even when I was working in the industry thirty years ago, we always knew shale was available, it was abundant. But we didn't have the technology to extract it. So now technology has come along and has transformed shale from an unavailable resource to a way that it is now abundantly available. So what has happened is that technology has created a new cost profile. So those are the two questions on the supply side that we must answer, how much is available and how much can we economically and feasibly recover? So those are the two main drivers in that regard.

On the demand side in the World Gas Trade Model we have four disaggregated sectors represented. We have residential, commercial, industrial and power generation. We also along with all of these sectors have inputs to each one of the sectors, varied inputs. We must have a reference price and a reference quantity. You can think about those things as initial starting points for our modeling. Along with those reference prices and quantities you must have some elasticities. And those elasticities come from some functional form that was developed by Dr. Ken Medlock, who

Ruben mentioned.

He developed four general functional forms with independent variables. In the residential sector we have weather, population, natural gas price, income and heating oil price. In the commercial sector we have weather, population, income, natural gas price and also heating oil price. In the industrial sector we have industrial production, weather and natural gas price. And in the power generation sector we have total electricity generation, weather, natural gas price, fuel oil price, renewable electricity generation and coal price.

Now, these things are done offline. The model does not accept these things as parameters. We do these things offline to develop the reference prices and the reference quantities, we get the elasticities, we load all of that into the model and then we allow the model to do its work, do its crunching, its iterations. So those starting reference prices and quantities are then changed as the price within the model changes accordingly.

Another key driver is gas substitutes. In some areas of the world, in some areas of the lower 48, we have oil competing with natural gas and that is represented in the model through some cross-price elasticity. Also we may have some backstop in the sense that we may have some new technology that is available that may come on dependent on the price that is generated within the model. So those things are also represented in that form.

The other thing that is important also is any policy parameters, any policy assumptions that we make. Now, policy assumptions are very tricky in the sense that it is only to the extent that we can quantify these things that we can include them in our analysis. For instance, supposing there is some policy that comes about that says we limit shale because of environmental concerns. We can quantify that, we can put that into the model. Or if, for instance, we say there is some new cost of compliance with maybe some environmental regulations, that can be quantified, we can put that into the model.

On the demand side, suppose there is some policy concern in carbon regulation maybe, for instance, coal plants will be shut down. We can quantify that and we can look at the effects upon the natural gas demand, we can put that into the model and try to get some insight as a result of the policy. So policy parameters can also be included.

Another thing that is important also is investment parameters. What investment parameters do we use? Well, we have interest rates, taxes, royalty rates, all of these are important, all of these make some determination about the feasibility of any new construction or any continued production. All of these things are important in terms of the economic feasibility of that project.

Now, the last assumption, the last key driver within the model is the availability of infrastructure. Now, we have supply and we have demand and obviously it must be connected through a pipeline. Or if not a pipeline certainly a ship on the water. So the question then becomes when will those corridors be available to us. So this is very, very important. For instance, right now the Ruby pipeline is under construction. We have to at some point in time put it into the model and allow it to flow and allow that link to flow gas. Now if we put that in for 2011 it will have one effect upon prices, if we put it in for 2012 it will have another, or 2013 it will have another.

I mean, a good example of this was what we are doing with the Alaskan pipeline. At one time we thought it will come in at 2015. Now it doesn’t look like it will ever come in. But we had it at 2015 at one time, we had it at 2022, now it’s – I mean, I don’t even know if it is even under consideration at this point in time given all the development we see in shale gas.

But anyway, these are the key drivers within the World Gas Trade Model, these are the main drivers. There are others but they are not as important as these. On April 19th we plan to show all our inputs, all our results, all the things that affect the modeling and all the things that go into producing the price tracks that we will develop. Both price tracks and all the demand outputs and all supply outputs, all of these things will be represented in our April 19th workshop.

And with that I will close off my presentation. And if there are any questions from the commissioners or from the audience I will try my best to answer them at this point in time.

CHAIR WEISENMILLER: Thanks, Leon. I had a couple of questions. One of them is: In terms of the econ demo part of that, how much of that is sort of stock national and how much, at least for the California part, can be fine tuned for our current situation?

MR. BRATHWAITE: Fine tuned in terms of the time or fine tuned in terms of the region?

CHAIR WEISENMILLER: Well, basically saying I think our economic situation is weak.

MR. BRATHWAITE: Right.

CHAIR WEISENMILLER: And I’m trying to make sure that that weakness is reflected in the world model as opposed to necessarily saying here is the national part, which might be overly optimistic or more pessimistic than California. But let’s at least get the econ demo part correct for California.

MR. BRATHWAITE: The model is regionally divided up. California is a separate region, Nevada is a separate region, and so on. So there are specific economic, demographic information for each of those particular regions. So in California, as you correctly mentioned, commissioner, right now our economic situation is somewhat weak, for want of a better word. And to the extent that that will affect natural gas demand, that will be reflected in our demand inputs.

CHAIR WEISENMILLER: Okay.

MR. BRATHWAITE: So we do take that into consideration, yes, absolutely.

CHAIR WEISENMILLER: And they are going to be similar to what is used in the overall demand forecast?

MR. BRATHWAITE: Yes.

CHAIR WEISENMILLER: Okay. So the next question is, in the earlier discussion, I think we were talking about the decoupling of oil and gas.

MR. BRATHWAITE: Yes.

CHAIR WEISENMILLER: And trying to understand how that is reflected in this model.

MR. BRATHWAITE: Well, the connection between oil and gas is connected through a cross-price elasticity. So if there is any effect from the consumption of oil that cross-price elasticity will capture it as much as humanly possible.

CHAIR WEISENMILLER: Okay. And finally, in terms of either cost of capital or social discount rate, trying to understand how important that is. I assume if the cost of capital is lower you have more pipelines built.

MR. BRATHWAITE: Yes.

CHAIR WEISENMILLER: Or more investments. While if it’s higher you will have fewer.

MR. BRATHWAITE: Yes, that’s correct.

CHAIR WEISENMILLER: But, I mean, in terms of – do you have any sense of what the assumptions are there? Again, I would suggest one of the things to focus on in a workshop is that sort of discount rate cost of capital question in terms of what is the right number to use there and how does it affect the outcomes.

MR. BRATHWAITE: Well, to be honest, commissioner, the model does not capture anything about the social discount rate, it does not do that at this point in time. Obviously, those numbers are not cast in stone in any way, shape or form. And if we believe that those numbers should be changed to reflect some social premium or anything like that we could change it to reflect that.

CHAIR WEISENMILLER: Well, I just want to make sure that we look at what is in there in the workshop and try to make sure that they are reasonable.

MR. BRATHWAITE: Absolutely.

CHAIR WEISENMILLER: Okay.

MR. BRATHWAITE: The reference case, which will be delivered to us sometime this month, before the end of this month, myself and some of the other staff will be digging into the weeks, shall we say, in terms of looking at what is in the model, what are the results from those inputs, and we will at some point in time be ready to present that to you and the other members of the committee.

CHAIR WEISENMILLER: Okay, that will be good. I think for this type of model, if you look at the theory, the social discount rate has a big impact on the future cost of gas. So that’s why it is important to really focus on that.

MR. BRATHWAITE: I will certainly keep that in mind, commissioner, and take it into consideration in our deliberations.

CHAIR WEISENMILLER: Okay, thanks.

MR. BRATHWAITE: Questions, comments?

(No response.)

Thank you very much.

MR. MILLER: I’m just reappearing this time as a manager of expectations. I just wanted to clarify that at the April 19th workshop we will have the results of the reference case. We will have the input assumptions for the other cases but we won’t have results for those until the final work is done sometime along August.

CHAIR WEISENMILLER: Okay, thank you.

MR. KAVALEC: Good morning. I am Chris Kavalec from the Demand Analysis Office. I am going to talk about our general approach to forecasting and the economic assumptions going into the forecast.

But first I want to spend just a couple of minutes describing how our forecasting process works for those that haven’t been through it before. We do a forecast every two years for end use electricity and natural gas in conjunction with the IEPR report. In putting together that forecast we ask the utilities to provide certain information along with their own forecasts and we call this forms and instructions and the deadline to file that this year is April 15th. Today we are having, of course, a workshop on forecast assumptions. And our next workshop will be one where we present our preliminary forecast, that will be at the end of May. And public release of that preliminary forecast will be a couple weeks before that.

After we take into account and incorporate comments from stakeholders and internal comments with regard to the preliminary forecast we will develop a revised forecast, which we will release in August. And we will have another workshop. And if all goes well we will then have the forecast adopted later in the year.

Primary uses of our forecast: the CPUC’s long-term procurement process, Cal ISO transmission and capacity studies. In this IEPR cycle it's also going to be input into an infrastructure assessment that staff is going to be doing for this cycle.

We typically do forecasts which include what we call only committed efficiency. That means efficiency initiatives that are firm, have a specific program plan, they have been approved and they have been finalized. In the last IEPR cycle we also did what we called an incremental uncommitted forecast, where we estimated the incremental effects of additional efficiency initiatives that aren't quite as firm but still are reasonably likely to occur. This includes, for example, future federal standards and CPUC's Big Bold initiatives.

Speaking about workshops, we had a workshop on January 19th that dealt with California's economic future and we gathered together various experts from California and elsewhere to give their opinions and discuss what our future might look like. And I just wanted to give some thoughts on that workshop from a forecasting perspective, things that occurred to me that we should take into account moving forward and not just at the Energy Commission but other forecasters.

For example, at that workshop we talked about changing California demographics. We have a population that's both getting older in terms of the percentage of households with members above 55 years old, as well as younger, an increase in those 35 and under. And that has ramifications, for example, that may lead to reduced average household size, more condos, smaller homes. And that will have implications for our energy forecast.

Too often when we forecast, when we are forecasting energy demand, we take into account either income or output growth or employment but not both. There is a good reason for that in econometric models, these two variables are going to be highly correlated so it's going to be hard to get a good estimate for both in an econometric equation. But we see with this current recession sort of a bifurcation in terms of recovery. Income is recovering at a much faster rate than is employment. So it seems to me whenever possible we need to take into account both of these effects in our models. Otherwise, for example, with this recession if we are only taking into account income we could be overstating future energy demand and if we are only taking into account employment we could be understating it.

Going beyond our traditional measures of consumer purchasing power, we typically use per capita income. There are other measures that may be useful in energy modeling, for example, average consumer debt or average consumer wealth. Or we may want to try not just per capita income but variables that get at income distribution, like median income versus per capita income.

We talked about some other indicators of economic activity that may be useful. For example, Steve Cochran talked about an indicator Moody’s had put together called the business cycle indicator that we may want to take a look at in future energy modeling. And in the longer term if global warming impacts as we fear there will be some issues related to water demand in California. So in the longer term we are going to need to start incorporating water – in other words electricity load from water pumping – in a more sophisticated way to take into account potential future constraints.

Okay, on to the business at hand. I propose three economic-demographic scenarios for this preliminary forecast. One scenario would involve high energy demand growth. And this would include high economic-demographic growth, lower electricity and natural gas rates, lower efficiency impacts, and lower self-generation. We would also have a lower demand scenario which would have the opposite, low econ-demo growth and so on. And then we would have a mid or reference case which would have values for these variables in between the two.

In addition to that, for our incremental uncommitted efficiency analysis we will also have three scenarios, as we did in the analysis for the 2009 IEPR. And this will include a high, medium and a low case based on policy stringency, the level of dedication to policy, for example, how much future standards are ratcheted up in California. And it would include IOU programs beyond 2012, although that may change to 2013 if that becomes a bridge year for funding for the CPUC. Their next program cycle for efficiency programs may not start until 2014 or even 2015. So we will be including these uncommitted initiatives, future federal standards, Big Bold initiatives and so on.

The result of this when combined with our regular forecast will be what we call a managed forecast. And we are going to do this for the IOUs and this time in addition for LADWP and SMUD. And it makes sense to me that we would combine the high uncommitted efficiency scenario with the low demand case and vice versa, low uncommitted efficiency with the high demand case, and then the mid with the mid for a resulting three managed forecast scenarios.

Before I get more specific about defining this range I just wanted to give a brief description of the way we forecast at the commission. We have individual sector models for the various sectors. Residential and commercial is where we use full end use models. Also in the last IEPR cycle we developed econometric models for these sectors. And our goal here, what we are trying to do when we forecast, is look at things from both a low resolution point of view with an end use model and a higher resolution point of view, a more aggregate econometric model. And hopefully we gain insights from using both that we wouldn't get from just using one. And at some point if there is a big difference between the results from the two different types of models, there will be attempts to reconcile the two. And how that reconciliation is going to work, I don't know yet. This is the first time we're trying this two different model systems.

The industrial model, we have a sort of hybrid econometric end use model along with a pure econometric model we estimated in the last IEPR. An econometric model for the agricultural and water pumping sector. And trend models for the other smaller sectors, TCU (transportation, communications and utilities) and street lighting. And here is what the structure looks like in chart form. I couldn't fit in the TCU and street lighting, but pretend it's there on the right.

So the output from these models feeds into what we call our summary model, where results are aggregated and calibrated. Then that is fed into our peak demand model, where load shapes are applied to give us a peak forecast. And, boom, you have a wonderful forecast that nobody ever disputes.

(Laughter.)

Okay, in doing this forecast we use various economic-demographic variables listed here: personal income, employment, persons per household. At the industrial level we break it down into individual NAICS groupings, North American Industrial Classification System groupings. An example of a grouping is textile manufacturing or another is resource extraction. So we forecast at that level in the industrial sector.

So three scenarios involving econ-demo. We are creating three scenarios around these econ-demo variables, choosing from nine available scenarios from Moody’s and Global Insight. There are others that forecast for California but none of them give us the geographic disaggregation that we need or the number of years out for the forecast that we need. For example, UCLA forecasts for California but they only forecast out to 2012 currently and we need to forecast out to 2022.

Okay, so nine scenarios to choose from. The first six come from Moody’s, economy.com. They have their most likely case, they have a more optimistic case with a stronger rebound out of the recession, no further decline in housing prices. More pessimistic cases, a slower recovery. In S3 we go back into a recession, we don’t recover completely and go back into a downturn. Then there are two scenarios that reflect lower growth in the long-term, S4 and S5. And they have one that they call fiscal crisis, which means that we don't get the federal deficit under control, the dollar crashes, interest rates go way up, and so on, which is a drag on the economy.

From Global Insight we also have an optimistic scenario. We also have their base case, their most likely case; an optimistic scenario fueled by, among other things, an increase in housing starts; and a pessimistic case, where the financial sector remains in poor shape.

And here is what these scenarios look like. Here is a good example of a graph with too much information on it. But what I want to show here is the spread between the high and the low for these key econ-demo variables. So in the case of personal income the spread between the high and the low is nine percent. For employment it is six percent by 2022. And when we get to manufacturing here we see that there is a big difference in the feeling about our manufacturing future in California between Global Insight and Moody's. The top three lines there are all Global Insight, so they are much more optimistic about our manufacturing future than is Moody's.

And in the January 19th workshop we talked a lot about the impact of the downturn in construction. One of the main reasons why we have such a high unemployment rate is we've lost so many construction jobs. So in terms of that we also see that the two companies kind of diverge in their view. Again, all of Global Insight's three cases are well above the Moody's cases. So they are more optimistic about a return in construction employment. It almost looks like for Global Insight we are going to have another housing boom. And I asked them about it and they said, no, this is coming mainly from a resurgence in commercial development.

So among these nine we propose to use these three for our high, mid and low cases. I'm now wedded to these necessarily. It's just when you propose something specific you tend to get more reaction and comments. So for the high economic growth I am proposing to use the Global Insight optimistic case. For the mid-case, that would be the Moody's base or most likely case. And for the low economic growth I am proposing one of their pessimistic scenarios, S4, protracted slump in the long term.

And here is what these look like by themselves. First, for personal income and then for employment. What I am basically doing is choosing the scenarios that give us the biggest spread in the long run by the end of the forecast period. And that's what these three do. Our forecast is a long-term forecast, that's mainly what we are interested in. So I'm looking for differences by the end of the forecast period. Some of these other scenarios differ more in the short run but by the time you get to the end of the forecast period you are almost back to the base case. Although for manufacturing output you don't get a spread on the low side, although you get quite a large one on the high side.

Okay, so I'm also going to talk about our other assumptions, electricity prices and efficiency and so on. But I will stop here and ask for comments or questions with regard to our economic-demographic assumptions.

CHAIR WEISENMILLER: Thanks, Chris. I think probably my key question would be to try to get some feedback from the other forecasters, particularly the utilities, on what sort of assumptions they are using in terms of comparing your proposed scenarios to what they are looking at in their analysis. You don't have to do that now but if you do it now it would be great.

MR. EMMRICH: We are very comfortable using Global Insight. We have also used Moody's in the past specifically for some counties. But Global Insight seems to be recognized by all the utilities as a reliable forecasting tool. We are also proposing Global Insight in our current rate case. So that would be very nice if you had the reference case be based on Global Insight.

CHAIR WEISENMILLER: And how about the high and lows, do they seem too high or too low or just about right given the range?

MR. EMMRICH: They seem very reasonable.

CHAIR WEISENMILLER: Okay.

MR. EMMRICH: Very reasonable to me. I have not spent a lot of time looking at it but we will and we will provide comments on that.

CHAIR WEISENMILLER: Certainly more detailed comments later would be appreciated.

