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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 Bamberg, 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

1  
2 FEBRUARY 24, 2011

9:05 A.M.

3 COMMISSIONER WEISENMILLER: Good morning.

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

11 Suzanne?

12 MS. KOROSSEC: Good morning, everyone. I am Suzanne  
13 Korossec, I manage the Energy Commission's Integrated Energy  
14 Policy Report unit.

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

23 Today's workshop is being broadcast through our  
24 WebEx conferencing system and parties need to be aware that  
25 you are being recorded. The audio recording will be posted

1 on our website within a day or so of the workshop and you  
2 will have a written transcript available within about two  
3 weeks.

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

15           The purpose of today's workshop is to present  
16 staff's proposed analytic methods for the electricity,  
17 natural gas and transportation fuel demand forecasts, to  
18 discuss the modeling inputs and the assumptions about key  
19 demand drivers, and to get input from stakeholders on  
20 staff's proposed methods, inputs and assumptions. Our  
21 analytic efforts are coordinated among several offices,  
22 including our Demand Analysis Office, which forecasts  
23 statewide electricity, natural gas and use demand; the  
24 Electricity Analysis Office's Natural Gas Unit, which does  
25 long-range assessments of state, regional, national and

1 global natural gas demand; and the Fossil Fuels Office,  
2 which assesses transportation fuel demand and transportation  
3 infrastructure needs.

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

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

24 I also want to note that we are accepting written  
25 comments on today's topics and those are due by close of

1 business on March 7th. The notice for today's workshop,  
2 which is available on the table in the foyer and also on our  
3 website, outlines the process for submitting written  
4 comments to the IEPR docket.

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

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

20 MS. KOROSSEC: All right, we will start with Ruben  
21 Tavares.

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

25 This morning Ross Miller, Leon Brathwaite and myself

1 would like to provide you with an update on where we are in  
2 regards to a mandate that you gave us – well, actually your  
3 peers gave us – in the last three IEPR cycles. The mandate  
4 refers to how staff handles natural gas price forecasting in  
5 relation to the model and also the methodology. We will  
6 provide you with a brief history of our forecast and also  
7 EIA's forecast as compared to actual prices in the market.  
8 Then after me, Ross will present a proposal on how to move  
9 forward for your consideration and also for your comments  
10 and inputs. Leon also will give a short description of some  
11 of the key drivers in the natural gas market that we are  
12 paying very close attention to.

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

25           In addition, we also would like to coordinate with

1 the utilities and some of the stakeholders to help us  
2 proceed in the natural gas effort that we will provide for  
3 you in this IEPR cycle.

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

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

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

1 forecast methods in the 2007 IEPR.

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

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

22           So in 2009 staff actually did not use the model to  
23 forecast natural gas prices or any other parameters.  
24 However, we focused in the 2009 IEPR on some of the main  
25 topics that at the time were very important, such as LNG,

1 shale gas, pricing issues that were important at the time,  
2 infrastructure and natural gas storage. But again we did  
3 not forecast any natural gas prices. However, again  
4 commissioners indicated at the time that they were still  
5 concerned about us generating a single price forecast. And  
6 so they directed us again to continue researching our models  
7 and methodologies that we use to do this forecast.

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

19           So how did we do as far as forecast? This graph we  
20 have the forecasts that we have for just three years, 1995,  
21 1998 and 2000, plotted against the actual wellhead prices in  
22 the market. As we can see, we were actually forecasting  
23 very low natural gas prices and the prices in the market  
24 were quite a bit higher than we had forecast. And here are  
25 the assumptions that we had at the time in the model and

1 then this represents only the reference case.

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

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

19           Now, this graph illustrates the forecast that EIA  
20 has done in the past – again, just the reference cases. As  
21 we can see, early in the 1980s EIA was forecasting very high  
22 prices. And again I apologize for some of you that have the  
23 black and white presentations, it is hard to see it. But  
24 here I think you can see how prices vary all over the place.  
25 EIA for a while now has been generating different scenarios

1 and different sensitivities around the reference case. In  
2 the latest, actually the 2010, forecast they have 35  
3 different scenarios where they assume either that we will  
4 have no shale production for the next 30 years to another  
5 one that we will have some shale gas production. So this is  
6 the record up to 2004.

7           Some of the assumptions in the 2000s that EIA had  
8 made, they were at one point seeing the decline of domestic  
9 production. And so a big increase in Canadian natural gas  
10 and LNG. Again at one point they predicted the Alaskan  
11 pipeline would be built by 2016. They saw strong demand for  
12 gas for power generation. Rocky Mountain production will be  
13 increasing in the lower 48. McKenzie Delta pipeline,  
14 actually, they saw the McKenzie Delta to open by 2010 and I  
15 don't think that's going to happen. I mean, it is already  
16 2011.

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

24           SO what is the record for EIA versus annual average  
25 wellhead prices? Well, we can see they have – this slide

1 represents prices from 2005 to 2010. High prices in nominal  
2 terms. So we have up to 2010 here and I think I have  
3 another graph – well, I will present the other graph in a  
4 minute here.

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

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

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

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

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

12           I wanted to make one correction on this graph. We  
13 don't have the actual prices because this starts in 2010.  
14 So this shows the two plots of the forecast in 2010 and  
15 2011. As we can see, EIA in a few months has actually  
16 decreased the forecast, predicting lower natural gas prices  
17 for the next 20 years or so.

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

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

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

22           So how would we would actually like to move forward?  
23 Again, staff in conjunction with consultants has at this  
24 point thoroughly reviewed the methodology and models that we  
25 have used in the past to forecast the natural gas

1 parameters. And we – again, in conjunction with management  
2 and some consultants – have presented this to some of you.  
3 We have concluded that the MarketBuilder platform that we  
4 have used in the past to build up the natural gas model was  
5 the appropriate tool, or was the best tool at this point to  
6 continue. We also concluded that the best way to proceed  
7 for the IEPR cycle is to use somebody else’s model that has  
8 been already built and that can be modified for our own use.  
9 And that will be the model of the Energy Institute at Rice  
10 University.