MR. EMMRICH: Thank you.

MR. ASLIN: Hello. Richard Aslin from Pacific Gas and Electric Company. So, Pacific Gas and Electric Company, we do plan on using for our forecast six of the Moody's analytic scenarios for how we are going to eventually come out of this recession, although I would agree with Chris that the Moody's analytic scenarios all tend to quickly revert back to the base case after two or three years, so you don't get that big of a spread at the end. But for our forecast, you know, in a lot of ways we are looking at the near term, that is very important to us. So we are looking at that spread.

I have to disagree with Herb a little bit. We are not that big of a fan of IHS Global Insights for their regional forecast. I think they tend to be a little bit out of touch with the California economy and that they tend to be focused more on the national and international economic modeling. But in terms of the spread on the three scenarios that Chris was proposing here, it seems like a reasonable spread. So that is my take on that.

CHAIR WEISENMILLER: Well, the other interesting thing is that this is the first year that Chris will have both end use and econometric models to look at.

MR. ASLIN: Yes, very much encouraged by that.

CHAIR WEISENMILLER: And I guess you are much more econometric and Herb is much more end use. So in terms of potential insights we might gather from looking at the two tools.

MR. ASLIN: Yes, I really want to complement Chris and his staff on taking the extra effort to produce both the econometric version of the models and the end use models. I think, you know, what we have discovered along the way in these last few IEPR rounds is that for the most part the stakeholders are all using econometric models and that the end use model tends to be sort of a black box. Because stakeholders don’t have that model for the most part.

CHAIR WEISENMILLER: Right.

MR. ASLIN: But we all have the econometric models. So when we look at the econometric model then we can have a really productive discussion about price elasticity, income elasticity and the underlying economics and how they impact the ultimate demand forecast.

CHAIR WEISENMILLER: Yes, my hypothesis would tend to be that the econometrics would work really well in the short term and the end use would capture much better the structural changes. It could be more evident with the longer term forecast. I think that's probably how PG&E was doing it, I'm going to say, 15 years ago.

MR. ASLIN: Yes, that's how you would expect it to turn out. But I think maybe the reality is more along the lines of there is so much uncertainty as you move forward in time that it's not really clear. One thing about the end use model is that it is more accounting and engineering based, so it's a little bit easier to understand how everything stacks up. It is definitely good for testing the impacts of various policies and programs.

CHAIR WEISENMILLER: Right. Yes, but anyway I think having the two certainly would provide a lot more interesting opportunities as we go through to understand the trade-offs.

MR. ASLIN: Yes.

MR. KAVALEC: Rick, you said you are going to do six scenarios. So does that mean you're still going to have one that is called the most likely or the base case out of the six?

MR. ASLIN: You're really putting me on the spot there. Moody's has one that they call the expected but I am not sure that ultimately we will be choosing that one.

MR. KAVALEC: Okay.

MR. ASLIN: We will let you know which one it is.

MR. KAVALEC: But there will be one out of the six that will be your base case?

MR. ASLIN: Yes, we will have a base case forecast.

MR. KAVALEC: All right. Okay.

VICE-CHAIR BOYD: I would just comment that I, too, agree with and like the approach that Chris has taken with the two models. And, Chris, the take-aways I came away with from the January 19th workshop – that to me was a very troubling workshop in a couple of different ways. The incredibly heavy dependence on housing and construction, I understand how it took us down but the reliance on that to bring us back is a little troubling to me in that everything else has to come back in order to drag that with it. Although your comment about asking afterwards about construction, it being commercial, does give it an interesting twist to that concern.

And the other interesting thing that you did note was the incredible disparity on California as a manufacturing base in the future. Of course, our friends at the Chamber and CMTA were aghast, alarmed and in violent disagreement with the consensus of all of the economists, it seemed to me, that we are moving away as a state from manufacturing, we are the innovators and beta testers but not the manufacturers of things. And that will have a big impact on our future if indeed that comes true. But geopolitics tends to trump everything these days so it's a little hard to deal with it.

Anyway, I remain confused but I'm feeling better in my confusion at the moment.

MR. KAVALEC: Well, I should say that in both cases, Moody's and Global Insight, what is driving the manufacturing is not what we would call traditional manufacturing but it's the high tech sector.

Any other questions?

CHAIR WEISENMILLER: Yes. Actually I think Herb had a comment.

MR. EMMRICH: I would just like to commend on end use models. We have been using end use models on the gas side. On the electric side San Diego has not used end use models. I think end use models are very good for long-term forecasts because they track the end users. One of the things that the commission could help us on is to move forward on the surveys. We have the RAS survey, we are kind of stuck on the commercial survey, and we need that information to feed the end use models.

So I don't know what can be done to move that forward. It is always about customer confidentiality that we as the utility are restricted to in giving up individual customer’s end use data and so on. But that would help us a lot if we get those surveys completed.

CHAIR WEISENMILLER: Chris, do you have a comment on that?

MR. KAVALEC: You’re saying getting data from surveys that have been done or continuing with future surveys?

MR. EMMRICH: Future surveys and the one that is not being done now. The way it is, you have a RAS for a two year period then you have a commercial for a two year period and then industrial. So it’s only every six years that we get updated data. And I think on the commercial and industrial side it’s very important to get new information.

MR. KAVALEC: Yes, and we agree. Although it is, as you mentioned, very time consuming and we are kind of – our resources are a little constrained these days. We are going to continue with surveys but I don’t know that they are going to be able to be done with any more frequency than they have in the past.

But another thing also is in future surveys – they’ve traditionally been done to feed end use models. But we sort of want to go beyond that and start looking at consumer behavior as well as just counting up widgets, you know, for households and for the commercial sector.

MR. EMMRICH: I agree with that. But I'm not talking about having more surveys. I would just like to see the surveys that are supposed to be done every two years actually get done. And we are stuck now for about three years on the latest one.

CHAIR WEISENMILLER: This may be something where I would encourage you and the staff and the other utilities to talk. There may be some way in a collaborative fashion that we can figure out a way to get it done, even given the fact that there are staff limits. Particularly given this year's forecasting cycle, that's going to be hard for Chris to find the resources but maybe to the extent you have some of the resources or contract – anyway, let's try to find some solutions to move forward on that.

MR. EMMRICH: I appreciate that.

MR. KAVALEC: And we have urged the CPUC to get involved and they seem amenable to more participation in the surveys.

MR. CHAUDHURY: My name is Sharim Chaudhury and I work for Southern California Edison Company. And with respect to the econ-demo assumption for our demand forecast for the upcoming IEPR, I would like to add that we also subscribe to Moody's and also Global Insight econ-demo price forecasts. We will be using most probably three scenarios, one as a base case and a high end and low. And we are still sort of in-house talking about which should be the base one and which should be high and low.

And I would like to complement Chris also for developing, in addition to the traditional end use model, the econometric model that will help us to figure out why the resultant forecasts are different compared to end use type model versus econometric model. And we had quite a bit of discussion in demand analysis working group at group meetings on that. And I complement Chris on that. Thank you.

CHAIR WEISENMILLER: In terms of Edison's experience on the Moody's, you know, on the basic, which of the services do you tend to find most reliable?

MR. CHAUDHURY: I think we favor sort of Moody's. And Global Insight also is good. Depending on the point in time, one forecast could be more precise than the other. But if you compare over a time series period I think it could be a toss-up, okay? At one point in time Moody's may do better but six months down the line it could be Global Insight doing a better forecast.

CHAIR WEISENMILLER: Okay.

MR. KAVALEC: Any questions online?

(No response.)

Okay, so then I will proceed with my second presentation here, the other assumptions that I propose to develop these scenarios.

As a reminder, in our high demand scenario that means lower rates, lower efficiency and lower self-generation. And the opposite in the low demand scenario. And our friends in the Electricity Office provided us some scenarios for natural gas rates, which Ruben talked about a little bit this morning. Some EIA scenarios. An older forecast for the California Gas Report and a forecast from Bentek. And from this information I created five scenarios and they are listed here from low to high.

The first one, it says “Bentek/Low Case”, it is sort of Bentek and then my adjustment to the Bentek forecast. I will explain that in a minute. And three EIA cases, what they call their High Shale Case, which means a lot more new wells opening up compared to their reference case. Then their reference case. And what they call their No Shale Case, no additional wells being opened up after 2010. And then just because I thought there should be a real high price scenario I developed this return to 2008 case where prices are the same as in scenario four through 2012 and then they creep back up to the relatively high 2008 rates by 2020.

And here is what they look like on a graph. You can see that most of them are bunched up there between four dollars and six dollars by 2022, except for the real high case. That lowest case there, Bentek Low, their forecast was lower than any of the EIA cases though 2012 but then went back up and was the same as the EIA reference case after that. So what I did was to take the reduction that Bentek predicts through 2012 and then hold the price at that level through 2022, that's the low case. And you will notice there isn't anything here from the California Gas Report. And that's because, number one, it's a little dated but, number two, percentage-wise the increase that they predicted is almost identical to the EIA No Shale Case. So I didn't put both of them in there.

Out of these five scenarios we propose to use these for the low, mid and high cases. For the low case, the Bentek Low Case, the one that goes down the lowest by 2012 and then stays flat after that. In total that means a ten percent reduction on average in natural gas rates between 2010 and 2022. Then in the mid rates I propose the EIA reference case, which is almost 25 percent higher in 2022 versus 2010. And then for the high rates, the EIA no further wells, No Shale Case, and that leaves rates around 35 percent higher in 2022 versus 2010. Although I could be persuaded to use the very highest case, the return to 2008 rates, because of the variability in natural gas rates we've seen in the past. Anyway, this is my proposal for you to comment on.

And here is what these look like by themselves. If we went with the real high case, as I mentioned, we would be up close to eight dollars by the end of the forecast period.

So now moving on to electricity rates, what we did was to create some scenarios with the Energy and Environmental Economics, or E3, greenhouse gas calculator. We used this to create what we thought were six plausible scenarios using the five natural gas price scenarios that I just mentioned as inputs. And I should say that as a demand person we are sort of at the limits of my expertise since this is really a supply model that deals with resource issues. But if folks have major problems with this model, with this methodology, I would like to hear about it. But to me the model at least, from what I could see, seems to be internally consistent and gives you plausible results for the scenarios that we ran.

So it allows the user to create scenarios using differing assumptions for efficiency, natural gas rates, renewables, combined heat and power, and demand response. Also electricity demand. What is in there in the current version of the E3 calculator is the 2007 IEPR forecast and I changed that to the 2009 IEPR forecast.

So using this tool, I created the following six scenarios and these vary. We're looking at these from low to high, three here and three on the next slide. These vary in the sense of lower to higher natural gas rates, current efficiency levels all the way up to the high CPUC goals for efficiency. Current levels of rooftop photovoltaic all the way up to the goal of 3000 megawatts by 2020 installed. Current levels of renewables up to the 33 percent RPS being met by 2020. All of these have impacts on prices. And in the two highest cases, S5 and S6, they assume a cap and trade system where the price of CO_2 is 30 dollars a ton.

And here is what the scenarios look like. The very highest case is the return to 2008 natural gas prices along with the more aggressive policies in terms of efficiency and demand response and so on along with this cap and trade system. So that gives you the highest.

So I propose – again, I'm not wedded to these but these seemed like reasonable scenarios for our forecast in terms of low, mid and high. For the lowest case that involves the current level of efficiency only, the lowest natural gas rates and so on. That yields one percent lower rate on average. By the way, what we've been talking about here so far is average statewide rates, an average over all the utilities in the state. So low case gives you basically flat rates in 2022 versus 2009. The mid case assumes the mid CPUC goals for efficiency, which is what they are currently using for their procurement, and the EIA reference natural gas rates. And that gives you a little bit less than 10 percent higher rates in 2022 versus 2009 on a statewide average. And in the high case we have the highest CPUC goals for efficiency and the second highest natural gas rates, almost 30 percent increase on a statewide average between 2009 and 2022.

And here's what these look like by themselves. You will notice in the S3 and S5 the mid and the low case. There is a decline between 2009 and 2012 and that's a function of the way the E3 calculator works. Its first forecast year is 2012. And then the less aggressive policy case is it actually predicts rate reductions in 2012 versus 2008. And I don't know how realistic that is, I would like to hear the utilities comment on that. But an alternative if we don't think this decline is realistic is just to straight line it from 2009 or 2010 to the end point in 2022.

Okay, as I said these rates we've been talking about have been statewide averages. The E3 calculator also predicts rate increases at the utility level for the five major utilities shown here. Here I'm showing one example for scenario S5 or our high scenario for rates. But this is representative of what happens in the calculator for the other scenarios, too. So costs for individual utilities or rate increases for individual utilities are based on assumptions about how they procure their electricity, where they are in terms of renewable percentages and so on. So in this case we see PG&E a little bit higher in percentage terms versus the state average, San Diego about the same as the state average, Edison and SMUD a little bit lower. And the most striking thing we see here is the very large increase for LADWP and that comes from the assumption of the cost of procurement for LA going up sharply with the expiration of their current contracts for procurement and because they are lower than the other utilities in terms of percentage renewables currently. So they have more to make up. So I would like to hear particularly from LADWP on what they think of this result.

Okay, in terms of efficiency, again I propose a high, mid and a low. High efficiency going for the low demand case and vice versa. For high efficiency savings I propose using the utility savings are reported. The mid efficiency case would be the same thing as we did in the 2009 IEPR. We took the utility reported savings and adjusted downwards using what we call a realization rate. And in a low case this would be applying the CPUC Energy Measurement and Verification results for 2006 through 2009. They found that realized savings were much lower than reported and lower than what we had in terms of an adjustment downward than what we had assumed in the 2009 IEPR forecast. So this would mean the largest adjustment to utility reported savings and that would be the low case.

And my guesstimate here is that the difference between the high and the low efficiency would be between 5,000 and 10,00 gigawatt hours in 2012.

For the uncommitted efficiency part, the incremental uncommitted efficiency, we need to rely on the work from the 2009 IEPR since there has not yet been a new goals study to work with for efficiency. We will do this for the three IOUs, as I mentioned, plus this time including LADWP and SMUD. And as you move through time sometimes what was previously considered uncommitted becomes committed. And in this case a 2010 Title 24 update that hadn’t been finalized at the time of the last IEPR was uncommitted and will not become committed. And the Huffman Bill for lighting, because it has been integrated into the Title 20 standards, goes from uncommitted to committed in this forecast. So all else equal we are going to have more committed savings and less uncommitted savings in our forecast.

For rooftop photovoltaic we’ve developed a predictive model for the residential sector and that will automatically give us three scenarios because the predictive model depends on average household income and average rates. And if those two things are varying in the scenarios then the results from the predictive model are going to vary. And for CHP, again we are sort of at the edge of my expertise in terms of what to assume for CHP going forward, meaning the amount of power consumed onsite rather than sold back to the grid. So I will rely on stakeholders here for comments. But also there is going to be a staff workshop on March 8th dealing with RPS and there should be discussion there about what to assume for additional CHP going forward. So I will be looking to that discussion as well.

And that concludes my second presentation. Any questions?

CHAIR WEISENMILLER: Chris, that was a good presentation. A couple of questions and suggestions. The first would be on the gas rate stuff. Check back with – I think probably Katy is here, but certainly Katy and the utilities on what they are seeing looking at the sort of futures approach for the near term, again, next five or six years. How similar or different would that be from your reference case? So to try to sync that part up.

I think in terms of looking at your electricity rate approach, I certainly like the idea of relying on E3. Again, I think in this era of limits it’s good if we can sort of be sharing, building off of what the other agencies are doing, making the appropriate adjustments as opposed to, say, developing our own model there. Certainly I think it looks like you have some degree of checking the assumptions that are in the LTP scoping motor as you’re constructing these. And, again, for those scenarios consistency is some virtue there, although I would point out that certainly Governor Brown’s calls for DGU much higher than within those documents and we need to consider his goals.

And I think in terms of the – certainly starting to look for hopefully a lot of interesting discussion on the electric grid scenarios. I would point out LADWP actually hit 20 percent this year. So their renewable performance – although certainly the metric is different, the way they calculate it in the IOUs – but at least nominally they are at 20 and certainly the IOUs are struggling, more struggling relative to that.

And I think on the self-generation side certainly one of the things to look at on CHP is – I think one of Commissioner Byron’s legacies was that ICF Report last year or within the last IEPR. So trying to figure out what that said and then what the QF Settlement Document says. Going forward on CHP, again, would be one way to try to make some sense out of what the future could look like there. But, again, certainly very interested in hearing from each of the utilities on these sets of assumptions. Who wants to go first?

MR. EMMRICH: I believe the scenarios outlines are very reasonable. Of course, we will take some time to study them.

CHAIR WEISENMILLER: Sure.

MR. EMMRICH: I did have a comment about the California Gas Report. I don’t know, which one were you using? Because we had the 2010 which was just published.

MR. KAVALEC: Right. Yes, that’s the one I was referring to. How old is the forecast in that?

MR. EMMRICH: That’s from last year.

MR. KAVALEC: Yes. So, as I said, it gave basically the same results as the EIA No Shale Case. So I didn’t include it in there.

MR. EMMRICH: Yes, gas prices have fallen a lot. But what you need to look at also is if you do have greenhouse gas legislation and you phase out coal plants you are going to have a big increase in gas demand. We have plenty of shale gas available so we have more supply but you also may have a lot more demand.