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

12 Good morning, Commissioner. Good to see you.

13 VICE-CHAIR BOYD: Good morning.

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

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

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

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

3 MR. TAVARES: Sure.

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

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

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

19 MR. TAVARES: Yes.

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

23 MR. TAVARES: Correct.

24 CHAIR WEISENMILLER: And one of the data points I  
25 want to really verify, that input assumption, is what the

1 industry is saying their shale gas production is going to  
2 be.

3 MR. TAVARES: Okay.

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

15 MR. TAVARES: My understanding – again, I wasn't in  
16 the unit at the time – but my understanding is that in the  
17 2005 IEPR cycle we combined both the futures and also our  
18 own conventional gas, you know, to generate a forecast that  
19 the commission adopted. Is that correct, Leon?

20 MR. BRATHWAITE: Basically, yes.

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

24 CHAIR WEISENMILLER: Okay. But one of the other  
25 pieces of data I want to see is what the futures look like

1 on this. Again, when people are making major investments  
2 they tend to look at that as part of the data. So again, I  
3 think we need to have that sort of information developed  
4 too.

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

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

11 MR. TAVARES: Yes.

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

15 MR. TAVARES: Okay, we will do that.

16 CHAIR WEISENMILLER: Okay, thanks.

17 VICE-CHAIR BOYD: I've been away from the Natural  
18 Gas and Electricity Committee for a little while now but  
19 lived through with you and other staff some of these debates  
20 about point forecasts and what have you. But moving over  
21 the shale gas subject, I think the Chairman's point is an  
22 excellent one. I have been troubled for some time about the  
23 shale gas estimates that had been made only in that I think  
24 they are incredibly optimistic - this is just me speaking -  
25 in terms of what will ultimately be realized. And I think

1 what the industry is forecasting the potential is is  
2 definitely a point we need to know. And I think your source  
3 document is an excellent place to go.

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

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

19 MR. TAVARES: And -

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

23 MR. TAVARES: Uh-huh.

24 CHAIR WEISENMILLER: And certainly trying to pull  
25 in some of the recent MIT study I think will help us too,

1 along with the industry.

2 MR. TAVARES: Absolutely.

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

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

11 MR. TAVARES: Okay, thank you, Commissioners.

12 CHAIR WEISENMILLER: Thank you.

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

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

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

25 We also support the use of futures. Futures are

1 becoming more prevalent and, as you said, Commissioner, the  
2 industry locks in futures prices and even though prices may  
3 decline if they are locked in they will continue to produce.

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

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

20 Also you have the Ruby pipeline which will bring gas  
21 to California. And, as you know, our parent company Sempra  
22 Energy was a participant in the Rockies Express Line to take  
23 gas from the Rockies to the east. And lo and behold a few  
24 years from now it may be that that pipeline has to be  
25 reversed to bring shale gas to the west because there is

1 going to be an overabundance of shale in the east. Alaska  
2 does not look like it's a possibility anymore because of  
3 these low prices and the heavy government supports.

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

10 CHAIR WEISENMILLER: Thanks, Herb.

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

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

1 uncertainties?

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

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

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

17 CHAIR WEISENMILLER: Okay.

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

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

23 MR. EMMRICH: On the base gas price forecast we use  
24 futures and we use all the other industry forecasts from  
25 EIA, from the Energy Commission and from private sector

1 companies like Wood McKenzie and so on. And we do a  
2 weighted average of those forecasts for our base.

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

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

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

9 MR. EMMRICH: No, we look at NYMEX.

10 CHAIR WEISENMILLER: Okay.

11 MR. EMMRICH: Thank you.

12 CHAIR WEISENMILLER: Thank you. Go ahead.

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

18 MR. EMMRICH: That's a very painful question. Of  
19 course, like everybody else in the industry five years ago  
20 we were thinking we were running out of gas and we have over  
21 six-million gas customers in Southern California. So to  
22 safeguard that the parent company built an LNG facility in  
23 Baja California. That facility is used very sparingly  
24 because, as Ruben pointed out, internationally LNG is priced  
25 according to oil prices. So in Japan LNG is nine or ten

1 dollars a million BTUs, in Korea and so on. Whereas, the  
2 border price now is four dollars. So we are not attracting  
3 very many cargoes. Random cargoes looking for a home will  
4 land there and we also have a complex with the Mexican  
5 electricity department. So some gas has to be delivered  
6 there and it is and they are buying that.

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

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

20           MR. EMMRICH: Well, in the US there seems to be a  
21 total disconnect with oil prices because there is so much  
22 gas-on-gas competition and more gas coming online. So the  
23 thing that may change that is gas-to-liquids projects. In  
24 other words, you can make diesel, high quality diesel, out  
25 of natural gas. And that would be cost effective at this

1 point. I'm kind of surprised that the oil companies and the  
2 gas producers are not looking at that.

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

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

9 SENIOR POLICY ANALYST BROWN: Right.

10 MR. EMMRICH: And certainly that is cost effective.

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

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

24 A quick question about renewable natural gas, which  
25 has been something of great interest the last - well, the

1 last year if not longer. A new term, we used to call it  
2 Biogas, but now renewable natural gas seems to have finally  
3 stuck as going to be the formal term. Does your company see  
4 much activity in that arena in the near term?

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

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

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

1 in that case.

2 MR. EMMRICH: Right.

3 VICE-CHAIR BOYD: Okay, thank you.

4 MR. TAVARES: Any other questions or comments?

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

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

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

22 MR. BAMBURG: During the majority of 2010, starting  
23 with March - because the Tangguh facility was delayed in its  
24 startup but once it was kind of fully up and functioning -  
25 we've been receiving cargos for the majority of 2010, you

1 know, roughly every 12 days.

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

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

11 CHAIR WEISENMILLER: That would be good.

12 MR. BAMBURG: Okay.

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

18 MR. COX: Good morning. My name is Rory Cox from  
19 Pacific Environment. This issue of LNG exports, I don't  
20 think, is one that should be underestimated in terms of an  
21 input that could really impact natural gas prices. When you  
22 look at what's going on with the Kitimat facility in British  
23 Columbia, Sabine Pass in Texas, and talk of other LNG  
24 projects that were ostensibly built to import, now talking  
25 about flipping to export. When Japan is paying 12 dollars

1 per unit for natural gas and we're paying four dollars and  
2 you are a natural gas producer, obviously you are going to  
3 sell to Japan. So I think that could have a big upward  
4 impact on our natural gas prices here in order to compete  
5 with that world market.

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

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

12 (No response.)

13 Anybody on the internet?

14 (No response.)

15 Okay, thank you very much.

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

21 I have just eight slides and we've already actually  
22 talked about the contents of a number of them. I also have  
23 a handout, which is a chart. And it's essentially a picture  
24 of slides five, six and seven. Or slides five, six and  
25 seven are a description of this chart. Either way they go

1 together. I'm not going to try to show that chart on the  
2 screen, it's just too small.

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

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

20 The workshop is noticed for demand forecasting.  
21 When we're talking about the demand for natural gas we have  
22 to think about both the end use gas demand, the end use  
23 electricity generation demand, because that is served by gas  
24 as a marginal resource. And because burning gas in  
25 generators is a marginal resource for generation we also

1 have to consider all of the alternate electricity supply  
2 options that might displace gas as the generating fuel. So  
3 it just adds another level of complexity to what we are  
4 trying to achieve here.

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

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

22           Essentially what it is, it's the price that would  
23 have to be sustained to make all the investments that the  
24 model chose to make with its internal logic thinking that  
25 they are economic under all the conditions that you assumed

1 in that particular run. And there are thousands of  
2 assumptions that we have to make about future conditions of  
3 the drivers of gas demand, supply and resulting price. And  
4 they are all complex and interacting. So it is quite a  
5 challenge. So I think Herb got it right when he said it is  
6 very difficult to do.

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

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

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

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

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

1 selected these cases.

2           It's basically a bounding analysis. The challenge  
3 is to build up the assumptions about the real world future  
4 conditions that are plausible, not wildly high or wildly  
5 low, but plausible individually and also in combination.  
6 And that's part of the area where, through the comments here  
7 today and especially written comments - I guess due March  
8 7th - any help with that will be greatly appreciated.

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

21           Part two is, there is a lot going on in California  
22 that would affect the demand for gas. And through whatever  
23 price you assume our exposure to cost of gas. Not only that  
24 but the flows, whether the infrastructure is adequate, and  
25 other impacts of the natural gas system demand and use. One

1 might be the emissions, climate change emissions. So these  
2 cases will focus on what is going on in California that  
3 drives demand for gas and our exposure to cost and those  
4 other performance indicators.

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

16           So we will have that feature turned on when we  
17 create these cases. Because that is basically the way  
18 people decide whether or not to build these pipelines. And  
19 a lot of the conditions, some of those many thousand  
20 assumptions would be average temperatures, average rainfall,  
21 which affects hydroelectric generation, which affects the  
22 amount of gas generation you need, which affects gas demand.  
23 Those will be under average assumptions. But then we need  
24 to do sensitivities on those systems because at any given  
25 year you can experience situations that are more stressful

1 to the system that you wouldn't assume when you are deciding  
2 whether to invest in the infrastructure. Nevertheless, you  
3 still have to suffer through them when they happen. So we  
4 will do sensitivity cases that stress the temperature,  
5 hydroelectric conditions and possibly even economic  
6 conditions.

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

21           The other one is to look at the either long-term  
22 infrastructure planning and market impacts of widespread  
23 pipeline integrity issues. So this also would be subject to  
24 availability of data on pipeline integrity. Pressure is not  
25 something that is simulated in this model. We would have to

1 go from pressure reduction to capacity reduction. And we  
2 need to understand how segments of pipeline in the world  
3 that might be constrained are represented in the model if  
4 there is a one-to-one relationship, if it makes any sense to  
5 do this. So we are kind of in an early stage of exploring  
6 doing these cases. It should be seen as just a broad brush  
7 approach. As I said earlier, it is not any attempt to look  
8 closely at operations of the pipeline system under varying  
9 conditions of pressure or outages for repair, replacement or  
10 pipelines.

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

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

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

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

24           CHAIR WEISENMILLER: So in terms of questions, I  
25 want to make sure that we do have a base case or reference

1 case that we can use along with the sensitivities coming out  
2 of this.

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

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

1 MR. MILLER: Right.

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

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

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

25 MR. MILLER: Right. When we are doing the

1 assumption selection or assumption building, I call it, we  
2 will be taking all of this into account that we can. I  
3 think that requires - well, I am a biologist, not a  
4 mathematician so I won't give you my understanding of the  
5 Central Limit Theorem. But I think it might be independent  
6 variables with random distributions and all the same  
7 distribution. And I don't think that's what we have in the  
8 gas and electricity markets.

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

16           CHAIR WEISENMILLER: Great. Thanks.

17           MR. MILLER: So just to finish up here, the  
18 approach here is to moderate the risks of the decision-  
19 making using a particular number for a particular purpose.  
20 So the best way to do that is to understand the ranges of  
21 the forecast and what the consequences of those decisions  
22 might be. And so that sets the job at basically prudently  
23 selecting the forecast that gives you that performance. So  
24 basically what Herb was saying when he said coming up with a  
25 robust policy, it may not be optimum under every condition

1 but you basically can tolerate the results under a wide  
2 variety of future conditions that you can't either predict  
3 or control.

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

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

15 MR. MILLER: Certainly.

16 CHAIR WEISENMILLER: Thanks.

17 MR. MILLER: So if there are any questions.

18 CHAIR WEISENMILLER: I covered mine already.

19 MR. MILLER: Okay. From the audience?

20 (No response.)

21 Uniform universal agreement?

22 (Laughter.)

23 There we go.

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

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

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

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

25           CHAIR WEISENMILLER:    But, Rich, the basic question

1 is what percentage odds would you give for that?

2 MR. FERGUSON: Personally? Slim and none.

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

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

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

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

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

25 MR. FERGUSON: No, I missed that one.

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

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

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

20           CHAIR WEISENMILLER:    Okay, thank you.

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

24           MR. EMMRICH:    Elasticity is 0.1.

25           CHAIR WEISENMILLER:    Okay, 0.1.  I don't know if

1 that is consistent or inconsistent, say, with PG&E.

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

6 CHAIR WEISENMILLER: Okay, thanks, Herb.

7 MR. MILLER: I would make one last reference to the  
8 chart. In the center of it is a commercial for our April  
9 19th workshop, where all will be revealed including the  
10 price elasticities that are in the world gas trade model  
11 that Ken Medlock has developed.