MR. KAVALEC: Right.

MR. EMMRICH: And the forecast we use in the California Gas Report reflected that.

As far as energy efficiency, you know, it’s always a contentious issue on how you calculate the ongoing and the naturally occurring. The utilities, of course, spend a lot of time and effort in order to promote energy efficiency, that’s sort of our life blood at this point. We don’t go market additional gas uses, we go out and market additional energy efficiency programs. And we want to make sure that there is a proper reflection of our efforts, which is certainly leading the country in that area.

MR. ASLIN: Richard Aslin again from Pacific Gas and Electric Company. I had a couple of comments. The first one was that, would it be possible to include some sort of climate change in the scenarios? Because I know in the last IEPR cycle we took quite a long look at that and I think that you developed some scenarios that did have climate change and I think that they actually did show a significant difference in the amount of demand, depending on what you assumed about climate change. So I would think that putting climate change in there would be –

MR. KAVALEC: The answer is yes, we just haven’t developed the scenarios to the point where I wanted to present them here.

MR. ASLIN: Okay, thank you.

And the other thing, I just want to make this observation on the electric rate increases. I believe the percentage changes you were showing were real percent change?

MR. KAVALEC: Yes.

MR. ASLIN: Right. So if we translate that into nominal changes they are quite a bit higher. So the one percent increase in real in the low scenario actually translates into a nominal increase of – what would you say, Chris, 25 percent? Or something? Inflation is about 2.5 percent on average.

MR. KAVALEC: Right.

MR. ASLIN: And then in the high case it's going to be approaching 50, 60 percent.

MR. KAVALEC: Or more, yeah.

CHAIR WEISENMILLER: As you do your forecast and look at the price effects it sounds like yours are much lower in terms of rate impacts?

MR. ASLIN: Right now I think embedded in our base case forecast would be similar to what Chris has in the low case. So we have real prices increasing by one percent.

CHAIR WEISENMILLER: So one of the questions – and, again, this is more for your initial reactions, but certainly in your written comments if you could sort of focus on the construction here and try to identify what is really making the big difference there out of all the various assumptions we have.

MR. ASLIN: Uh-huh.

CHAIR WEISENMILLER: It may well be gas but it could be more subtle than that.

MR. ASLIN: Yes. We definitely will plan on having some sort of written comments.

MR. TOTH: Hi. I'm Phil Toth with Southern California Edison. Chris, a very good presentation. I have some inquiries about page 15, small page 15, and it has to do with energy efficiency program scenarios. And just thinking through recent history, adjustments to EE have been made about some of the components within the total market growth goals, most recently in LTPP process where they are adjusting the Big Bold EE strategies. And in past conversations we’ve talked about whether we should include Big Bold in there or should we not.

And I see that you are focused on adjustment of the totals, such as you have utility reported savings versus the IEPR adjustment versus – in the IEPR adjustments you’re talking about the committed/uncommitted analysis that happened about this time last year?

MR. KAVALEC: Here I’m talking specifically about the committed part, the committed efficiency programs. In terms of the uncommitted, I believe what the CPUC ended up using for procurement it was the mid case with an adjustment for the Big Bold initiatives downward.

MR. TOTH: That’s my understanding.

MR. KAVALEC: And I think that’s what would become our mid case, using that same adjustment the CPUC made.

MR. TOTH: So if that would be your mid case – just really quickly looking through here – is there a proposal in here about a high and a low case regarding uncommitted?

MR. KAVALEC: Yes. It’s basically the same as we did last time, the policy driven high, mid and low, with the exception that I just mentioned.

MR. TOTH: Okay.

MR. KAVALEC: We have to rely on the same work because we don't have a new goals study yet.

MR. TOTH: Thank you, Chris.

CHAIR WEISENMILLER: I'm afraid to ask this, is there anyone here from LADWP?

(No response.)

Chris, why don't you reach out to them and again try to sync up.

MR. KAVALEC: I will.

CHAIR WEISENMILLER: I would certainly be happy to help do the connections. But, again, to make sure there aren't any big differences or surprises there.

MR. KAVALEC: Okay.

Any questions on the internet?

(No response.)

MR. MARTINEZ: Thank you for the presentation, Chris. And thank you for the opportunity to present comments. My name is Sierra Martinez and I'm here representing the Natural Resources Defense Council.

NRDC has over 124,000 members here in California and a strong interest in reducing the environmental impacts of our energy consumption. NRDC is concerned with how energy efficiency is accounted for in the demand forecast. We commend the CEC for setting up the demand analysis working group and commend the CEC staff for making themselves accessible in holding discussions on how energy efficiency is treated.

However, the demand forecast has significant shortcomings in determining where the energy savings are coming from. Previously the CEC produced representations of energy efficiency with about 50 percent of the energy efficiency being attributed to codes and standards and about 50 percent being attributed to utility programs. This is commensurate with how our neighbors in the Pacific Northwest estimate energy efficiency, it’s commensurate with how the PUC evaluated savings historically, and it was presented in the 2005 Energy Action Plan, too. It was also presented in the 2003 IEPR cycle.

However, in 2009 an alternate graph was produced which drastically reduced the amount of efficiency attributed to utility programs. It reduced it approximately 75 percent. This drastic reduction in attributing savings to utility programs is not commensurate with how other regions estimate efficiency. Furthermore, it undermines our ability to get the efficiency savings from utility programs going forward if the savings are represented as so small. The demand forecast is designed to produce forecasting results and therefore needs to incorporate the total amount of energy efficiency but is not designed well to determine where the savings are coming from.

Thus, NRDC recommends that the demand forecast use a single total estimate of energy savings for the purpose of demand forecasting. The total amount is what is necessary for forecasting purposes. NRDC also recommends that this year’s IEPR retract the graph from 2009 due to the forecast’s inaccurate depiction of attribution of savings to utility programs and because it was never intended to serve as documentation of attribution. Last, NRDC recommends that the CEC create a process specifically dedicated to accurately depicting California’s history on energy efficiency and the savings caused by various policy interventions. Thank you.

CHAIR WEISENMILLER: Thank you. I know this agency has made a major investment with the PUC for the last couple of years trying to deal with some of the attribution questions. And so I’m hoping NRDC has been a participant in that process. Obviously, as we go forward the attribution is very complicated. We tend to look at things particularly when they move from utility programs into the standards as at that point the attribution is more to the standards than to the utility programs. And I guess that has at least been one source of controversy.

But, again, I think we certainly would appreciate having staff and NRDC having a dialog on these issues and NRDC's participation, particularly in the quantification process. Chris, do you want to say anything else?

MR. KAVALEC: Yes, and there is a question about the total amount of efficiency savings and what we actually report as affecting the forecast. It's a little bit complicated because in some of our models, the econometric models, you have efficiency included in the result itself because you're using actual historical data that includes efficiency. So, in other words, when we report efficiency as affecting our forecast it doesn't necessarily include all the efficiency.

The other issue is that we had this discrepancy that Sierra was talking about in terms of reported efficiency because there was an analysis done years ago that reported simply all utility programs as savings. And a later graph that Sierra was talking about for 2009 showed the amount of efficiency that actually affected the forecast, which are two slightly different things. So anyway, we are working with the NRDC through the DA (ph) group to sort this out and we are going to attempt to report this in a much more accurate, meaningful, useful way in the next IEPR.

So anyway, we are aware of this issue and we are talking to the NRDC in the DA group meetings about this and we are trying to work out a solution.

MR. MARTINEZ: Yes, and we appreciate it very much, all the work that has been put into it. And in response to your question, Chair Weisenmiller, NRDC is present at the PUC in voicing our concerns over how energy efficiency is attributed. The big difference here is that the CEC does produce a historical graph of energy efficiency which is not commensurate with what the CPUC litigated historically in the 90s to determine evaluated savings. Thank you.

CHAIR WEISENMILLER: Okay, thank you.

If there is nothing else I guess we will break for lunch.

MS. KOROSEC: Let’s try to have everybody back here by 1:00. Thank you.

(Off the record at 11:45 a.m., to resume at 1:00 this same day.)

A F T E R N O O N S E S S I O N

1:05 P.M.

MS. KOROSEC: All right, we are going to go ahead and get started again. We will start with Malachi Weng-Gutierrez from the Fossil Fuels Office.

MR. WENG-GUTIERREZ: Good afternoon, Chairman. My name is Malachi Weng-Gutierrez and I work in the Fossil Fuels Office.

I'm going to be discussing our general approach to transportation energy analysis and the scenarios that we are going to be running in support of the 2011 IEPR. What we will be covering today is general purpose and uses of our analysis and I wanted to mention some of the statewide goals we will be doing comparisons to. We will be discussing the overall framework and approach that we will be taking for our modeling work, we will be discussing the specific models, and then discussing our proposed demand scenarios that we will be running, and then get into the specific price scenarios and cases that we will be incorporating into our demand scenarios. And we will end with discussion about policies and some of the infrastructure analyses that we are going to be producing in the next six months or so.

As many of the speakers this morning mentioned, the Energy Commission has some mandated responsibilities to produce forecasts and assessments of different energy uses in California and that is true for transportation energy as well. And so we at the Fuels and Transportation Division always have to do our share of forecasting and scenario development and assessments. So we hope that the product that we produce is valuable to the IEPR as well as other uses.

Here I have a couple of other areas that are demand scenario assessments and our price forecasts have supported. One of the big ones here at the Energy Commission, in addition to just general policy development, is the Alternative and Renewable Fuel and Vehicle Technology Program. Our forecasts certainly provided some input into one of the original allocation analyses that were performed for the investments that were made in the AB 118 work. In addition, we perform infrastructure analysis assessment using as the basis of that assessment our demand forecast. And we also will be looking at petroleum use reduction in comparison to what we are producing for our different scenario cases.

We also in the last IEPR cycle had a specific electricity demand forecast for transportation energy, which we provided to the Demand Analysis Office and they included in their overall statewide analysis of demand for electricity. And we intend on doing that again this time around as well.

Since our forecasts look at a wide variety of energies we include electricity and natural gas in our assessments, in our demand assessments, and we as a product of that inclusion get a number of things that are valuable for different policy analyses, one of which is the electric vehicle and plug-in hybrid electric vehicle population or the stock in the future. And we have used that in the past to compare against things like the ZEV mandate or other zero emission vehicle program goals and seeing whether or not we are compliant with that. It also gives us a general sense of the overall fleet fuel economy, given a changing mix of vehicles into the future. So we also have a mix of natural gas vehicles which are produced and then, of course, rail, different types of rail are produced as a product of that.

So this is a slightly different approach than we've had in the past, emphasizing certain statewide goals. And this is something that I think we are going to try to highlight a little bit more in our analysis coming up this IEPR cycle. And I think what I'm looking for here is perhaps a little bit of feedback about what goals we should be looking at, what are the metrics by which we should be looking at them. But the two that we are proposing to put forward and that we would like to kind of set forward as a basis of some of our comparisons are the petroleum demand reduction that was identified in AB 2076, which is a 15 percent reduction of on-road gasoline and diesel below the

2003 consumption level, achieving that reduction by 2020. And then the next goal would be the alternative fuel use, 26 percent alternative fuel use by 2022.

So just as a reference to show what we did in the past and compare it to those two goals, I put together this slide that shows our 2009 IEPR demand forecast and its comparison to the 2076 reduction goals, that 15 percent below 2003. So in this slide there are a few things going on. The brick red consumption on the left is actually the historic BOE numbers slightly adjusted by staff to account for, you know, credits and things like that. And then the green line and the purple line going forward represent our high and low RFS-adjusted demand numbers for the future. These are from our 2009 IEPR so they don’t necessarily obviously represent what we will have this time around and they have their own set of inputs that went into developing these demand numbers. So they will likely change. But, again, I wanted to illustrate the type of analysis that we will be performing, or comparisons that we will be performing for this IEPR round. The bright red line is the goal and it starts in 2020. That’s the goal that I calculated using some of our numbers. So the actual number would be dependent upon what you include in your 2003 consumption value. And that’s something we can spend a little more time discussing. But this is a pretty good approximation.

One correction, the bar charts which correspond to the axis on the right, which really is illustrating the volumetric difference between the goal and our forecast, in the legend it actually says “high to actual”, which is not true, it is not high to actual. It is actually the high to goal and the low to goal difference.

And, again, I just wanted to illustrate that the year that we come the closest to our goal is 2022 as far as the petroleum reduction and this is incorporating in the reductions due to RFS2 compliance. So in the 2009 IEPR we had kind of a second set of adjustment numbers that were due to RFS2 and those are the numbers that I’m using here.

And then next would be the alternative fuel goal. And this is just using all of the results from the 2009 IEPR for the high and low petroleum demand numbers, pulling out all of the alternative fuels including the blended ethanol volumes from the gasoline, creating a BTU content calculation and just going with a straight percentage and representing it here through the forecast period. As mentioned in the previous slide, the goal is 26 percent by 2020. And I haven’t illustrated that here but it’s a little bit above the 25 percent mark here and we are obviously well below, given our 2009 IEPR results. So that might well change with the addition of other policies that we are analyzing in this IEPR round as well as our different price tracks, which we will be discussing. They will be different from the last IEPR cycle but I wanted to illustrate part of the comparisons that we will be doing for our IEPR this time around. If there are other goals or things that are important that would be well represented or what you would like to be represented or analyzed by staff, we would appreciate direction to what those goals would be.

So the next is a data flow chart. It basically represents our modeling work. It includes the inputs at the top of the chart showing basically all the different types of inputs – there are others as well but this is a representation of some of the major ones – and where all of those inputs feed into. The blue boxes here represent the simulation models, the models we have, econometric models that we have and the different sectors that are represented in our models. The gray box to the right for off-road is not something we have internalized in our models but we do calculate that in a separate cut of calculation. The blue dotted box there, Congestion & Feedback, that’s something that we had a little bit of feedback between the models in 2009. This time around we have expanded that capability and so certainly the congestion component is something new. It will be interesting to see how that congestion plays a role in people’s choices, both in mode and in vehicle stock. So we are eager to see how that new component or module affects the overall demand. Down below the green box is obviously the result of our analysis, which would be the overall California transportation energy fuel demand. And then to the right in red are the supply side implications of our demand forecast as well as the supply/demand balance which we use at the base year to gauge how close we are to actual. So we use that as kind of a calibration point. And that's why there is a two-way arrow down at the bottom between the green and the red there.

In this IEPR cycle we will be looking at these fuels specifically. They are very similar to the ones we looked at last time: gasoline, diesel, electricity, E85, jet fuel, natural gas and then biomass-based diesels. Many of these are outputs of the models themselves and then some may be – the volumes that we project in our demand forecast might be affected by our post-processing or our policy analysis. One of the things I wanted to mention that is not here and just highlight it as absent is hydrogen. That is not something we have on this list and we are not intending on projecting a forecast of that demand.

And this next slide is not the quite the full list of all inputs but this is high level inputs that we use in our models as well as the sources for those inputs. Obviously, we will be talking this afternoon a little bit more specifically about the fuel prices that we will be using. And we will go into detail about what sources we are using for those. In the base year we use BOE and staff calculations as well as EIA to determine what our base number for consumption is that we should be using in our base year.

Econ-demo data and projections are going to be pretty much consistent. I think our approach will be consistent with what Chris will be using in the Demand Analysis Office. The other couple of ones I wanted to highlight here are the vehicle registration data. It is a great source of information. We have that as one of our internal program area of responsibilities, managing that and getting that information from DMV. So we have a great source of information there and we use it all the time. And it certainly sets the foundation for our base year vehicle stock number and plays a big role in our analyses.

One of the other big inputs that is kind of pivotal to or analysis is the projections of vehicle attributes. And this is done by class. This is a product of consultant work, ICF. We have had them performing these vehicle attributes, these projections for us for the past few IEPR cycles, perhaps all the IEPR cycles really. And it really is an important input into our models. It determines what the marginal cost of any specific technology is against any other technology. It gives us all of our efficiency numbers, it gives us many of the inputs to the vehicles and the types of vehicles. And that influences not only the final consumption, not only the number of miles which are traveled, but also what vehicles are acquired in California in the future. And that's done through the vehicle choice component of our models.

And then I just wanted to follow that with the vehicle choice of preferences. We will be using the 2009 household vehicle survey results. There is not an updated one. That is a survey that the Energy Commission funds and we go out to obtain data and then use it to define the preferences in our vehicle choice model. So for the 2011 IEPR we will be using the same values that we had in 2009. We are in the process of going forward with another survey and are intentionally working with CalTrans to develop even a more rigorous and wide-ranging survey. So we should be getting a whole slew of information from that survey.

So the demand scenarios that we are proposing for the 2011 IEPR are these. Basically, a high and a low petroleum demand. The emphasis here is on petroleum demand. In the past we have kind of emphasized that as our high and low categories. Of course, embedded in that we look at the alternative fuels and how they compete in the marketplace against the petroleum fuels. And that is represented in the transportation fuel prices, the two cases that we have. So in the situation where we have a high petroleum demand, obviously we are going to be seeing a low petroleum fuel price and a high natural gas and electricity price, which would cause the petroleum demand number to be the highest that it potentially could be.

In the low demand case we have high petroleum prices and correspondingly low electricity prices. And again that would ideally give us a fairly decent market penetration of natural gas and electricity into the marketplace. So we are looking at both the magnitude of the petroleum demand as well as the range of natural gas and electricity market penetrations. Along with the fuel price cases that we will be running, we will have obviously the economic growth rates that were spoken about this morning by Chris. Again, we will be looking at probably their high and their low case and then using those as the basis of our economic growth components. And it says “Economic Growth” but really it’s including all of the econ-demo values, employment, income, all of those things are included in that.

So I touched on it earlier. But explicitly the methodology we are going to use is a two step approach. The initial modeling of demand is going to come as an output from our models and that’s a product of all of our modeling and all the inputs that go into the model. And then after that there is some post-processing work that occurs. It occurs for a couple of different reasons. Some of it is policy analysis and some of it is actually to quantify demand in certain areas. And I will go into detail in a few slides.

There have been a couple of changes. These are just the ones that I wanted to highlight today in the methodology that we’re using for our modeling. The big one is that we have a different aviation model than we did in 2009, it’s pretty much entirely different, zonal in nature, it’s going to have some interaction with the mode choices and those sorts of things. So it is a little bit more integrated with the existing models and it does have a different structure than it had in the last IEPR. Also vehicle miles traveled, or VMT, is going to be calculated in a different way than in the past. In the past it was calculated in the vehicle preference component of our models and now it is actually going to be part of a simplified travel model. It will be used to determine how many miles are traveled by personal vehicle, how many miles are traveled by public transit, that sort of thing. So those are kind of the two key differences from this IEPR cycle and last IEPR cycle.

We will also be updating our transit information with Energy Commission surveys of transit agencies. We collect information from transit agencies to feed into our models. And we are looking at hopefully expanding the number of transit agencies represented there and getting a better set of data as well. Lastly, I just wanted to mention we will be using a different set of data than we did in the past for freight, with the Freight Analysis Framework data that is a little more updated than in the last IEPR cycle. We used a different data source and hopefully that will better represent and expand the analysis that we have for freight activity.

In the document that we have that supported the workshop we have a slew of policies that we've actually included that we wanted to discuss and that we thought were important and we wanted to consider. What we wanted to highlight rather than those that we were interested in are those that we are not interested in – let me rephrase that. Not that we are not interested in them but that we won't be including in our forecast or in our work primarily because how we would get those into our models would be difficult. And that's primarily the reason. In some instances the definition of how those measures or metrics would come to pass are not well defined. And so there is a bit of ambiguity as to how we would define them in our modeling efforts.

In some instances the resolution or impact of the policies are regional in nature and that's not something we can represent in our model as well. So in the case of ship electrification, the work that was done on that was done numerous years ago. Things have changed in the marketplace. The estimates that were used as the basis of those, that reduction, may not necessarily be true today. So those things have changed as well as the regional impacts would obviously be at certain ports that you would see these impacts. You know, we might be able to do some type of analysis after the fact but incorporating those into our model, it's not possible since our model really doesn't have that capability to look at, like, ship electrification.

So that being said, I think the National Ambient Air Quality Standard is something that Gordon is probably going to touch on as well. But, you know, these are things that we can look at outside of the model but incorporating it into the model is not really going to be easy to do in the short term.

And then for my last slide I just wanted to again discuss the post-processing activities and the policies that we will be looking at. Primarily, the models that we have right now don't internally estimate the fraction of demand which is accorded to, say, the electricity component of PHEV consumption. So we have to do that outside of the model. So what is produced as part of the model is the overall transportation energy associated with that vehicle class.

And then we have to calculate afterwards the fraction which is electricity and the fraction which is not electricity. So those are the types of things, the fuel selection component of these, those are handled outside of the model as a post-processing activity.

Similarly, off-road is not – we don’t have a model that represents that sector so we do that outside of the set of models that we use. And so it will just be something that we’ve developed outside. We’ve done that in the past and we will be doing that again, just to represent that sector in our demand numbers.

And then finally, certainly the policies, RFS2 policy and the LCFS, are pretty significant. We are going to spend some time on that. And I think Gordon is going to discuss those in his talks. But those are post-processing activities and would not necessarily be included directly in our forecasting model work. Although staff has talked about how we might try and do some of that, at this point the approach we’re going to take is that will be purely post-processing activity.

And with that if you have any questions I would be happy to answer them.

MR. OLSON: Thanks, Malachi. A couple of comments first on the 15 percent petroleum reduction. That reflects the Pavley and the CAFE standard impact? And can you show that in your graphic somehow, that contribution?

MR. WENG-GUTIERREZ: It would be difficult to show. It does include it because the initial set of vehicle attributes we have in the model represent those offerings which could include those overall policies. So in the case of CAFE standards, the consultant who is providing us with vehicle attributes has to consider both the price of the fuels in the marketplace as well as the policies that are influencing what OEMs offer in the marketplace. So I think what we are intending on getting on from him are those, the only-with policy case. So only with Pavley, only with CAFE. Now, we have yet to obviously – we have some flexibility and I think we are going to be discussing with that consultant about how we might separate those. I don't even know if it's possible for him to do that. You know, he's basing his information on contacts in the industry as well as things like that. So he might have to use his professional judgment to pull out those policies and what would happen, you know, maybe on a technology basis.

MR. OLSON: This has come up in other forums in terms of, what's the impact of Pavley versus the six percent drop in consumption from maybe economic downturn.

MR. WENG-GUTIERREZ: Sure.

MR. OLSON: Is there some way to do more refined attribution, if that's possible?

MR. WENG-GUTIERREZ: Well, and again it’s something that has been noted to us already. We’re looking into how we might approach that. So as of right now we can’t do that but we may come up with a solution that will allow us to do that.

MR. OLSON: Another comment on the 2022 twenty-six percent alternative fuel use.

MR. WENG-GUTIERREZ: Sure.

MR. OLSON: I think that reflects both on-road and off-road, which is different from the original 2076 twenty percent by 2020, which was only on-road. So you might want to check that just to make sure we’re reflecting that it’s both on-road and off-road for the 26 percent.

MR. WENG-GUTIERREZ: Okay, certainly. The representation that I had there for the 2009 IEPR did include the off-road values.

MR. OLSON: Very good.

One other comment about – and it goes to your report. I don’t know if this is premature to talk about this point.

MR. WENG-GUTIERREZ: No, not at all.

MR. OLSON: It’s on page 27 in the report, referring to how electricity consumption is captured for electric vehicles. You have a reference to – you’re using utility rate schedule tariffs that are additive in nature, meaning household use increases.

MR. WENG-GUTIERREZ: Yes.

MR. OLSON: I think that is changing and I'd like to hear feedback from the utilities, if not today at some point in this process, that states what their policy is, if they have changed to different rate structures. So what we hear in another forum, the PEV Collaborative Forum, is that those rates are separate meters or somehow counted separately and they are not triggering Tier 2 and Tier 3 pricing.

MR. WENG-GUTIERREZ: Sure. And I will get into more detail when I present the actual electricity prices for transportation use and the methodology that I used. They are not all – it is a marginal analysis but I didn't restrict in only to single metered rates. So I will discuss the dual versus single meter rate distinction.

MR. OLSON: And just one other comment on your methodology and how you address the supply side of this, the data and the inputs on supply. I think it would be really good to get some additional input from some of the alternative fuel industry people. Some of them have their own associations like the – well, the PEV Collaborative is a 35 member group, it includes utilities, automakers. That's a good data source for lots of different things, cost of vehicles, market penetration types of things. Same thing on the Natural Gas Vehicle Coalition. Industrial gas companies that we are funding for these hydrogen fueling stations will give us some more insights on hydrogen pricing. And Western Propane Research Council on propane.

In essence I think it's worth – you're doing a long-term forecast and we've got an infant industry that's using a slightly different way of pricing fuel. It tends to be long-term fleet contracts that are lower than retail prices. And it might be worth having that on the record, that as this industry kind of matures there is a near term difference in how fuel pricing occurs, knowing that at some point it probably goes to some kind of retail.

MR. WENG-GUTIERREZ: Sure. Yes, exactly. And I think I'm going to touch on that with the electricity rates that I will mention. But if there are – I mean, it sounds like you made some good suggestions about where to get some additional data and some things that we can consider as either ground truthing or inputs into estimating whether or not our price cases are reasonable. So I think that's a good suggestion and we will look into that.

Are there any questions from the room before we go on?

MR. BAMBERG: Les Bamberg from Sempra LNG. Kind of as you work forward on your demand outlook on natural gas I wondered if it would be possible to differentiate between

CNG and LNG since those have kind of very different infrastructure and supply issues.

MR. WENG-GUTIERREZ: Sure. And that’s something that we as staff kind of discussed as well. I have lumped them kind of together as natural gas here. That’s great feedback. I think we are looking at how we might, you know, separate them and how we would have them modeled, how we would allow them to expand out of different niche markets and that sort of thing. But it’s something that we have considered and talked about. So thank you for the feedback. We will look at it.

MR. BAMBERG: And kind of a second question as you look forward at demand on natural gas and electricity will you be able to offer any kind of commentary? Because, you know, the growth in demand may be more driven by things other than price. Will you be able to kind of identify those issues and where policies may be necessary to kind of help those things along?

MR. WENG-GUTIERREZ: Right. And I guess I’m kind of jumping ahead to our next step slide. But we are going to be having an infrastructure workshop in May and we are hoping to touch on all of those types of topics. And certainly infrastructure is a big component, certainly with the alternative fuels entering the market, what is the infrastructure going to be? The Energy Commission as a whole, AB 118, funds a lot of those infrastructure things. What are the results of our investments? How is that going to change the picture in the future? All of that really we are going to be starting to take into consideration as we move to the next workshop.

MR. BAMBERG: Thank you very much.

MR. WENG-GUTIERREZ: Of course. Any other questions from the room?

(No response.)

If not, then we have a WebEx question.

(No audio available – written question from Gina Grey of Western States Petroleum Association handed to Mr. Weng-Gutierrez.)

I’m just reading the question here.

Okay, well, as with previous IEPRs I think the difficulty and the challenge of including hydrogen vehicles is really the uncertainties associated with their costs and the attributes of those vehicles. So, you know, we can check again and see how comfortable we are with projections of vehicle attributes of that technology. But my thought is that, again, it’s still early in the process for defining what vehicles will come to market at what price. We will be including in our work projections of hydrogen fueling prices. But as far as the demand side analysis, it may be limited by the input data that we have. Maybe it’s something we could include but we would have to get a better picture about what those input values would be.

MR. OLSON: Malachi, let me also add that Energy Commission and Air Board are continuing to do surveys of automakers to help us define where those sales are going to occur and the demand, physical location. And it's a factor where the fueling stations are placed.

MR. WENG-GUTIERREZ: And certainly there have been introductions of hydrogen vehicles. Today it's just that long term and what are the attributes of those vehicles and what niche markets are they coming into and can we really define all of that in the context of our forecast period over the next 20 years with a degree of certainty or plausibility that we feel comfortable with?

So if there are any other questions.

(No response.)

MR. EGGERS: Good afternoon, Chairman. My name is Ryan Eggers and I will be presenting staff's proposed crude oil price cases for the upcoming 2011 IEPR along with our transportation fuel price cases.

To start off, my presentation intends to cover the current and historic trends in crude oil prices plus. I will then move into covering our proposed crude oil price cases for the upcoming 2011 IEPR. And I will finish off talking about our transportation fuel price methodology and price cases.

One of the reasons why we pay so much attention to prices is that they directly impact how much we spend for transportation fuels here in California and in the US as a whole. Shown here are real per capita gasoline expenditures as a percentage of income, which is denoted by the green bars on this particular chart. The red line shows you what the average of that has been over this particular time period, along with US real gasoline prices.

From 1983 to 1998 expenditures as a percentage of income have been falling from just above 3.5 percent all the way down to 1.6 percent. Most of this decline was caused by rising per capita income during this time period. From 1998 to 2002 expenditures as a percentage of income remained fairly steady, only once going above two percent. Then when gasoline prices began to rise from 2002 to 2008 expenditures also increased as a percentage of income, all the way up to 3.1 percent in 2008. When gasoline prices for the US fell in 2009, expenditures as a percentage of income also fell down to 2.25 percent.

Since most of the transportation fuels here in California are mostly tied to crude oil prices currently, here are some of the factors that affect crude oil prices. The big one being, of course, the supply and demand fundamentals on the world market for crude oil prices. Most of these other factors play into that dynamic. All I'm saying here is when supply outpaces demand for crude oil prices tend to be low, whereas when demand picks up like, say, developing economies such as China, which recently increased its imports of crude oil 42 percent, prices tend to pick up as well.

Resource nationalism has also played a role. Increased nationalization of oil production has had a restricting supply effect on average. These countries also tend to use their revenue from this nationalization in order to fund government programs, which also gives them an incentive to keep prices high. Rising oil production costs have played a role along with economic growth. During good economic times higher price points seem to be able to be supported and in worsening economic times lower prices seem to be dominant.

Dollar valuation fluctuations have also impacted price. This is the effect of the purchasing power of the US currency on the world market. Increased speculation is also a big factor, along with probably the most topical of all these factors, which is political unrest, especially in the Middle East. Currently in 2009 the Middle East produced roughly 28 percent of all world production and any sort of unrest here tends to disrupt supply and put upward pressure on prices.

To show just how supply and demand affect crude oil prices I have prepared the following chart. On this chart in green is Refiner Acquisition Cost of crude oil and the bars on this particular chart show the difference between world oil consumption and production in any given month along the chart’s bottom axis. What we see here is red bars which indicate consumption outpacing production in a given month. It puts an upward pressure on prices. The black bars correspond to downward trends in crude oil prices as the world market becomes more saturated with supply. Some of the best examples of where long-run consumption outpacing production has led to higher prices can be seen by the arrows that I have put on this chart, that is, from January 1999 to January 2000, then from January 2002 to July 2003 and finally in the recent price spike which occurred from January 2007 all the way up into July of 2008.

For the most part these supply and demand fundamentals explain most of the price changes on this particular chart with one notable exception, which occurred from January 2003 all the way into January 2006. One possible explanation for this rise in price is the dollar value on the world market. Shown here by the blue line is the dollar per euro exchange rate. As this line increases the dollar becomes weaker, thus putting on upward pressure on prices. I would also like to point out that during the most recent price spike we had both consumption outpacing production along with the weakening dollar, which is one possible explanation of why prices increased so dramatically during that time period.

Seeing how some of these factors can influence crude oil prices leaves some challenges for staff in order to make California transportation fuel prices. First, crude oil prices have proven to be very volatile and hard to predict. That being said, if we would get a handle on all the different factors, some of which we presented today, we could put them into an actual integrated world energy market. But unfortunately we do not have one in order to do that. IN the case of alternative and renewable fuels, there is often very limited data as these fuels are in their infancy. So developing some sort of relationship among the fuels is difficult at best.

Staff's solution to some of these problems is basically to use somebody else's forecast, specifically either from the EIA, IEA or some other agency. Staff then uses Imported Refiner Acquisition Cost, which is a sales-weighted average of crude oil for refiners, and then creates a relationship to other state fuels in order to give us some kind of pegging system in order to project these fuels into the future. Staff has also endeavored to consult with other offices within the Energy Commission on E85, natural gas, hydrogen as well as our electric rates for EVs and plug-in hybrids. Of course, staff would like to solicit any outside advice from workshop participants on any of our price cases in order to better refine them for the 2011 IEPR.

To start off, one of the reasons why we use Refiner Acquisition Cost of crude oil is because there are many different types of crude oil, all with their own prices. What we do know is that these prices often differ on the quality of the oil with light sweet oils often demanding a premium relative to heavier sourer crudes. Also supply and demand sometimes factors into this with supply constraints sometimes making these price relationships differentiate. A good example is the recent separation of the Brent and WTI that has occurred within the last week. But what we do know is that for the most part, as shown on this chart here, crude oil prices tend to move together on an aggregate level.

Refiner Acquisition Cost averages all of these for inputs to refineries here in the United States and kind of gives us an average of what crude oil was being paid for by the refineries. At the beginning of any sort of forecasting endeavor usually forecasters look at past behavior in order to project what the future is going to hold. Shown here is Refiner Acquisition Cost in historical terms, denoted by the two purple lines on this particular chart, the solid line being the inflation-adjusted prices with the dotted line being the nominal or posted price of crude oil in this time period. What we see here is that for the most part from 1968 to 2010 crude oil has been fairly stable with, of course, to obvious and very big price departures from that stability level. These in the past have been created through supply shocks. Also shown on this chart are our proposed crude oil price cases. Again solid lines represent inflation-adjusted dollars for these particular price projections.

One of the main take-aways of this particular chart is that for the most part crude oil has been steady except for price shocks and is seen into our price projections into the future. Also whenever the price of oil seems to rise to drastic amounts this has also historically stimulated more production of crude oil, which has had a downward pressure on prices and has eventually pushed it down into a more steady level. That being said, even though our real cost of crude oil, like, say in the high is only approaching close to $140 in inflation-adjusted dollars, when adding the EIA's inflation projections the actual posted price in 2030 is going to be closer to about $200 in our high case and closer to about $120 in our low case.

Staff also looked at our past price projections and historical values of that time frame, shown here by the red line, which is our 2009 IEPR high price case and the purple line is our low case. The green dotted line in this particular chart is the actual average monthly imported Refiner Acquisition Cost and how it performed during this time period. For the purposes of this chart alone staff has converted our yearly price cases into a monthly form. And as you can see for the most part Refiner Acquisition Cost stayed within the band, starting at the low end at the beginning of 2009 and then rising to the high end of our band in early 2010, then as 2010 progressed Refiner Acquisition Cost dipped back down to within the band.