12 Any questions online?

13 (No response.)

14 Okay, thank you.

15 MR. BRATHWAITE: Commissioners, good morning.

16 Susan. I hope everybody is doing well. I am Leon  
17 Brathwaite. I work in the Electricity Analysis Office.

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

25 The World Gas Trade Model we have been using for

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

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

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

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

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

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

1 Ruben mentioned.

2 He developed four general functional forms with  
3 independent variables. In the residential sector we have  
4 weather, population, natural gas price, income and heating  
5 oil price. In the commercial sector we have weather,  
6 population, income, natural gas price and also heating oil  
7 price. In the industrial sector we have industrial  
8 production, weather and natural gas price. And in the power  
9 generation sector we have total electricity generation,  
10 weather, natural gas price, fuel oil price, renewable  
11 electricity generation and coal price.

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

20 Another key driver is gas substitutes. In some  
21 areas of the world, in some areas of the lower 48, we have  
22 oil competing with natural gas and that is represented in  
23 the model through some cross-price elasticity. Also we may  
24 have some backstop in the sense that we may have some new  
25 technology that is available that may come on dependent on

1 the price that is generated within the model. So those  
2 things are also represented in that form.

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

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

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

1 the economic feasibility of that project.

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

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

21 But anyway, these are the key drivers within the  
22 World Gas Trade Model, these are the main drivers. There  
23 are others but they are not as important as these. On April  
24 19th we plan to show all our inputs, all our results, all  
25 the things that affect the modeling and all the things that

1 go into producing the price tracks that we will develop.  
2 Both price tracks and all the demand outputs and all supply  
3 outputs, all of these things will be represented in our  
4 April 19th workshop.

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

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

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

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

18 MR. BRATHWAITE: Right.

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

25 MR. BRATHWAITE: The model is regionally divided

1 up. California is a separate region, Nevada is a separate  
2 region, and so on. So there are specific economic,  
3 demographic information for each of those particular  
4 regions. So in California, as you correctly mentioned,  
5 commissioner, right now our economic situation is somewhat  
6 weak, for want of a better word. And to the extent that  
7 that will affect natural gas demand, that will be reflected  
8 in our demand inputs.

9 CHAIR WEISENMILLER: Okay.

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

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

14 MR. BRATHWAITE: Yes.

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

18 MR. BRATHWAITE: Yes.

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

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

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

5 MR. BRATHWAITE: Yes.

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

8 MR. BRATHWAITE: Yes, that's correct.

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

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

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

25 MR. BRATHWAITE: Absolutely.

1 CHAIR WEISENMILLER: Okay.

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

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

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

16 CHAIR WEISENMILLER: Okay, thanks.

17 MR. BRATHWAITE: Questions, comments?

18 (No response.)

19 Thank you very much.

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

1 CHAIR WEISENMILLER: Okay, thank you.

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

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

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

25 Primary uses of our forecast: the CPUC's long-term

1 procurement process, Cal ISO transmission and capacity  
2 studies. In this IEPR cycle it's also going to be input  
3 into an infrastructure assessment that staff is going to be  
4 doing for this cycle.

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

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

24           For example, at that workshop we talked about  
25 changing California demographics. We have a population

1 that's both getting older in terms of the percentage of  
2 households with members above 55 years old, as well as  
3 younger, an increase in those 35 and under. And that has  
4 ramifications, for example, that may lead to reduced average  
5 household size, more condos, smaller homes. And that will  
6 have implications for our energy forecast.

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

21           Going beyond our traditional measures of consumer  
22 purchasing power, we typically use per capita income. There  
23 are other measures that may be useful in energy modeling,  
24 for example, average consumer debt or average consumer  
25 wealth. Or we may want to try not just per capita income

1 but variables that get at income distribution, like median  
2 income versus per capita income.

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

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

24           In addition to that, for our incremental uncommitted  
25 efficiency analysis we will also have three scenarios, as we

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

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

19           Before I get more specific about defining this range  
20 I just wanted to give a brief description of the way we  
21 forecast at the commission. We have individual sector  
22 models for the various sectors. Residential and commercial  
23 is where we use full end use models. Also in the last IEPR  
24 cycle we developed econometric models for these sectors.  
25 And our goal here, what we are trying to do when we

1 forecast, is look at things from both a low resolution point  
2 of view with an end use model and a higher resolution point  
3 of view, a more aggregate econometric model. And hopefully  
4 we gain insights from using both that we wouldn't get from  
5 just using one. And at some point if there is a big  
6 difference between the results from the two different types  
7 of models, there will be attempts to reconcile the two. And  
8 how that reconciliation is going to work, I don't know yet.  
9 This is the first time we're trying this two different model  
10 systems.

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

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

1 (Laughter.)

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

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

19 Okay, so nine scenarios to choose from. The first  
20 six come from Moody's, economy.com. They have their most  
21 likely case, they have a more optimistic case with a  
22 stronger rebound out of the recession, no further decline in  
23 housing prices. More pessimistic cases, a slower recovery.  
24 In S3 we go back into a recession, we don't recover  
25 completely and go back into a downturn. Then there are two

1 scenarios that reflect lower growth in the long-term, S4 and  
2 S5. And they have one that they call fiscal crisis, which  
3 means that we don't get the federal deficit under control,  
4 the dollar crashes, interest rates go way up, and so on,  
5 which is a drag on the economy.

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

11 And here is what these scenarios look like. Here is  
12 a good example of a graph with too much information on it.  
13 But what I want to show here is the spread between the high  
14 and the low for these key econ-demo variables. So in the  
15 case of personal income the spread between the high and the  
16 low is nine percent. For employment it is six percent by  
17 2022. And when we get to manufacturing here we see that  
18 there is a big difference in the feeling about our  
19 manufacturing future in California between Global Insight  
20 and Moody's. The top three lines there are all Global  
21 Insight, so they are much more optimistic about our  
22 manufacturing future than is Moody's.

23 And in the January 19th workshop we talked a lot  
24 about the impact of the downturn in construction. One of  
25 the main reasons why we have such a high unemployment rate

1 is we've lost so many construction jobs. So in terms of  
2 that we also see that the two companies kind of diverge in  
3 their view. Again, all of Global Insight's three cases are  
4 well above the Moody's cases. So they are more optimistic  
5 about a return in construction employment. It almost looks  
6 like for Global Insight we are going to have another housing  
7 boom. And I asked them about it and they said, no, this is  
8 coming mainly from a resurgence in commercial development.