When you average these out into a yearly form you get two points that fall within our price band. Staff also looked at short-term energy outlook price projections by the EIA along with NYMEX future curves, which can be seen on the right-hand side. At the time when these price bands were developed the EIA was predicting a quick jump in Refiner Acquisition Cost and then it steadies off within the next two time periods. The light blue line on this particular chart shows our new recommended low price case for the upcoming 2011 IEPR. Again, as you can see, the EIA’s short-term energy price projection falls right into the middle of that.

When looking at the futures we see a pretty steep contango in the early years of the NYMEX futures with a backwardation towards the longer time periods out into the five year range. In January when these price bands were being developed, our reading of the NYMEX futures was that over the long haul prices were going to be fairly steady throughout the first five years of our price projections.

Staff also looked at long-term forecast for crude oil by the other leading agencies in this particular field. Again the red line is our recommended 2011 IEPR crude oil price case, the lower or light blue line is the IHS Global Insight forecast, which we are recommending for the low. Other forecasts by the EIA, IEA and Deutsche Bank fall roughly within the middle of our price band, starting at the lower end in earlier years before moving towards the top of our band in the 2025 to 2030 region.

At this time I would also like to point out that the IHS Global Insight price projection that we are using in our low case this time around – or we are proposing to use this time around – is actually a WTI price projection not a Refiner Acquisition Cost price projection. Traditionally, WTI is cost around three to ten dollars more than the Refiner Acquisition Cost price. Staff did not adjust this line any lower because we felt it was already sufficiently low for our purposes.

Moving on to our price projection methodology for gasoline and diesel, our price methodology is fairly simple.

Basically, we use these Refiner Acquisition Cost price projections, convert them into a cents per gallon number, then we establish a Refiner Acquisition Cost to retail pretax price margins for both high and low cases, we then add the appropriate California and federal tax structure to these prices. I would like to point out that the tax structures we used this time are the new gas tax swap and diesel tax swap that the Board of Equalization has recently posted. In the case of gasoline these tax changes occurred July 1, 2010 and the diesel tax swap tax structure will change July 1, 2011.

We also made some assumptions in creating these price cases, the first being that in real terms all fuel margins for all the fuels are held constant within the projection period. Thus, when putting in inflation, which tends to be on the positive end, these margins are actually likely to grow in nominal terms. Also all taxes and fees are held constant in real terms. Again that means in nominal terms they will be rising. Staff has also assumed that all fuel formulations will remain constant into the projection period, meaning these prices do not reflect a transformation to, say, an E15 blend for gasoline. We have also incorporated no greenhouse gas reduction regulations beyond the Pavley rules. However, we would like to solicit any input on, say, policies such as the low carbon fuel standard and AB32 and how they are likely to affect prices. Currently, we still have not been able to quantify an adder to prices in order to account for these regulations.

Looking at gasoline and diesel Refiner Acquisition Cost to retail price margins, basically from 2000 to 2010 we have seen a fairly constant margin through most of that time period. Normally these margins are also very, very similar. They have ranged anywhere from 60 to 90 cents along this time period. There have been a couple of notable exceptions, one being 2003 and then in 2008. One of the possible explanations of why the gasoline margin was much higher in 2003 than diesel was that was the phase-out year of MTBE and us moving to an ethanol fuel. In 2008 analysis of the reason why diesel has kind of separated from gasoline in that year seems to be due to the seasonality nature of diesel prices. In the June and July time period crude oil prices spiked and diesel prices spiked as well. The seasonality plays into that in that there was some increased demand in diesel and it seemed to have helped increase diesel prices relative to gasoline prices during that time period.

These are our proposed crude to retail margins that we are proposing to use for the upcoming 2011 IEPR with regards to gasoline and diesel. In the high case we are intending to use a 79.9 crude to retail margin for gasoline and a 83.9 retail margin for diesel. In the low case the crude to retail margin would be 6.4 cents and 76.3 cents. Also, as I mentioned before, there have been some changes in the gasoline tax structure here in California. Our state excise tax has risen from 18 cents to 35.3 cents. In the case of diesel that 18 cent excise tax has been lowered to 13.6 cents. Also sales tax on these two different fuels has changed as well. In the case of gasoline it has fallen from 8.25 percent to 3.25 percent. In the case of diesel it has risen from 8.25 percent to 10 percent.

Using the price projection methodology here are the following results in real 2010 cents. In the high case gasoline starts at $3.76 a gallon in 2011 and diesel starts at $3.72 in 2011 in the high case. They then move to $4.28 and $4.37, respectively, by 2015. Then by 2030 the price of gasoline would be $4.70 and the price of diesel would be $4.82 in the high case. In the low case gasoline prices start at $3.24 for 2011 and diesel starts at $3.27 in 2011. By 2015 these prices move to $3.39 and $3.43, respectively. Then by the end in 2030 prices fall to $3.20 and $3.22, respectively. Values for this chart can be found on page 19, Table 4 of staff's accompanying document for this workshop.

That being said, these are also likely not to be the prices consumers experience at the pump in 2030. Instead, when adjusting for inflation using the same EIA 2011 annual energy outlook reference forecast for inflation, in 2030 the price of gasoline would be closer to $6.70 a gallon and $6.94 for diesel in the high case. In the low case, gasoline in 2030 would be $4.60 a gallon and diesel would be $4.63 a gallon.

Moving on to railroad diesel and jet fuel prices, in our railroad diesel price cases a crude to wholesale diesel margin of 61 cents and 51.6 cents were used for the high and low, respectively. Sales tax was then added in the case of railroad diesel in order to bring it up to its final retail price. In the case of jet fuel a crude oil to jet fuel price margin of 61 cents per gallon was used in the high case and a 36 cent per gallon in the low case. No taxes are added because these prices are intended to represent the price that a common carrier airline would pay for jet fuel and they are not subject to taxes.

Using this methodology this chart shows the resulting prices from that methodology. In 2011 the price of railroad diesel would be $3.07 in the high case and $2.62 a gallon in the low case. By 2020 railroad diesel prices would be $3.80 and $2.69 a gallon. Finally, by 2030 the price of railroad diesel in the high case would be $4.15 and $2.57 in the low case. Of course, these are all inflation-adjusted 2010 dollar projections here. In the case of jet fuel prices begin at $2.81 a gallon in the high case and $2.26 in the low case. By 2020 jet fuel is $3.49 in the high case and $2.33 in the low case. Finally, by 2030 jet fuel is $3.81 in the high case and $2.22 in the low case. Values for this chart can be found on page 22, Table 5 of staff’s accompanying document for this workshop.

Moving on to E85, B5 and propane price projection methodology, in the case of E85 we have pegged the price E85 to both our high and low gasoline price. The price is then adjusted by dividing by 1.37 to price E85 on a similar BTU content basis as gasoline. In the case of B5, which is a perfect substitute for diesel for most diesel vehicles, we have chosen to price it at the same price as diesel. Finally, for propane we use the high and low Refiner Acquisition Cost forecast and then multiply it by 84 percent in the high case and 73 percent in the low case and then add a wholesale to retail margin of 58 cents to bring it to its pretax price. Excise taxes of 24.4 cents are then added and a sales tax of 8.25 percent is then added onto the final retail price.

Shown here are our gasoline price cases and E85 price cases. As you can see, they have roughly the same general shape with E85 prices being lower because it is being divided by roughly 30 percent just for BTU content. The green lines on this particular chart show the E85 price cases. And in this particular diagram E85 prices begin at $2.68 in the high case and $2.37 in the low case in 2011. Then by 2015 they move to $3.12 in the high case and $248 in the low case. By 2030 E85 is $3.43 a gallon in the high case and $2.33 in the low case.

This particular chart shows our proposed B5 price and propane price cases. B5 is the two purple lines, the low case being the dotted line and the high case being the solid line. Propane is shown here as the red line, the high case is the solid line and the low case is the dotted line. In the high price case B5 starts at $3.72 a gallon and propane starts at $2.89 a gallon in 2011. By 2015 these prices rise to $4.37 a gallon for B5 and $3.42 a gallon for propane. By 2030 in the high case B5 is $4.82 a gallon and propane is $3.79 a gallon. In the low case B5 starts at $3.27 a gallon with propane being $2.40 a gallon in 2011. By 2015 these prices move to $3.43 a gallon for B5 and $2.57 a gallon for propane. Finally, in 2030 in the low case B5 is $3.22 a gallon and propane is $2.37 a gallon. Values for E85, B5 and propane can all be found on page 25, Table 6 of staff’s document for this workshop.

The final slide I plan on presenting today is our price forecast methodology for transportation, natural gas and hydrogen. Staff intends to use the same fixed margin methodology established in our previous IEPR work. Both of these fuels will use natural gas projections consistent with those used by other offices and talked about earlier today.

In the case of CNG, the Henry Hub forecast will be transformed into a California Citygate with margins of five cents and two cents in the low case being added to that price to turn it into a Citygate price. If the Natural Gas Office provides us with actual Citygate forecasts we will use those Citygate forecasts instead of the Henry Hub forecast. Then PG&E transportation CNG cost margins of $1.62 per therm will then be added to the Citygate price. And then the appropriate federal road excise tax of 18 cents per GGE and 8.25 percent sales tax will then be added to create a final retail price.

In the case of hydrogen, which there still has not been an established way to sell hydrogen at the retail level at this moment, instead we will rely on the 2002 Argonne National Laboratory study in order to generate our prices. In this price methodology we will use the same California Citygate prices as the CNG price format, a refining and retail margin of $1.25 per GGE will then be added to those prices, a reforming cost of 24 percent of the Citygate price will also be added, and then a 8.25 percent sale tax will be applied in order to bring it to its final retail price.

This is the last slide of my presentation before I turn it over to Malachi Weng-Gutierrez to discuss our electricity rates. Are there any questions at this time regarding my presentation?

MR. OLSON: Going back to one of your earlier slides where you've got the US per capita gasoline expenditures, I think your staff has been some work identifying an average $150 million a day spent on petroleum purchases in the state. And I've seen another study trying to segment the cost of imported crude, what that value is in GDP. And apparently a study by a group in the State of Washington, that has doubled in the last ten years, it's about 4.65 percent of GDP. Any way of comparing that to California for what we spend on petroleum and the incremental crude oil, basically imported oil aspect of that? As opposed to just per capita? And then that kind of begs the question, is that significant?

MR. EGGERS: Currently I have not looked at it in a California-specific level. It is something staff can start looking into if that is so desired. It should be doable, to say the least. Gordon, would you like to comment on this particular subject?

MR. SCHREMP: Yes, Tim. This is Gordon Schremp, Energy Commission staff. Also as part of that analysis, which I think we can do, we would have to estimate what the imported crude oil price is. We wouldn't actually have the individual prices by source country. But we also have to take into consideration, with rising prices and rising costs and rising imports that are on one side of the ledger, I'm sure there is some sort of economic benefit, if you will, to the oil production industry in California with those rising prices. There is some economic gain in jobs and activity associated with that.

So how we handle sort of both sides of the ledger is maybe not clear to us at this point in time. But we can certainly continue the discussions and obtain some additional guidance from you.

MR. EGGERS: Are there any questions from workshop participants? We have one question right here.

MR. FERGUSON: I sympathize with trying to make price forecasts but the most interesting factoid that I know in the crude oil industry is global production. And the EIA numbers are what I look at. And basically for the last five-plus years global crude oil production has been essentially flat. As I recall, there was a small peak above the plateau in, I think, April 2005 that was only barely suppressed in the heyday of the 2008 $140 price range. I haven't seen what is in the EIA forecast for global production but it strikes me that there is a lot of theory out there that suggests that global production is never going to increase, in which case my guess is that your high price scenario is probably too low.

I hesitate to suggest that you use a higher one because I don’t know what you would use for that thing. But I think it would be worthwhile for this commission to consider the possibility that we have in fact reached the maximum crude production that we’re ever going to see and try to sort of figure out what the implications of that are for the State of California.

MR. EGGERS: Crude oil production and demand does play into these price projections for both the EIA forecast that we are using and the Global Insight forecast we were using. I don’t have any inputs as far as what demand would be in the IHS Global Insight case. But in the case of the high 2009 reference crude oil price case that we are using for our high case, production is increasing in this particular price forecast. I also do know from analysis done by the EIA that the difference between these two particular forecasts in 2030 is roughly two quadrillion BTU difference in demand, is basically what is separating these two price forecasts.

Any other questions? I think we have one online.

(WebEx question presented by Gina Grey of Western States Petroleum Association – no audio available so written question is presented.)

This particular question is from Gina Grey and she is asking: Are the E85 prices adjusted for energy content?

And, yes, they are.

Any further online questions?

(No response.)

Then I'm going to turn it back over to Malachi in order to present our electricity rates

MR. WENG-GUTIERREZ: Thank you, Ryan.

I'm going to start just by answering the second question that Gina had asked in the one that she had commented on. If you could pull that up again. The question related to, are we considering whether or not alternative fuels exist to replace the decline in demand of gasoline? And I'm assuming in our analyses. So I can say yes and no.

I guess why I would say that is because a certain amount of our decline is actually declining demand not because of substitution with alternative fuels but actually declining demand because of pricing, declining demand because of policies coming into place, declining demand because of efficiency changes in the marketplace, of the actual vehicles coming to market. So to that extent we are not really substituting gasoline with an alternative fuel, we are substituting it with an efficiency gain or a price impact.

But there are certain volumes, certainly in what I presented from the 2009 IEPR that we will have as part of our 2011 IEPR, where we will be making the assumption that alternative fuels will be supplanting gasoline demand. And I think the question here is whether or not there are sufficient commercial quantities of renewable and alternative fuels to fill that gap. And I think that's probably something that we will be discussing in our policy analyses, certainly something we will be talking about in our discussions of specific policies, RFS2 and LCFS come to mind as being fairly significant. And certainly I think we touched on those in 2009. We certainly will talk about them to a greater extent, I think, this IEPR cycle. And I also want to note that the upcoming – not to plug our workshops again, but the May workshop, I think, when we are going to be touching on infrastructure I think we will be looking at production capacity and the implications for how that is going to come to market and whether or not those are reasonable.

So that would be my response to her second comment there. Sorry about that, Gina.

Is there a follow-up question then?

(No response.)

Okay, I will just go ahead and continue with the presentation.

For electricity prices I basically used a similar methodology that I used in the last IEPR cycle to derive the transportation electricity prices that I would be using, that we are going to be using in our models. It’s based on rates that exist today, those which are out there and those discounts that are offered by the utilities today. We did update our rates to the existing rates so we are reflecting what the current rate structure in the MOUs and IOUs that we looked at. As you mentioned, Tim, to a certain extent it is a marginal analysis. So in those cases where we have a tiered pricing structure where there are both single and dual meter rates offered we did attribute a portion of the overall average number that we calculated to the single meter situation as well as partially to the dual meter situation. And, again, I will touch on that a little bit later.

Overall to come up with a California average number we used a sales-weighted average for the state using 2009 consumption volumes for the different MOUs and IOUs that we looked at. So again it’s kind of a sales-weighted average across the entirety of all California. That methodology was used to come up with our base year value, which we then grew in accordance with what the demand analysis office used as their basis for their electricity growth over time. So we are going to use the same approach.

So what Chris used as his growth pattern for high and low prices we would then apply to our base year number and grow throughout the forecast period as well. And the justification for that really is that we see no reason why the price impacts that they are representing in their price forecast wouldn’t also apply to the tariff rates that specifically applied to electric vehicles. I mean, there could be situations where you wouldn’t do that but our assumption is that they will be constant.

So we looked at five utilities. They represent about 90 percent of overall consumption in California, at least residential consumption for electricity: LADWP, PG&E, SMUD, SDG&E and SCE. As I said, for the marginal analysis we had to come up with an estimate of what consumption would occur on a monthly basis in the household that would be attributed to electric vehicle use. And then in the case of the single meter rates we would apply that as an add-on to the average consumption that’s occurring in that month and then come up with the overall price. And then, obviously, for the dual meter we would apply it to the lowest tier and let it go until it exceeded the baseline allotment amounts. They really didn’t because the consumption levels were so low. But we did have to come up with that number.

So I did a couple of analyses, one of which was I took a look at historic data. It is FERC data that was reported for PG&E, SCE and SDG&E for rates that were dual meter rates. So I’m assuming that those consumptions for those rates were only associated with electric vehicle consumption. Again, the tariffs that I looked at were specific to electric vehicles. So in the case of PG&E I looked at the E9 rate B, which is a dual meter rate which has its own set of prices and everything, and I could see how many people and how much was consumed and then estimate the monthly consumption according to that. So I did that and I made some assumptions about overall electricity efficiency of the vehicles. And then I came out with this monthly VMT as well as this monthly consumption number. And it ended up being 188 KWh per month. And that was just using the FERC data as the basis of that. And that's the 2009 number, I believe. So it's using FERC data from 2009 to come up with an estimate of per month KWh consumption. That was something I could kind of peg my analysis to, to see whether or not I'm in the ballpark.

The second method I used to determine, something that I had done last IEPR cycle, was to come up with a potential range of VMT that you would observe or use an electric vehicle for, look at the distribution of efficiencies that are published for different electric vehicles in the marketplace, and then use a Monte Carlo simulation to estimate how much would be consumed by any household with these vehicles in them. So basically a range of VMT, a range of efficiencies, how much would be consumed given the distribution across those two variables. And I came up with 175 KWh per month as a mean value. So there is certainly obviously a wider distribution of potential consumption but the mean was 175. And I thought the 188 and 175 were pretty close, that's not too bad. It's in the same ballpark, I thought.

In my analysis at the end of the day I wanted to adjust for seasonality, differences in VMT – given an analysis of CalTrans and, I think it was, High Comp (ph) data, there is a difference in those months of about 3.5 percent plus or minus. So it's about a range of seven percent for VMT travel. And I applied those to the final numbers that I used into the model as my summer and winter monthly consumption values. In addition to the VMT seasonal differences which I just mentioned, the rate structures that exist have seasonal differences as well and I accounted for those in my estimation of the final marginal price. So I am applying a VMT in summer to the summer rates to get the number that I got.

Now, something that I think that I would like some feedback on – certainly there are other studies out there but the one study that we used last year and that I kind of plugged in in this analysis to come up with these prices was a PG&E study that I think was performed in 1998, which showed that there was 88 percent off- charging, eight percent partial peak and then four percent on-peak charging. That obviously is an older study, there have been other more recent studies. Certainly it would be interesting to hear what people have to say about what would be the appropriate load profile of an EV at a house when they charge. There is a lot of uncertainty about that. And that may influence the final rate that a residential consumer would see. So any information that people can provide or participants in this workshop can provide on that would be helpful.

What we did to determine whether or not the dual metered would be allowed versus single metered was we basically went out and we checked to see whether or not there were any regulations prohibiting the use of dual meters in certain regions and then we aggregated those for each of the utilities and applied it as a percentage for the distribution across the single and dual metered rates. For example, for PG&E certain counties and cities don’t allow dual metering so we said they had to have single meters in those situations. Then we weighted it by those counties, which allowed and which did not allow.

And I just wanted to show, for the FERC data I looked at SCE and PG&E for the last eight years to see what the per KWh revenue looked like, just to get a sense again of whether or not the estimate that I was using as a statewide number looked reasonable in the context of existing reported revenue per KWh values. So you can see here that in 2009, which is kind of our base year value, the tariff rates that I looked, which were the two dual metered rates, they came out to be an average – the green line is the sales-weighted average number – of over 14 cents per KWh. The number that we were using as the basis of ours was 12.6 or 12.58 cents per KWh, was the number that I calculated for that base year of 2009. So ours was substantially lower than this sales-weighted number value. But it is kind of in the ballpark, certainly between these two utilities.

So this is my proposed electricity residential retail rate value. Again, in 2009 the initial value is at about 12.6 cents per KWh. You may recognize the slopes of these two lines. These are again the high and the low rates of growth that Chris Kavalec spoke to this morning. As he mentioned, he had some concerns about the dip in the price in the short term. That may not be reasonable and we may want a straight line from our base year value to the 2030 value there just above 13 cents per KWh, as opposed to having it drop down in the near term. But again I think that’s something that Chris already asked for feedback on and we will look to the comments made on that to gauge whether or not we should continue with this low value here or a different alternative low.

So that was my proposed retail price rate that I have for electricity. I certainly considered that the market for electric vehicles is not only residential. There is certainly potential for commercial fleets to take these technologies on. And so perhaps it would be appropriate to apply some type of commercial rate to those instances or those fleets. So I certainly considered how we would do that. One of my thought was that we would use as the basis of a commercial a general service rate as opposed to a residential EV-specific rate. So it might be something more generic but we could apply that rate to the commercial applications in our modeling work so we would have a differentiated price for residential versus commercial applications. In the end, of course, the commercial rate would still have to be grown, I think, in a consistent manner with what we're seeing for the residential side and a consistent manner with what Chris Kavalec and the Demand Analysis Office is proposing for their growth rates.

And then just as a final slide I wanted to highlight some of the assumptions and simplifications in this analysis. Obviously, there are differences in overall consumption for single family homes versus multi-family dwellings. The consumption patterns are different, the tariffs applied to them are different, and those really weren't considered specifically. We really didn't consider how much significantly subsidized public charging was offered or free charging. We are just trying to develop a price forecast so have a price value that we are going to set as an input. If there are in the short term free charging stations, like across the street in the parking structure where, you know, there is no credit card slot for me to put in when I pull up with my EV, there is no way for us to represent that in the short term. And I haven't accounted for that in my price forecast.

Also third party sales providers of electricity, I don't have a good grasp of what prices they are going to bring to market, what overheads they might have, what types of returns on investment they will need in order to make their businesses viable. So I haven't included any of that type of cost or charges into the rates that we have here. These are purely rates from utilities that exist today, grown by the growth rates that were discussed this afternoon, or this morning.

And then, as Chris mentioned, the two different cases have varying degrees of RPS compliance in 2020. The high case is fully compliant with RPS, which again implies a certain amount of cost increases and price increases. And then the low case does not have a full RPS compliance. So again that has impacts on the retail prices offered to consumers.

And then lastly, there of course is the option that, going through ratemaking, a utility could subsidize or lower the rates for EV uses and then try to recover some of those costs in other rate structures, other non-residential or other residential rate structures, it doesn’t matter. That’s not something that we looked at. We had an existing rate structure today that defined what it was, the distribution across those tariff rates, and then we just grew that. So we haven’t taken into account any type of future subsidization. And if we were to do that it might be relevant to discuss with the Demand Analysis Office if the industrial sector is impacted by those subsidies. You know, if they have a rate increase for a lower rate in this residential rate we might want to make sure that it is consistent.

And I think that’s the final slide that I have for my electricity retail rate forecast. So if there are any questions from the commissioners

MR. OLSON: Just another kind of reminder. The electric transportation rate and tariff topic is evolving quickly, changing almost every day. It is good to get connected up to the CPUC, OIR, smart grid, electric transportation. Tariffs are a big part of that. It would be good to get into our record what the utilities are planning, including SMUD, what they are planning in terms of their specific tariff schedules. And, I mean, it's a ground truthing thing that we need to add to this that will probably help you in reducing those uncertainties.

MR. WENG-GUTIERREZ: Just to speak to that, the level of uncertainty with smart metering and smart grid, all of those things play a role in how the rates and tariffs are implemented. So in some instances we are assuming that there is a metering rate but in fact if it's a single meter maybe they could go to a dual meter if they had a smart meter at their house that allowed them the capacity to meter just one outlet or something. And there are lot of solutions out there. It is just difficult to quantify them and then come up with this statewide average.

So if there are no more questions from the commissioners, are there any other questions in the room?

(No response.)

All right, if there are no questions in the room then I think we will go to Gina online.

MS. GREY: Hello.

MR. WENG-GUTIERREZ: Hi, Gina.

MS. GREY: Sorry, I wasn't too sure if I had been unmuted or not. And I do apologize for having to sort of revert back to some of the earlier presentations but we are having a little bit of challenge here in terms of the connectivity. So I would appreciate a minute or so just to address the two questions that I had submitted earlier.

First of all, on the petroleum reduction goal I did hear the response. I think WSPA has every year raised concerns about this as being a goal of the IEPR, recognizing that it was in 2076. However, in terms of the way it’s stated here and in terms of listening to the presentation that was made, you know, the comment that was made that basically the commission would like to emphasize these more, the comment really goes to the fact that when I heard the response it was more a case of, well, there are things that occurring such as price issues, such as efficiency on the vehicle side, et cetera, that are leading to natural petroleum reduction. That is far different from what appears in this and in previous IEPRs to be a policy direction that the state is taking to reduce petroleum demand, et cetera, and any policies that may flow out of the IEPR analysis that directs the state to do X, Y, Z that would then lead to additional petroleum reduction. When in fact the other side of the coin, which is the supplanting of the petroleum with other transportation fuels and vehicles, that case has not necessarily been made yet.

And so I think it just goes to the point that, fine, if there are natural events that are occurring that are leading to petroleum reduction that is certainly one issue. But the other issues is whether or not the state through the

IEPR is going to be developing policies and recommended actions that then force more petroleum production when potentially the backstop is not quite there yet. So it just goes to WSPA's ongoing, you know, making sure that there is going to be adequate and reliable affordable transportation fuels for the state to run on.

So I don't know if anyone has a comment on that, I'm not necessarily asking for a comment. I just thought I would supplement my question with where we are headed on that.

MR. WENG-GUTIERREZ: Thank you for the comment, Gina.

MS. GREY: No problem. And secondly, on the hydrogen I'm not sure if my question was really clear enough. But we do see from another state agency a significant push to have the oil industry put in hydrogen facilities and infrastructure at retail. And so I guess we are sitting here trying to understand if in fact the state doesn't appear to be studying hydrogen in terms of the demand and in terms of the supply issues. Where is the connection between the state agencies here when in fact a state agency is identifying that there is going to be a demand, it's going to be significant, we need to provide the supply? And on the other hand there is a state agency that is doing an Integrated Energy Policy Report that is not going to be addressing, currently anyway, hydrogen.

So our comment was we would definitely like the commission to address hydrogen both in terms of demand and supply, recognizing the challenges as you pointed out on the vehicle side, but also recognizing that there is a big forcing mechanism in another state agency to enact hydrogen infrastructure into the State of California. And we are not sure within the overall context of alternative and renewable fuels, et cetera, why that would not be a major component then of the IEPR.

MR. WENG-GUTIERREZ: Well, I hear your question and your comments. I think there are some complications with including a demand side analysis of hydrogen. I think the supply side is something we can touch on in our infrastructure analysis workshop that is coming up. And I think that really should probably touch on both of your questions. Today’s discussion was more on our demand analysis work. My point with hydrogen is, you know, we just don’t have a clear picture about how we can include that given the uncertainties in pricing.

The infrastructure side, I think, is something different. That’s something we can certainly take – it has its own set of challenges and things that we want to take a look at.

MS. GREY: I guess my question, though, would be if there is another state agency that supposedly has identified a demand and they have put some numbers to it, should that not be coordinated with you folks in the sense that you could also utilize either the same estimates or come up with your own estimates in terms of what the demand seems to be. You know, understanding that within your detailed report you do have some forecast to indicate potentially a drop actually in hydrogen demand within the next few years. So all we are asking for is basically some more coordination between state agencies on this so we don’t have one hand doing one thing and another hand doing another.

MR. WENG-GUTIERREZ: Well, I can't guarantee that we won’t be doing different things on either hand. But what I can talk to is that we can certainly look at the other state agency’s activities and look at the assumptions that they have made a see how we might incorporate those values into our work.

MS. GREY: Okay. I think we would appreciate that and basically I think it would also be very helpful for the commission in the sense of the AB118 work that you are doing, to help assess also the AB118 program. So I think it has dual use.

MR. WENG-GUTIERREZ: Sure. That is definitely true. And again I think, even in the context of the AB118 work, the May workshop should touch on many of those issues.

MS. GREY: Okay. Thank you.

MR. WENG-GUTIERREZ: Thank you.

Any other questions from online?

(No response.)

Okay, then I think I'm going to go ahead and turn it over to Gordon for his presentation.

MR. SCHREMP: Good afternoon. My name is Gordon Schremp. I'm a Senior Fuels Analyst in the Fuels and Transportation Division of the California Energy Commission. Welcome to the dais. Chairman Weisenmiller, Commissioner Boyd, Mr. Olson and members of the audience and those online.

I will be covering a wide variety of topics, it almost sort of a catch-all, to what else we plan on assessing and analyzing as part of our work in our office associated with the 2011 IEPR. I will be circling back to what Malachi and Ryan Eggers were discussing earlier on some aspects of the other analysis where we do some post-processing work and assessments. And I will make clear what those are. And since I'm covering, I think, a more diverse set of topics the dais should feel free to interrupt me at any time with questions they may have rather than wait until the end, whatever your pleasure might be.

So here is a laundry list of the topics I will be covering during my presentation. The first is an examination of two policies, one federal and one state. They do, we believe, impact or demand forecast for both gasoline and diesel fuel. I will also be looking at infrastructure assessments associated with our overall demand and changing mix of transportation fuels as well as going into a discussion of two major areas of advanced biofuel technologies that are intended to produce transportation fuels. And then I will be discussing crude oil. We do crude oil analysis as part of our IEPR work every two years, both import and infrastructure assessment. And this will also include what we refer to as crude oil screening, our work associated with the low carbon fuel standard. And then the final laundry list of a number of topics that will also be included in our work and assessments: marine oil terminal engineering and maintenance standards, or MOTEMS, the new ozone standard that Malachi mentioned earlier, we do look at agricultural commodities because of the increased use of biofuels sourced from agricultural products as feedstock, import tariffs are becoming more of a subject du jour, as well as blending credits – those have to do with the renewable identification number, and I will talk about that – and finally I will be briefly mentioning the BP oil spill in the gulf last year as well as energy security, which has been a topic of the Energy Commission in years past.

Now before I continue, just to make sure we’re all on the same page here, I am not presenting any results of our work because that work has not yet been completed. And this is basically telegraphing to those on the dais and those in the room and online what our intentions are and what topics we would like to assess as part of our IEPR cycle this year.

So the first of the two regulations I will start with is the federal regulation, that being the Renewable Fuel Standard or RFS2, because this was revised to include higher quantities of biofuels over the period of the regulation. So this is essentially a federal mandate, it is really not optional. But how the obligated parties comply is optional and there is flexibility there that does include, in fact, credit generation and purchase as a way of compliance. And I just want to point out that, in comparison to the state policy of the low carbon fuel standard, this is not a per gallon regulation. You have to meet your obligations for total use of renewable fuels and/or credits.

Now some of the impact assessments we will be looking at are what are those demand projections for various types of ethanol as well as biodiesel. And for ethanol, certainly, we do look at feedstock when it comes to traditional ethanol production as corn. And I’ll touch on that a little bit later. And we will be looking at what level of displacement of gasoline is occurring in California compared to our initial forecast that Malachi was mentioning earlier. And then finally and very importantly what infrastructure might be necessary to bring into California and distribute an increased concentration in total renewable fuels.

This is a slide that illustrates the various categories of the renewable fuels under RFS2. I have highlighted one category, cellulosic biofuels. Those two numbers are billions of gallons. So you see the first one for 2010 is 100 million and the one for 2011 is 250 million gallons. The reason I point that is because this mandate for those minimum volumes in those categories does appear to have a bit of challenge at this point in time. Both of those numbers have been drastically reduced by USEPA in light of the fact that there is an inadequate volume of commercial scale cellulosic production in the United States at this time. And so the 250 million gallon mandate became 6 million gallons in 2011 and it’s likely the 500 million gallons for 2012 will be significantly reduced. We will find out later this year when USEIA does their initial assessment then sends a letter to USEPA with their recommendation on what to do depending on how much capacity they see coming up on a commercial scale.

So there are issues going forward both in terms of certainty and preparation by obligated parties on how to comply with this element of the RFS2. And it is possible that there may be some more significant revision that Congress undertakes on this as time goes by. We will see what those developments are. But we intend to also look at an assessment of cellulosic, how well that's progressed nationally and internationally, and we what kind of supply potential there might be over the near to mid term.

Malachi's forecast based on modeling and consumer preference surveys does result in showing that gasoline demand is declining over time, primarily a result of increased fuel economy standards as well as price signals. But the post-processing work we do is looking at those fair share obligations to use increased renewable fuels primarily on the gasoline side of the equation for RFS2, not necessarily on the bio or on the diesel side because there is only a very modest – essentially one billion gallons nationwide – of biodiesel under RFS2 over the near and mid term.

So really this is something that RFS2 does significantly push down our initial forecast. And these are the 2009 results, not our 2011 results. As you can see, the dotted lines are how much of a change the initial forecast is lowered by just the RFS2 obligation. So I think, back to

Gina Grey's question about sort of a displacement effect here, this is that. You know, more renewable fuels displacing gasoline hydrocarbons. On the other side you also notice there is a red line on the bottom of this chart and you will see a dotted green line that does go up at a significant rate and then sort of plateau at two billion gallons. And that is E85. Well, the reason we see an increase in E85 in this post-processing work is because the amount of ethanol that one would need to get into the gasoline in California's fair share is more than can be obtained by just putting it in gasoline at a concentration of ten percent by volume.

So what I mean by ten percent by volume, well, that's referred to as a blend wall. There are many challenges to using ethanol in a concentration greater than ten percent by volume low level blends. Many of you may be aware that USEPA has issued not one but two partial waivers for an E10 limit in low level blends up to E1. Staff believes that, even though those waivers have been issued, there are many other limiting factors that prevent marketers to go to E15 at a rapid pace. We believe in California, at least for our assumptions – and we welcome comments on this – we are assuming that an E10 blend wall in California will remain over the forecast period.

E15 primarily has issues in California specifically with our gasoline regulations for reformulated gasoline being predicated on blends of gasoline with ten percent ethanol in the testing and emissions data generated and the modeling work that went into that effort. So going to E15 would require a modification of those state regulations that would take probably at least three years if not more if one wanted to go down that path. All vehicle owner original manufacturer warranties for those vehicles still under warranty are all void when the owner of the car uses gasoline in excess of ten percent ethanol. So that's a very important issue or barrier that would need to be modified and possibly over time that can be. There are compatibility issues with dispensers on using ethanol blends in gassing above ten percent. The dispenser manufacturers are aware of this and are trying to receive approval for new equipment that can be used for that use.