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

18           And here is what these look like by themselves.  
19 First, for personal income and then for employment. What I  
20 am basically doing is choosing the scenarios that give us  
21 the biggest spread in the long run by the end of the  
22 forecast period. And that's what these three do. Our  
23 forecast is a long-term forecast, that's mainly what we are  
24 interested in. So I'm looking for differences by the end of  
25 the forecast period. Some of these other scenarios differ

1 more in the short run but by the time you get to the end of  
2 the forecast period you are almost back to the base case.  
3 Although for manufacturing output you don't get a spread on  
4 the low side, although you get quite a large one on the high  
5 side.

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

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

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

24           CHAIR WEISENMILLER: And how about the high and  
25 lows, do they seem too high or too low or just about right

1 given the range?

2 MR. EMMRICH: They seem very reasonable.

3 CHAIR WEISENMILLER: Okay.

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

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

9 MR. EMMRICH: Thank you.

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

21 I have to disagree with Herb a little bit. We are  
22 not that big of a fan of IHS Global Insights for their  
23 regional forecast. I think they tend to be a little bit out  
24 of touch with the California economy and that they tend to  
25 be focused more on the national and international economic

1 modeling. But in terms of the spread on the three scenarios  
2 that Chris was proposing here, it seems like a reasonable  
3 spread. So that is my take on that.

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

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

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

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

20 CHAIR WEISENMILLER: Right.

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

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

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

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

19 MR. ASLIN: Yes.

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

24 MR. ASLIN: You're really putting me on the spot  
25 there. Moody's has one that they call the expected but I am

1 not sure that ultimately we will be choosing that one.

2 MR. KAVALEC: Okay.

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

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

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

7 MR. KAVALEC: All right. Okay.

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

20 And the other interesting thing that you did note  
21 was the incredible disparity on California as a  
22 manufacturing base in the future. Of course, our friends at  
23 the Chamber and CMTA were aghast, alarmed and in violent  
24 disagreement with the consensus of all of the economists, it  
25 seemed to me, that we are moving away as a state from

1 manufacturing, we are the innovators and beta testers but  
2 not the manufacturers of things. And that will have a big  
3 impact on our future if indeed that comes true. But  
4 geopolitics tends to trump everything these days so it's a  
5 little hard to deal with it.

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

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

12           Any other questions?

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

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

24           So I don't know what can be done to move that  
25 forward. It is always about customer confidentiality that

1 we as the utility are restricted to in giving up individual  
2 customer's end use data and so on. But that would help us a  
3 lot if we get those surveys completed.

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

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

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

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

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

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

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

15           MR. EMMRICH:    I appreciate that.

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

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

1 sort of in-house talking about which should be the base one  
2 and which should be high and low.

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

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

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

21 CHAIR WEISENMILLER: Okay.

22 MR. KVALEC: Any questions online?

23 (No response.)

24 Okay, so then I will proceed with my second  
25 presentation here, the other assumptions that I propose to

1 develop these scenarios.

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

11           The first one, it says "Bentek/Low Case", it is sort  
12 of Bentek and then my adjustment to the Bentek forecast. I  
13 will explain that in a minute. And three EIA cases, what  
14 they call their High Shale Case, which means a lot more new  
15 wells opening up compared to their reference case. Then  
16 their reference case. And what they call their No Shale  
17 Case, no additional wells being opened up after 2010. And  
18 then just because I thought there should be a real high  
19 price scenario I developed this return to 2008 case where  
20 prices are the same as in scenario four through 2012 and  
21 then they creep back up to the relatively high 2008 rates by  
22 2020.

23           And here is what they look like on a graph. You can  
24 see that most of them are bunched up there between four  
25 dollars and six dollars by 2022, except for the real high

1 case. That lowest case there, Bentek Low, their forecast  
2 was lower than any of the EIA cases though 2012 but then  
3 went back up and was the same as the EIA reference case  
4 after that. So what I did was to take the reduction that  
5 Bentek predicts through 2012 and then hold the price at that  
6 level through 2022, that's the low case. And you will  
7 notice there isn't anything here from the California Gas  
8 Report. And that's because, number one, it's a little dated  
9 but, number two, percentage-wise the increase that they  
10 predicted is almost identical to the EIA No Shale Case. So  
11 I didn't put both of them in there.

12 Out of these five scenarios we propose to use these  
13 for the low, mid and high cases. For the low case, the  
14 Bentek Low Case, the one that goes down the lowest by 2012  
15 and then stays flat after that. In total that means a ten  
16 percent reduction on average in natural gas rates between  
17 2010 and 2022. Then in the mid rates I propose the EIA  
18 reference case, which is almost 25 percent higher in 2022  
19 versus 2010. And then for the high rates, the EIA no  
20 further wells, No Shale Case, and that leaves rates around  
21 35 percent higher in 2022 versus 2010. Although I could be  
22 persuaded to use the very highest case, the return to 2008  
23 rates, because of the variability in natural gas rates we've  
24 seen in the past. Anyway, this is my proposal for you to  
25 comment on.

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

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

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

23           So using this tool, I created the following six  
24 scenarios and these vary. We're looking at these from low  
25 to high, three here and three on the next slide. These vary

1 in the sense of lower to higher natural gas rates, current  
2 efficiency levels all the way up to the high CPUC goals for  
3 efficiency. Current levels of rooftop photovoltaic all the  
4 way up to the goal of 3000 megawatts by 2020 installed.  
5 Current levels of renewables up to the 33 percent RPS being  
6 met by 2020. All of these have impacts on prices. And in  
7 the two highest cases, S5 and S6, they assume a cap and  
8 trade system where the price of CO2 is 30 dollars a ton.

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

14           So I propose - again, I'm not wedded to these but  
15 these seemed like reasonable scenarios for our forecast in  
16 terms of low, mid and high. For the lowest case that  
17 involves the current level of efficiency only, the lowest  
18 natural gas rates and so on. That yields one percent lower  
19 rate on average. By the way, what we've been talking about  
20 here so far is average statewide rates, an average over all  
21 the utilities in the state. So low case gives you basically  
22 flat rates in 2022 versus 2009. The mid case assumes the  
23 mid CPUC goals for efficiency, which is what they are  
24 currently using for their procurement, and the EIA reference  
25 natural gas rates. And that gives you a little bit less

1 than 10 percent higher rates in 2022 versus 2009 on a  
2 statewide average. And in the high case we have the highest  
3 CPUC goals for efficiency and the second highest natural gas  
4 rates, almost 30 percent increase on a statewide average  
5 between 2009 and 2022.

6 And here's what these look like by themselves. You  
7 will notice in the S3 and S5 the mid and the low case.  
8 There is a decline between 2009 and 2012 and that's a  
9 function of the way the E3 calculator works. Its first  
10 forecast year is 2012. And then the less aggressive policy  
11 case is it actually predicts rate reductions in 2012 versus  
12 2008. And I don't know how realistic that is, I would like  
13 to hear the utilities comment on that. But an alternative  
14 if we don't think this decline is realistic is just to  
15 straight line it from 2009 or 2010 to the end point in 2022.

16 Okay, as I said these rates we've been talking about  
17 have been statewide averages. The E3 calculator also  
18 predicts rate increases at the utility level for the five  
19 major utilities shown here. Here I'm showing one example  
20 for scenario S5 or our high scenario for rates. But this is  
21 representative of what happens in the calculator for the  
22 other scenarios, too. So costs for individual utilities or  
23 rate increases for individual utilities are based on  
24 assumptions about how they procure their electricity, where  
25 they are in terms of renewable percentages and so on. So in

1 this case we see PG&E a little bit higher in percentage  
2 terms versus the state average, San Diego about the same as  
3 the state average, Edison and SMUD a little bit lower. And  
4 the most striking thing we see here is the very large  
5 increase for LADWP and that comes from the assumption of the  
6 cost of procurement for LA going up sharply with the  
7 expiration of their current contracts for procurement and  
8 because they are lower than the other utilities in terms of  
9 percentage renewables currently. So they have more to make  
10 up. So I would like to hear particularly from LADWP on what  
11 they think of this result.

12           Okay, in terms of efficiency, again I propose a  
13 high, mid and a low. High efficiency going for the low  
14 demand case and vice versa. For high efficiency savings I  
15 propose using the utility savings are reported. The mid  
16 efficiency case would be the same thing as we did in the  
17 2009 IEPR. We took the utility reported savings and  
18 adjusted downwards using what we call a realization rate.  
19 And in a low case this would be applying the CPUC Energy  
20 Measurement and Verification results for 2006 through 2009.  
21 They found that realized savings were much lower than  
22 reported and lower than what we had in terms of an  
23 adjustment downward than what we had assumed in the 2009  
24 IEPR forecast. So this would mean the largest adjustment to  
25 utility reported savings and that would be the low case.

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

4 For the uncommitted efficiency part, the incremental  
5 uncommitted efficiency, we need to rely on the work from the  
6 2009 IEPR since there has not yet been a new goals study to  
7 work with for efficiency. We will do this for the three  
8 IOUs, as I mentioned, plus this time including LADWP and  
9 SMUD. And as you move through time sometimes what was  
10 previously considered uncommitted becomes committed. And in  
11 this case a 2010 Title 24 update that hadn't been finalized  
12 at the time of the last IEPR was uncommitted and will not  
13 become committed. And the Huffman Bill for lighting,  
14 because it has been integrated into the Title 20 standards,  
15 goes from uncommitted to committed in this forecast. So all  
16 else equal we are going to have more committed savings and  
17 less uncommitted savings in our forecast.

18 For rooftop photovoltaic we've developed a  
19 predictive model for the residential sector and that will  
20 automatically give us three scenarios because the predictive  
21 model depends on average household income and average rates.  
22 And if those two things are varying in the scenarios then  
23 the results from the predictive model are going to vary.  
24 And for CHP, again we are sort of at the edge of my  
25 expertise in terms of what to assume for CHP going forward,

1 meaning the amount of power consumed onsite rather than sold  
2 back to the grid. So I will rely on stakeholders here for  
3 comments. But also there is going to be a staff workshop on  
4 March 8th dealing with RPS and there should be discussion  
5 there about what to assume for additional CHP going forward.  
6 So I will be looking to that discussion as well.

7 And that concludes my second presentation. Any  
8 questions?

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

17 I think in terms of looking at your electricity rate  
18 approach, I certainly like the idea of relying on E3.  
19 Again, I think in this era of limits it's good if we can  
20 sort of be sharing, building off of what the other agencies  
21 are doing, making the appropriate adjustments as opposed to,  
22 say, developing our own model there. Certainly I think it  
23 looks like you have some degree of checking the assumptions  
24 that are in the LTP scoping motor as you're constructing  
25 these. And, again, for those scenarios consistency is some

1 virtue there, although I would point out that certainly  
2 Governor Brown's calls for DGU much higher than within those  
3 documents and we need to consider his goals.

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

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

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

25           CHAIR WEISENMILLER: Sure.

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

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

6 MR. EMMRICH: That's from last year.

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

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

16 MR. KAVALEC: Right.

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

19 As far as energy efficiency, you know, it's always a  
20 contentious issue on how you calculate the ongoing and the  
21 naturally occurring. The utilities, of course, spend a lot  
22 of time and effort in order to promote energy efficiency,  
23 that's sort of our life blood at this point. We don't go  
24 market additional gas uses, we go out and market additional  
25 energy efficiency programs. And we want to make sure that

1 there is a proper reflection of our efforts, which is  
2 certainly leading the country in that area.

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

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

16 MR. ASLIN: Okay, thank you.

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

21 MR. KAVALEC: Yes.

22 MR. ASLIN: Right. So if we translate that into  
23 nominal changes they are quite a bit higher. So the one  
24 percent increase in real in the low scenario actually  
25 translates into a nominal increase of - what would you say,

1 Chris, 25 percent? Or something? Inflation is about 2.5  
2 percent on average.

3 MR. KAVALEC: Right.

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

6 MR. KAVALEC: Or more, yeah.

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

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

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

19 MR. ASLIN: Uh-huh.

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

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

24 MR. TOTH: Hi. I'm Phil Toth with Southern  
25 California Edison. Chris, a very good presentation. I have

1 some inquiries about page 15, small page 15, and it has to  
2 do with energy efficiency program scenarios. And just  
3 thinking through recent history, adjustments to EE have been  
4 made about some of the components within the total market  
5 growth goals, most recently in LTPP process where they are  
6 adjusting the Big Bold EE strategies. And in past  
7 conversations we've talked about whether we should include  
8 Big Bold in there or should we not.