And I think most importantly from a retail station operator and owner perspective is that there is a liability for misfueling. Many of you may recall when lead in gasoline, or tetraethyl lead, was phased out and unleaded gasoline was used in the United States and phased in over a period of years, for that change in the retail infrastructure there were actually different sized nozzles deployed, where you actually really couldn't put leaded gasoline into your unleaded vehicle unless you held back the nozzle and let it sort of drip into your tank past that little safety device installed inside the tank. So there was a physical change at the retail dispensers to sort of prevent misfueling.

Well, in this case there is no physical barrier to prevent that. And therefore USEPA is depending on warnings posted on dispensers to provide enough information to a consumer that pulls up to the dispenser to not misfuel into their older vehicle. I failed to mention that the waiver, the two-part waiver that USEPA has ruled on, is for vehicles 2001 model year and newer, which is about two-thirds of the existing fleet in 2011 for light duty vehicles and sport utility vehicles. So this is a rather significant portion of the total fleet in existence.

So that liability of misfueling and potentially causing damage to a vehicle or drivability issues is something that most retail station owner associations believe would come back at their ownership. And those people that own those stations now are not necessarily big oil. The percent of stations I've seen as recently as 2009, I believe, that are owned and operated by vertically integrated coil companies is two percent nationwide. So that number has become very small. I know people see branded stations everywhere but the vast majority are franchisees or lessees, like a McDonald's or Kentucky

Fried Chicken. So not vertically owned and operated by the majors. And other fact about retail is that in excess of 50 percent are owned by one person. That's all they have, one station, one location, not multiple stations. So it's that group of people who would be subject to this potential liability from misfueling, which causes them and even their associations to express concern about moving forward at this time.

And I think a final point on E15 is recent attempts in Washington as of even up to yesterday trying to put language in budget-related bills that prevents funding for E15 to move forward with USEPA's help or other means of trying to prevent that. So there is some opposition to this move.

Now, as I mentioned, assuming we are at ten percent limit and we need even more ethanol to meet our fair share, how would that get into the fuel supply? Well, certainly E85 is a means of doing that. However, there is an infrastructure issue – I know Gina mentioned infrastructure on the phone in her questions. There is a legitimate E85 lack of infrastructure at this time. And this slide from our 2009 work, which will be updated, just illustrates that there is a broad range of incremental E85 dispensers that one would need to meet our fair share compliance that number rather significantly, upwards of over thirty thousand new dispensers.

So certainly this has a timing element, this has an economic cost – who is going to be paying for these? – and what kind of return on investment is there for the service station owner. Because keep in mind the RFS2 obligated parties are not retail station owners. They are not required to put in this kind of infrastructure to enable E85. And the manufacturers of vehicles are not obligated parties and required to produce a minimum number of flex fuel vehicles so that there are enough of those vehicles in California. Which is, oh, by the way, also part of our analysis regarding adequacy of infrastructure both to dispense as well as to utilize. And so you are welcome to look at our previous work, we have a lot of detail in there. But we plan on replicating this process, if you will, and then certainly updating it. And we do welcome the input of people like Propel and Pearson and installing these kinds of dispensers. I think there is very 50 to 60 locations that do have E85 available at retail in California at this time. So we certainly welcome some of their expertise from their recent experience of doing these installations.

The Low Carbon Fuel Standard, unlike the federal, is a per gallon ratcheting down goal, ever lower carbon intensity, starting off modestly at first and becoming a little bit more aggressive over ten years. So it’s gasoline and diesel, it’s not other fuels or even lube oils and other non-transportation fuels. And it went into effect for obligated parties January 1st of this year. However, there are some elements of the regulation yet to be finalized. And these are non-trivial, these are important and I think a lot of parties are aggressively working to reach some sort of place where there is finalization on these aspects. And these include a credit trading system that you could buy and sell credits to achieve compliance as well as transparency of what those values are; crude oil screening, that I will talk about in a little bit; and indirect land use for carbon intensity and how that’s changed and how that will change the ability for people to comply and make it easier or harder or the same.

Those carbon intensities are in two pieces, if you will: direct emissions and that indirect land use change category. So that’s the one that you see the numbers there, the second column from the right, 30 grams of CO2 equivalent per MJ. Those are possibly going to go down to 15, it’s not sure yet. A lot of work has been done by people. The Air Resources Board has a technical task force essentially or stakeholder groups that have been providing a lot of analysis and input. So later this year – I don’t know exactly when – we expect to see some sort of finalization of this aspect, not only for corn-based ethanol but likely for things like sugarcane-based ethanol with that indirect land use change. The value is in how much that may change.

There are some other important aspects of the low carbon fuel standard analysis. And that is we believe there will be a requirement for certain types of renewable hydrocarbons that will be necessary to be able to achieve compliance. Without that we reach what we call infeasible solutions. You know, by 2017, 2018 we don’t know what kind of renewable fuel one could use to achieve compliance. And that is even with credit trading going on. Or stated another way, building excess credits earlier on in the program and then using them to help achieve compliance in the latter years.

So what does that look like? Well, some preliminary analysis shows – the bars on the bottom is when there is some generation of excess credits above and beyond what you would need to sort of balance out collectively, as all the obligated parties in California. So this is based on our 2009 forecast. And, of course, we will be updating this in two aspects. One, we will have new forecast numbers and there will be hopefully sometime soon a resolution on what the indirect land use change, how much that will be altered; and then how much the per year goals may or may no be changed and what does that mean to calculating these kinds of debits and credits. So this is just an example.

Clearly, we believe the industry is going to over-comply in the beginning to build up credits and then use them as the program progresses. But as you can see in this slide as an example, come 2019 or 2020 then you would get into a negative situation than what you would use. Which leads us to believe that it will necessitate the use of lower carbon intensity hydrocarbons that are mixed with base gasoline and base diesel to lower that carbon intensity further.

Another very important aspect besides the post-processing of our demand forecast is, what about the infrastructure? The infrastructure is both for crude oil, traditional fuels, petroleum-based fuels, as well as renewable fuels. And this graphic is only meant to illustrate I think part of the complexity of the system in California. Liquid coming in, the blue lines, and then being dispensed on the black lines, which are product pipelines in this case, petroleum product pipelines. And then showing multiple states because the region is tied together in supply. There are 22 refineries in California, the refineries in Washington state. The other states in this graphic have no refineries at this time. And so Nevada relies nearly a hundred percent on California for its transportation fuels and Arizona about half of their fuel. So that’s important when we look at infrastructure and we look at our demand forecast for imports. Because how demand is changing in those neighboring states supplied from California facilities will have an impact on our infrastructure assessment.

So this graphic is a little bit more detailed, where you see Arizona is supplied from two different directions, refineries to the east of Arizona in El Paso, Texas and in New Mexico and those in the west. And so we look at demand forecast changes in Arizona, we look at demand forecast changes in Nevada for all three primary fuels as well as renewable fuels. We will also assess what are their fair share obligations under RFS2 and put that into our calculus to determine incremental barrels of petroleum products coming out of the west to both of those states.

There is a new element in our analysis and that is a brand new pipeline that is coming from the refining center around Salt Lake City, heading down all the way to northern Las Vegas. This is the UNEV, Utah-Nevada pipeline. It is a petroleum product pipeline delivering primarily gasoline and diesel fuel initially. About half the initial thirty thousand barrels a day will go to a terminal in southwest Utah and the remaining balance into northern Las Vegas. So what we will now have to do is look at some scenarios of how much will this line actually displace coming out of California. So that will mean more supply for California and a little bit less demand in the future. So we intend to suggest a bracketed range of what that might be as part of our analysis.

There are two main areas of advanced biofuel technologies that we intend to put some effort in to cover a broad range of topics and give as much substantial information as we can put forth. And, as listed here, we are going to lay out the various types of primary technologies for Algal fuels. What is their supply potential? This is usually a very important and often not asked enough question. There may be a very good technology but it may have some significant supply potential. So we intend to illustrate what that can be and this can be substantial actually for Algal. Estimated production costs are very important. This is probably a challenge we are seeing with cellulosic at this time. We will look at pilot status as well as commercial. Some of that is actually starting. And the final issue is suitability, what you see in the chart at the lower right. The yellow areas are thought to be more suitable regions for both the open pond as well as the closed photo-bioreactors using natural sunlight, not artificial light. So Algal fuels are very promising in a number of aspects. They have quite a bit of co-products that can be used, they have a lot of versatility in what kind of hydrocarbons or what you can do with the oils, actually, as well as what you can do with the biomass material that is powdered and you can actually use that as an input to a refinery. So we will try to do our best to cover this. And we definitely appreciate input from stakeholders who have far greater expertise than staff does on this subject matter as we move forward.

The other main biofuel technology will be renewable hydrocarbons. This is Neste’s facility in Porvoo, Finland that you see a picture of. And they are producing renewable diesel fuel. We will look at other types of technologies for bio-refiners. You are basically taking a specific feedstock and creating long chain hydrocarbons in either the gasoline, diesel or jet fuel boiling range. You know, you see Branson talking about Virgin Airlines and using certain types of renewable jet fuel. Well, this is an example of something like that.

I think an important element of these kinds of renewable hydrocarbon fuels is what people refer to as “drop in”. That means really no special infrastructure. You can blend these in the gasoline boiling range, you can put them with gasoline blend stocks in common storage tanks, pipeline distribution, nothing special at retail, nothing special at the intermediate distribution infrastructure. The same goes for jet fuel and diesel fuel. So that’s an important element moving forward when one looks at infrastructure requirements for a new type of fuel such as this. And once again to reiterate, we believe this type of fuel is something that one would need to help achieve compliance with the LCFS in the latter years.

I will switch gears to crude oil. California does produce crude oil. We have produced a lot of crude oil, as you can see by this long-term historical output of crude oil. But even over the entire period of crude oil production in California it is still not even eleven months of total global crude oil use, come 2010. So over 125-plus years and, you know, that sort of puts it in perspective. So California's crude oil production is declining. So that's one reason we expect to see more imports, because our own production is declining. So that's an element that goes into our analysis, how quickly is that declining?

Another important element is, is the demand forecast in conjunction with our refineries? So if our demand is going down – as Malachi was pointing out and as I illustrated – over time for a number of reasons, will the refineries continue operating and producing fuels that in some ways start to become in excess? They process crude oil and it makes a certain amount of gasoline, diesel and jet fuel. If you are now seeing declining gasoline, what do you do with the excess gasoline? Do you just keep making more and more of it and then you think you will, you know, sell it overseas? Well, we don't think that's a very realistic scenario. And I will touch on that in just a minute.

First, this is an illustration of our high and low declining estimate or forecast for California crude oil production. And so we tend to replicate this approach when we do our 2011 work. And I will, in fact, be presenting this information at our May 11 workshop, the results of this analysis. So that’s one aspect of it. And the other, as I just mentioned, is: will the refineries business as usual over the entire forecast period remain the same? Meaning the same number of refineries in California or operate at the same level of utilization, which is the chart at the top.

We don’t think that’s going to be the case. So we are going to include a sensitivity or a scenario whereby we see a decline either in the utilization rate or the overall capacity. The result is going to be the same. We are going to have a decrease in the crude oil import forecast from our base case, if you will, and there would be sort of an opposite increase in transportation – you know, some increase or change in the transportation import forecast for both renewable and traditional hydrocarbons. So we just want to let you know that we are not going to do what we did last time and just say business as usual, same utilization rate, same number of refineries operating for all twenty years.

Part of that assessment besides when you come up with an incremental volume of foreign imports or water-borne imports greater than we are today, where will that come to? Well, there is a project in the Port of Los Angeles, the upper chart, and you see that location for Berth 408 at Pier 400. That project has been worked for many years. I think this is going on maybe seven years now. They have received, I guess, final approval of the draft EIR/EIS in 2009 and ongoing negotiations continue with the Port of Los Angeles to obtain their final permit. So this is by no means a given that this will happen. But we do keep an eye on this because we believe that if this type of facility were to be constructed we believe that would be adequate incremental import capacity to handle the next 20 years for crude oil imports for Southern California. So it is an important facility or a capacity like that.

The second graphic is a new proposal for the Port of Long Beach competing with the Port of LA just to the right of that. And this is the T-126 Berth and what they refer to as Pier Echo. So they did a request for proposal and they modified that. It was initially transportation fuels but then they modified it to allow the importation of crude oil as well. So we are curious and very interested in what responses the port did receive and if they are going to continue moving forward on this kind of project.

As I mentioned, the Low Carbon Fuel Standard does have another element. It is referred to as crude oil screening. And crude oil screening has to do with the concept of wanting to minimize the use of crude oils that are potential high carbon intensity crude oils. Examples of those kinds of crude oils given by the Air Resources Board are usually things like your mining bitumen deposits in, say, Canada and using energy to upgrade that material and make a synthetic crude oil. Another example is if you are using a lot of steam injection, thermally enhanced oil recovery.

And so what the Energy Commission staff has done is a lot of work to come up with a list of what we call marketable crude oil names that are available globally and that have been imported to California. That list in excess of 250 – I think it is 257 – names and we have completed our initial analysis of screening them. Meaning a certain number of them are potential high carbon intensity crude oils. And you can see the results of this initial work in our pie chart on the left. And you see things like TEOR, thermally enhanced oil recovery. That’s why they would fail this initial screen. It doesn’t mean they can't be used it just means they fail the initial screening. And you see things like upgrading, meaning I took a real heavy thick crude oil and I actually partially processed it to improve its viscosity and make it a lighter crude oil that I then sold into the marketplace. So clearly this type of regulation has the potential to, what we would characterize as, decrease the availability of crude oils. Because the refiners would shy away from something like this because using a potential high carbon intensity crude oil would accrue incremental debt, carbon debt so to speak, that would have to be offset.

And, as I explained earlier, the low carbon fuel standard will offer some challenges in the latter year to achieve compliance with known traditional renewable or low carbon fuels today. So that would make it even more difficult. So we believe it’s unlikely that refiners would intentionally use something like this. So in essence you’re precluding a portion of the market. So that can have economic consequences and it can have energy security implications. So we will be looking at that as part of our work and continuing efforts with the Air Resources Board.

MOTEMS are sort of the other catch-all category. It is part of the California Business Code now. This was designed over a long period of time and there is an extensive amount of thought behind it. And the purpose is actually to make the mooring facilities stronger to resist earthquakes and tsunamis, to the extent that there won’t be a leak from the vessel that is moored there. Some of the facilities in California date back to the 1920s and are still in use. A lot of wooden piers. And so those certainly weren't designed initially to hold the size of the vessels that are in some cases, you know, four, five, six, seven, eight times larger than they were when they were initially designed. It's not to imply that they are unsafe, they are safe to be used, obviously. But in the event of a certain sized magnitude earthquake or a certain sized tsunami there is a feeling there can be release.

So this set of building codes has been designed to make modifications and then be much safer or reduce the risk of a release for those kinds of events. The program simply will – there is a stage where you do safety audits in that you have people come out and you determine what needs to be done to modify the facility and have it fully comply. That is being completed for the main terminals that are in two categories of medium or high risk. And those are essentially all the oil and petroleum product terminals in California.

Now we are into the more important stage and that is, who pays? And this is of particular interest in the Port of Los Angeles because they are the port's terminals and then attendants have leases, long-term leases or some month-to-month leases, as the case may be today. And so there is some discussion on, well, do all of them need to be upgraded? Maybe not all of them because, you know, who is paying, how much are you going to pay or are they going to co-share? So part of that debate – the final sub-bullet here – is the Port of Los Angeles and to some extent the Port of Long Beach actually use our forecasts and they cite that in their literature and their letters to the State Lands Commission on what their intent is in not upgrading all of the facilities. So once again we will be doing our assessment, sort of a peak capacity look at this infrastructure. And that will be part of this decision-making process, whether to upgrade or not upgrade certain facilities.

The new ozone standard was proposed in January of last year initially. Seventy-five parts per billion is the standard and the proposal is to look at lowering that to somewhere between 60 and 70 parts per billion. Well, it doesn’t seem like a lot but there is a significant amount of controversy associated with that. And as you note from the chart on the left, there are a number of additional locations that would be out of compliance if the standard were to be lowered as suggested. We don’t know yet what that lowering may be, that is supposed to come out in July of this year. In that timing it may be too late for us to include the final proposed lowering but we will look at that range. And what we essentially look at, I mean, there are myriad programs that air districts would employ to try to reduce the amount of ozone exceedances in their districts that may or may not include fuels. But certainly different fuel reformulations in places like Arizona and Nevada are something that we will pay attention to because there can be supply implications for one, depending on who can make these kinds of stricter standard fuels or more advanced reformulated fuels. And then, more importantly for Arizona, where would that be coming from, the west from California, putting a greater burden on the refining infrastructure here? And/or coming from the east? So we are very interested and we continue to work with people in Arizona and Nevada to understand how they may comply. Because as you can see from the chart there, there are some additional areas in both Nevada and Arizona that would come into play for the newer standards.

Agricultural commodities, I will sort of mention the obvious here. The ramping up of ethanol per the RFS2 mandate and primarily almost solely met with traditional corn-based ethanol at this point in time, but limited as time goes by not to unduly impact the agricultural markets. But you can see here that there has been a rather strong increase in the quantity of corn in the red bars over the most recent years to be used to convert to fuel ethanol. So we expect that to continue and in 2011 for corn to be the dominant use as a percent of all uses to produce fuel as compared to the other categories. So this does have an impact on market-clearing prices. There are many other factors involved in the commodity markets. There was a huge runup in 2008. Certainly that shouldn't be pegged to an increase solely on demand for corn-based ethanol, there are many other factors at play here. But over time, over the long run, this is a significant change in this use.