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

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

19           MR. TOTH: That's my understanding.

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

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

25           MR. KAVALEC: Yes. It's basically the same as we

1 did last time, the policy driven high, mid and low, with the  
2 exception that I just mentioned.

3 MR. TOTH: Okay.

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

6 MR. TOTH: Thank you, Chris.

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

9 (No response.)

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

12 MR. KAVALEC: I will.

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

16 MR. KAVALEC: Okay.

17 Any questions on the internet?

18 (No response.)

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

23 NRDC has over 124,000 members here in California and  
24 a strong interest in reducing the environmental impacts of  
25 our energy consumption. NRDC is concerned with how energy

1 efficiency is accounted for in the demand forecast. We  
2 commend the CEC for setting up the demand analysis working  
3 group and commend the CEC staff for making themselves  
4 accessible in holding discussions on how energy efficiency  
5 is treated.

6           However, the demand forecast has significant  
7 shortcomings in determining where the energy savings are  
8 coming from. Previously the CEC produced representations of  
9 energy efficiency with about 50 percent of the energy  
10 efficiency being attributed to codes and standards and about  
11 50 percent being attributed to utility programs. This is  
12 commensurate with how our neighbors in the Pacific Northwest  
13 estimate energy efficiency, it's commensurate with how the  
14 PUC evaluated savings historically, and it was presented in  
15 the 2005 Energy Action Plan, too. It was also presented in  
16 the 2003 IEPR cycle.

17           However, in 2009 an alternate graph was produced  
18 which drastically reduced the amount of efficiency  
19 attributed to utility programs. It reduced it approximately  
20 75 percent. This drastic reduction in attributing savings  
21 to utility programs is not commensurate with how other  
22 regions estimate efficiency. Furthermore, it undermines our  
23 ability to get the efficiency savings from utility programs  
24 going forward if the savings are represented as so small.  
25 The demand forecast is designed to produce forecasting

1 results and therefore needs to incorporate the total amount  
2 of energy efficiency but is not designed well to determine  
3 where the savings are coming from.

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

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

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

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

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

24           So anyway, we are aware of this issue and we are  
25 talking to the NRDC in the DA group meetings about this and

1 we are trying to work out a solution.

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

10 CHAIR WEISENMILLER: Okay, thank you.

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

13 MS. KOROSSEC: Let's try to have everybody back here  
14 by 1:00. Thank you.

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

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

California Reporting, LLC  
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1 1:05 P.M.

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

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

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

22 As many of the speakers this morning mentioned, the  
23 Energy Commission has some mandated responsibilities to  
24 produce forecasts and assessments of different energy uses  
25 in California and that is true for transportation energy as

1 well. And so we at the Fuels and Transportation Division  
2 always have to do our share of forecasting and scenario  
3 development and assessments. So we hope that the product  
4 that we produce is valuable to the IEPR as well as other  
5 uses.

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

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

25 Since our forecasts look at a wide variety of

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

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

1 2003 consumption level, achieving that reduction by 2020.  
2 And then the next goal would be the alternative fuel use, 26  
3 percent alternative fuel use by 2022.

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

1 approximation.

2           One correction, the bar charts which correspond to  
3 the axis on the right, which really is illustrating the  
4 volumetric difference between the goal and our forecast, in  
5 the legend it actually says "high to actual", which is not  
6 true, it is not high to actual. It is actually the high to  
7 goal and the low to goal difference.

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

14           And then next would be the alternative fuel goal.  
15 And this is just using all of the results from the 2009 IEPR  
16 for the high and low petroleum demand numbers, pulling out  
17 all of the alternative fuels including the blended ethanol  
18 volumes from the gasoline, creating a BTU content  
19 calculation and just going with a straight percentage and  
20 representing it here through the forecast period. As  
21 mentioned in the previous slide, the goal is 26 percent by  
22 2020. And I haven't illustrated that here but it's a little  
23 bit above the 25 percent mark here and we are obviously well  
24 below, given our 2009 IEPR results. So that might well  
25 change with the addition of other policies that we are

1 analyzing in this IEPR round as well as our different price  
2 tracks, which we will be discussing. They will be different  
3 from the last IEPR cycle but I wanted to illustrate part of  
4 the comparisons that we will be doing for our IEPR this time  
5 around. If there are other goals or things that are  
6 important that would be well represented or what you would  
7 like to be represented or analyzed by staff, we would  
8 appreciate direction to what those goals would be.

9           So the next is a data flow chart. It basically  
10 represents our modeling work. It includes the inputs at the  
11 top of the chart showing basically all the different types  
12 of inputs - there are others as well but this is a  
13 representation of some of the major ones - and where all of  
14 those inputs feed into. The blue boxes here represent the  
15 simulation models, the models we have, econometric models  
16 that we have and the different sectors that are represented  
17 in our models. The gray box to the right for off-road is  
18 not something we have internalized in our models but we do  
19 calculate that in a separate cut of calculation. The blue  
20 dotted box there, Congestion & Feedback, that's something  
21 that we had a little bit of feedback between the models in  
22 2009. This time around we have expanded that capability and  
23 so certainly the congestion component is something new. It  
24 will be interesting to see how that congestion plays a role  
25 in people's choices, both in mode and in vehicle stock. So

1 we are eager to see how that new component or module affects  
2 the overall demand. Down below the green box is obviously  
3 the result of our analysis, which would be the overall  
4 California transportation energy fuel demand. And then to  
5 the right in red are the supply side implications of our  
6 demand forecast as well as the supply/demand balance which  
7 we use at the base year to gauge how close we are to actual.  
8 So we use that as kind of a calibration point. And that's  
9 why there is a two-way arrow down at the bottom between the  
10 green and the red there.