Now, the amount of corn produced has continued to grow on roughly the same amount of acres because of continued yield improvements. So we are keeping an eye on this because two of the last three years there were some downward revisions to the yield estimates. So the other estimates in the past forecast have continued yield at very significant growth rates. You know, we will have to see what USDA is going to say about that in this next go-round. Because it is very important and germane as to how much acreage one would need and what amount of corn would be available for conversion to fuel ethanol.

Another important source of ethanol under the Low Carbon Fuel Standard is ethanol produced from sugarcane. It has significantly low carbon intensity and we think that is going to have a high demand in California. Well, there is actually an import tariff that is a bit of an economic challenge to use Brazilian ethanol in the United States and in California of course. And there are two forms of the tariff, it is a 54 cent a gallon as well as a 2.5 percent ad valorem on top of that. This has been raised in Congress and will be raised again. We certainly see that as a bit of an economic barrier. The lower prices of ethanol in the United States last year and continuing to this year have been so low in fact that Brazilian ethanol cannot compete in this marketplace with transporting here and paying this import tariff.

There is a portion of ethanol that can be brought into the United States duty free. That’s Caribbean Basin Initiative or CBI ethanol from places like Trinidad and Tobago, El Salvador, Costa Rica. So essentially it is seven percent of our use of ethanol from the previous year. So that’s a rather significant volume. In fact, the most recent calculation, I believe that was conducted near the end of last year, is a volume that is greater than the entire capacity of all of those locations. So we don’t think CBI ethanol will max out that limit. But even if it does it is still not sugarcane based lowest carbon intensity commercial ethanol available. So this is an issue that we plan to discuss again in our staff report and we will see what the debate is outside the state on this issue.

Another is credits. These charts on the left show both renewable identification number credit values for ethanol on the top chart and biodiesel on the lower left chart. And, as you can see, just glancing at them they seem to rising from left to right and rather aggressively, especially in the biodiesel. And this is a source of revenue for those that produce from those biodiesel facilities. They are not obligated parties so it’s an additional revenue stream. Well, is something analogous going to come about in California with the Low Carbon Fuel Standard and their credit trading system? We do expect there will be credits from California biofuel producers, both biodiesel and ethanol. What level of revenue that may have, we don’t know. It’s just a surrogate for what we could expect. Because that’s very important to maybe some incremental revenue for profitability of California bio-refineries. This program is not yet in operation but we hope to have it in operation soon and we will start to see some price discovery along these lines.

The BP oil spill last Spring, the Macondo well, we believe is the largest in world history for an accidental spill, not on purpose. That would be the initial Gulf War, that was an on-purpose spill into the gulf. We are looking at this. A lot of work has come out of this tragedy for both those killed and injured as well as damage to the environment and the economy, the local economy. There have been suggested changes to drilling practices in the Gulf of Mexico. We want to discuss some of those, we want to do what we think is an important comparative to the gulf situation and the California situation. Certainly there is a moratorium off of the coast of California right now. But we want to talk about sort of where there are differences in the drilling environment. Are there differences and, if so, is that relevant? We want to look at the potential resource base information available for both regions.

Gulf of Mexico oil production has been rising. In fact, 2010 oil production in the United States actually reversed a trend of continued decline and actually rebounded, in part because of the Gulf of Mexico activity as well as continued increased production from new types of technology akin to that used for natural gas in shale, used in the Dakotas, part of Wyoming and part of Saskatchewan in the Balkan formation, a very large formation that has seen significant increases in contributions to domestic production. So we expect that to continue and we will talk about that as part of this discussion in the report.

A final element I just want to touch on today that we intend to pursue as part of our staff work is the area of energy security. This can be a whole report in and or itself and has in the past at the Energy Commission been a subject for workshops for this subject alone. But we would like to sort of narrow this discussion in a couple of areas. And it has to do with certain types of fuels that we might have a growing dependence on that may fall under some definition of potential increased energy security concerns, like maybe looking to a fuel that is only available in one or two countries. Another is in the area of crude oil and that may have to do with the Low Carbon Fuel Standard and may be some crude oils being more challenging to use and having to go to other places that may not be as high on the energy security ranking as others.

So we intend to address various aspects of our analysis with some energy security perspective. So you would expect to see that. I think a final element of that is something we call even advanced technologies. One can think of things like lithium batteries that are used are technology that do have, at least at this time, a finite small number of locations where that material can be sourced from. And so it’s another way of doing a more complete assessment of how things are changing over the near and mid term as we do part of our work.

So that concludes my presentation. I would be happy to take any questions from the dais at this time.

VICE-CHAIR BOYD: Gordon, if I might, I have two or three questions. Your slide five, which referenced the reduction in cellulosic biofuels down to six million gallons, can you tell us why this was reduced? Is this a lack of technology available to produce cellulosic biofuels? Or, if there is technology, is it a lack of adequate production capacity or production facilities to provide volumes much above six million? Or is this pure politics, is this pressure from the corn lobby to back off the competition?

MR. SCHREMP: Commissioner Boyd, I don't think it's the final possibility. I think I would have to rule out the politics.

VICE-CHAIR BOYD: Oh, I just wanted to throw that in for fun.

MR. SCHREMP: Certainly the obvious answer and conclusion by the Energy Information Administration, USEIA, who looked at available capacity for cellulosic biofuels and found that, lo and behold, there was a paucity, only five-point-something, six-point-something. And they suggested that really not a lot is coming online. They did think that it's possible in 2012 that there could be a couple of hundred million gallons-plus capacity but there were still challenges.

What those challenges are, why after so many years of money and research and support and even, you know, mandated levels signaled years in advance, clearly there is something else going on with this technology. We don't clearly understand it. We would hope to obtain input from more knowledgeable sources. Is there in fact somewhat of a technology and/or economic bridge that can't be crossed going from the demonstration plant level to the commercial scale? Does it now work when you get – it’s not a scalable technology necessarily. Is there something in there on the technology side that is creating production issues just from an operational perspective and/or much higher economic cost in this environment of very low ethanol prices? These ethanol prices are extremely low because there is essentially a glut of ethanol, which is why the US set a record this year in how much ethanol they exported from this country, primarily to Europe and Canada and even some to South America.

So we’re not sure, Commissioner Boyd, exactly the reason that the capacity expansion has not occurred. But we definitely would seek assistance and input from stakeholders to be put into the record as to why. And most importantly, over the very near term, 2012 and 2013, is that going to hold or not? And if it doesn’t hold what might be a change? For example, does the advanced category take on that entire volume? And we just don’t know the answer to these questions. But we will seek advice from USEPA, USEIA and others to try to get an answer to that question.

But it is a bit disturbing because I know this is not a brand new technology. You know, Commissioner Boyd, this has been around for decades and an extensive amount of effort by many, many people, lots of capital, lots of smart people. So we just don't clearly understand why it's having growing pains continuing to this point in time.

VICE-CHAIR BOYD: Okay, thank you. Well, I'm going to jump to my third question, which builds on this discussion you just engaged in. Your chart 26 had, you know, the red bars and the blue line, the significant increase in ethanol, the significant decrease from corn, the significant decrease in the blue line, which I believe represents one could say almost food in a broad sense. There has been a huge debate about food versus fuel, it's been on again off again, it's been disputed, the RFA disputes it violently almost.

But that chart right there seems to indicate that there is something going on here. Because the amount of corn-based material dedicated to food and fiber is very proportional to the increase in corn-based ethanol that's produced. So that's a comment really. You're free to comment on that but it's not much of a question, it's more of a comment on my part.

MR. SCHREMP: Well, Commissioner Boyd, I would just clarify. That top blue line I guess you could say is indirect food. Feed the animals that we eventually feed upon, cattle and hogs and stuff.

VICE-CHAIR BOYD: Yes, I know.

MR. SCHREMP: But, yes, the cereal aspect is that light green line.

VICE-CHAIR BOYD: Right.

MR. SCHREMP: And that has remained relatively stable, your corn flakes, if you will.

VICE-CHAIR BOYD: Never touch the stuff.

My last question. In your discussion in chart seven of the ten percent blend wall and all the issues associated with higher level blends of ethanol, materials and compatibility, either in vehicles, as you discussed misfueling, or the materials in dispensers, is a true fact and is something that has been discussed a lot. But as you briefly touched upon, there has been quite a debate around the 15 percent ethanol idea and a lot of concern expressed about whether older vehicles can tolerate those higher blends. And lately, I guess, there has been some EPA study showing no – at least one tranche of older vehicles seems to be okay. I think I read something just this morning about, well, maybe the next tranche is okay as well. But there has been continuing talk about concerns, anything above ten percent, and yet 15 percent is being indicated as not that big a problem.

When is this going to get resolved? When might we see 15 percent? Will we ever see 15 percent? Those of us who drive older vehicles, do we really have a problem with that?

MR. SCHREMP: Well, I think, as I mentioned, because of the change in the ownership at retail and the absence of liability protection for those owners from misfueling, that is a big risk for an industry that actually, according to industry data, makes anywhere between thirty-five and forty-five thousand dollars per location per year pretax. So you could imagine that, okay, well I'm going to purvey E15 and hope everyone reads the stickers. Because I'm not going to pay an attendant to stand there and look at their VIN number and say, ah okay, you can use this. There is a risk there.

So if E15 would happen to be a cheaper product to purchase and maybe be potential cents per gallon, even if that were to be the case you weigh that against this risk of liability exposure for misfueling. Now I know there have been efforts to have some sort of blanket immunity, if you will, for the retailers, that if someone comes after them they say, well, no don't come after me, go talk to the government about your claim. If something like that were to happen certainly you would see a largest risk or concern removed from those retailers. And then you might see more E15 come about.

But the automobile manufacturers have sued. And I haven’t seen one of them express desire to modify their warranty language and just issue you a new revised page to put into your warranty book. Like, oh, never mind E15, just change that one page. I haven’t seen any indication that they will do that. So those are pretty big barriers. We think the retail infrastructure compatibility, you can overcome that, continue to work hard on that. I mean, that could be overcome in a couple of years.

But these other issues are pretty big. And that’s why I think you’re seeing some significant pushback at the federal level in the dialog at this point in time. That’s why we don’t think it would be prudent to assume E15 in a couple of years in California in our forecast work. You know, we have to be convinced otherwise why that wouldn’t be a big deal and, yeah, it will happen.

I think a final point on this is the whole reason there was growth of energy, a primary reason they requested this waiver, is because they like others saw that that large 36 billion gallon ratcheting up of RFS2 mandated minimum volumes was going to broach this E10 blend wall. And they go, well, gosh, at least E15 should be no harm, no foul in the vehicles and that should be okay. Quickly do that and then, you know, stave off the point where you go beyond the wall. Because once you go beyond the wall it’s what we showed in our state analysis. Now you've got to go to E85. Then there was, well, we are going to need a much more significant infrastructure nationally to do that. So this was really to stave off when you would reach the blend wall. But even for that sake of argument, going to E15, you still delay the inevitable. You are going to reach the blend wall two or three years later anyway. So it doesn't prevent it over the life of the RFS2 obligation program, you just delay it a couple of years.

CHAIR WEISENMILLER: I had a question on slide 21. Basically back in the late 70s we ran into an issue where as we were getting heavier crude into the California refineries and a greater demand for light products basically we were finding that one of the things that led to the shortages at the pumps was not necessarily the amount of petroleum that we were being ratcheted back but also the shift in the quality. So I'm trying to figure out over time going out into the future, again, this mix of refinery products and demand, what that means in terms of the actual capacity or modifications. You know, how is that system really going to work?

MR. SCHREMP: That's a very good question, Chairman Weisenmiller. In fact, like you said, back then the heavy diet of California crude available to them, the changing demands in the fuel qualities were such that refiners had to expend a great deal of money to handle that difficult crude, both in the higher sulfur content and lower viscosity. So the California refiners, after spending billions, are now probably some of the most sophisticated refineries in the world.

But your other element about the changing mix is spot on. Because we just briefly touched on this in our 2009 IEPR. But what is happening with the decline in gasoline demand because of the factors Malachi mentioned as well as the RFS2 overlay pushing it down further, what's happening to diesel and jet fuel over the same period? Well, they are not declining, they are continuing to grow. So what you have now is refineries cooking the crude oil and what comes out in various proportions is based on the equipment. There is some limited flexibility in how they can modify that.

So simply put you could have a situation where the California refining complex starts to look a lot more like another place on earth, Europe. So what happened in Europe? Because of taxation policies favorable to diesel you saw an increasing demand for diesel, rather aggressive, a flattening of gasoline demand. And now the European refineries are saying, I need diesel, more than I can make and, oh yeah, I have a bunch of gasoline for sale. So what happened in Europe is the United States gasoline demand was continuing to grow. The Northeast of the United States is short on refining capacity, they import two-thirds via pipelines primarily and across the water. So a cargo of diesel – higher demand, higher market clearing prices there, attractive for the United States – went to Europe, emptied that cargo, filled it up with gasoline and components and sent it back. Back and forth, back and forth across the pond. That works well.

All right, extend that analogy to California. So the California refiners will load up that gasoline and send it across the Pacific to, where? They will be competing with whom? The Reliance Refiners of India who doubled the size of the world's largest refinery to 1.6 million barrels per day, essentially as much crude oil as all of the California refiners process. They are an export facility and they sort of set the low cost provider. So if California refiners want to continue operating that is some of their competition. It is an international world for those merchant refiners.

So we believe that that might be a challenge for them. We don't have their production cost numbers. But we look at different things. For example, one of the refiners that publicly shows their quarterly information, shows production costs in various regions, and you see that the California facility has double the production cost of these other regions. Most recently BP's intention to sell some of their refining assets in the United States, and even in their pronouncements as part of that sale, were, well, we are keeping some of our better performing refineries – Indiana, Cherry Point in Washington State – and we are selling BP in Southern California and Texas City.

So that just tells us that they are probably not quite as profitable as those other two facilities that they are hanging onto. So we think that, assuming that they will just continue operating, that the export market will be there and they will be competitive, we don't thing that is realistic. Therefore, that's why this time we are looking at either a contraction and/or lower utilization, whichever way you want to look at it. The result is the same for the crude oil.

CHAIR WEISENMILLER: Thanks.

MR. OLSON: Gordon, I have kind of a follow-up, going back to Malachi's presentation. This transportation report is going to evaluate the petroleum reduction goals, the alternative fuel goals. And to what extent is this report also going to assess – well, I guess, how well are we doing in meeting those goals? But also the Bio-energy Action Plan, the biofuel aspects of that, and the greenhouse gas emission reduction, this so-called transportation fair share. Are you going to cover that as a sum-up in this report?

MR. SCHREMP: Well, I could probably rest assured we won't probably adequately cover all of that. But we would like to get some additional guidance from the dais in exactly what aspects are most important to cover at a minimum. But I think as part of our assessment of demand for renewable fuels moving forward we do intend to look at where they are coming from. We do intend to look at California's production capacity for renewable fuels, existing, idle, what might be under construction or planned to construct. And with that we would go toward, you know, the 20 percent locally sourced biofuel. So we would like to better understand where some of the more important aspects that we should be covering at a minimum as we work through this process with you.

MR. OLSON: Okay, thank you.

MR. SCHREMP: Any other questions or comments from the dais or the audience?

(No response.)

MR. WENG-GUTIERREZ: So just to end the day I just had a slide about next steps. It's basically that we are going to be finalizing the inputs into our model, taking comments from today and comments that we will receive in the comment period, and then finalizing our inputs into our demand forecast. We will be holding, as we mentioned numerous times throughout this workshop in plugging our next workshop, a transportation energy infrastructure workshop in May, May 11th is I think our tentative date. And we hope that people participate in that. Certainly we will be talking about a number of important issues that I think will hopefully address some of people's questions that were raised today.

And then following that we will prepare our draft demand scenarios and import requirement projections for our draft staff report. Then we will hold a third workshop in August and that will be presenting our proposed transportation energy scenario and our results. And then we will finalize our staff report after that and then, of course, work towards providing the information for the IEPR chapter.

So that's the end of the work that I was going to present. Here is a slide of just our contact information. If you did download the presentations earlier today or yesterday, I think, some of the contact information may not have been appropriate. There was a phone number that was a little different. I tried to field some of those questions that might be directed to me to someone else. But I might not be able to do that. This slide has my correct phone number on it and the slides that are online now have the correct number. So with that I think I'm done.

MS. KOROSEC: So we've kind of been taking questions as we've gone along throughout the day but we want to give one last opportunity. If there is anybody here in the room who would like to make any additional public comments, now is your chance.

(No response.)

All right. Anybody on line?

(No response.)

Okay, with that I just want to remind everybody that written comments on today's topics are due by close of business on March 7th.

CHAIR WEISENMILLER: Okay, thank you. This meeting is adjourned.

(Adjourned at 3:55 p.m.)

CERTIFICATE

I certify that the foregoing is a correct transcript from the electronic sound recording of the proceedings in the above-entitled matter.

______________________________ ______________

Michael F. Connolly, CER
Reporter/Transcriber

Date