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

22 And this next slide is not the quite the full list  
23 of all inputs but this is high level inputs that we use in  
24 our models as well as the sources for those inputs.  
25 Obviously, we will be talking this afternoon a little bit

1 more specifically about the fuel prices that we will be  
2 using. And we will go into detail about what sources we are  
3 using for those. In the base year we use BOE and staff  
4 calculations as well as EIA to determine what our base  
5 number for consumption is that we should be using in our  
6 base year.

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

18           One of the other big inputs that is kind of pivotal  
19 to or analysis is the projections of vehicle attributes.  
20 And this is done by class. This is a product of consultant  
21 work, ICF. We have had them performing these vehicle  
22 attributes, these projections for us for the past few IEPR  
23 cycles, perhaps all the IEPR cycles really. And it really  
24 is an important input into our models. It determines what  
25 the marginal cost of any specific technology is against any

1 other technology. It gives us all of our efficiency  
2 numbers, it gives us many of the inputs to the vehicles and  
3 the types of vehicles. And that influences not only the  
4 final consumption, not only the number of miles which are  
5 traveled, but also what vehicles are acquired in California  
6 in the future. And that's done through the vehicle choice  
7 component of our models.

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

19           So the demand scenarios that we are proposing for  
20 the 2011 IEPR are these. Basically, a high and a low  
21 petroleum demand. The emphasis here is on petroleum demand.  
22 In the past we have kind of emphasized that as our high and  
23 low categories. Of course, embedded in that we look at the  
24 alternative fuels and how they compete in the marketplace  
25 against the petroleum fuels. And that is represented in the

1 transportation fuel prices, the two cases that we have. So  
2 in the situation where we have a high petroleum demand,  
3 obviously we are going to be seeing a low petroleum fuel  
4 price and a high natural gas and electricity price, which  
5 would cause the petroleum demand number to be the highest  
6 that it potentially could be.

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

21           So I touched on it earlier. But explicitly the  
22 methodology we are going to use is a two step approach. The  
23 initial modeling of demand is going to come as an output  
24 from our models and that's a product of all of our modeling  
25 and all the inputs that go into the model. And then after

1 that there is some post-processing work that occurs. It  
2 occurs for a couple of different reasons. Some of it is  
3 policy analysis and some of it is actually to quantify  
4 demand in certain areas. And I will go into detail in a few  
5 slides.

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

23           We will also be updating our transit information  
24 with Energy Commission surveys of transit agencies. We  
25 collect information from transit agencies to feed into our

1 models. And we are looking at hopefully expanding the  
2 number of transit agencies represented there and getting a  
3 better set of data as well. Lastly, I just wanted to  
4 mention we will be using a different set of data than we did  
5 in the past for freight, with the Freight Analysis Framework  
6 data that is a little more updated than in the last IEPR  
7 cycle. We used a different data source and hopefully that  
8 will better represent and expand the analysis that we have  
9 for freight activity.

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

24 In some instances the resolution or impact of the  
25 policies are regional in nature and that's not something we

1 can represent in our model as well. So in the case of ship  
2 electrification, the work that was done on that was done  
3 numerous years ago. Things have changed in the marketplace.  
4 The estimates that were used as the basis of those, that  
5 reduction, may not necessarily be true today. So those  
6 things have changed as well as the regional impacts would  
7 obviously be at certain ports that you would see these  
8 impacts. You know, we might be able to do some type of  
9 analysis after the fact but incorporating those into our  
10 model, it's not possible since our model really doesn't have  
11 that capability to look at, like, ship electrification.

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

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

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

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

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

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

23 MR. OLSON: Thanks, Malachi. A couple of comments  
24 first on the 15 percent petroleum reduction. That reflects  
25 the Pavley and the CAFE standard impact? And can you show

1 that in your graphic somehow, that contribution?

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

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

23 MR. WENG-GUTIERREZ: Sure.

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

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

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

8           MR. WENG-GUTIERREZ:    Sure.

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

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

17           MR. OLSON:    Very good.

18                    One other comment about - and it goes to your  
19 report. I don't know if this is premature to talk about  
20 this point.

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

22           MR. OLSON:    It's on page 27 in the report,  
23 referring to how electricity consumption is captured for  
24 electric vehicles. You have a reference to - you're using  
25 utility rate schedule tariffs that are additive in nature,

1 meaning household use increases.

2 MR. WENG-GUTIERREZ: Yes.

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

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

17 MR. OLSON: And just one other comment on your  
18 methodology and how you address the supply side of this, the  
19 data and the inputs on supply. I think it would be really  
20 good to get some additional input from some of the  
21 alternative fuel industry people. Some of them have their  
22 own associations like the - well, the PEV Collaborative is a  
23 35 member group, it includes utilities, automakers. That's  
24 a good data source for lots of different things, cost of  
25 vehicles, market penetration types of things. Same thing on

1 the Natural Gas Vehicle Coalition. Industrial gas companies  
2 that we are funding for these hydrogen fueling stations will  
3 give us some more insights on hydrogen pricing. And Western  
4 Propane Research Council on propane.

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

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

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

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

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

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

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

19 MR. WENG-GUTIERREZ: Right. And I guess I'm kind  
20 of jumping ahead to our next step slide. But we are going  
21 to be having an infrastructure workshop in May and we are  
22 hoping to touch on all of those types of topics. And  
23 certainly infrastructure is a big component, certainly with  
24 the alternative fuels entering the market, what is the  
25 infrastructure going to be? The Energy Commission as a

1 whole, AB 118, funds a lot of those infrastructure things.  
2 What are the results of our investments? How is that going  
3 to change the picture in the future? All of that really we  
4 are going to be starting to take into consideration as we  
5 move to the next workshop.

6 MR. BAMBERG: Thank you very much.

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

9 (No response.)

10 If not, then we have a WebEx question.

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

14 I'm just reading the question here.

15 Okay, well, as with previous IEPRs I think the  
16 difficulty and the challenge of including hydrogen vehicles  
17 is really the uncertainties associated with their costs and  
18 the attributes of those vehicles. So, you know, we can  
19 check again and see how comfortable we are with projections  
20 of vehicle attributes of that technology. But my thought is  
21 that, again, it's still early in the process for defining  
22 what vehicles will come to market at what price. We will be  
23 including in our work projections of hydrogen fueling  
24 prices. But as far as the demand side analysis, it may be  
25 limited by the input data that we have. Maybe it's

1 something we could include but we would have to get a better  
2 picture about what those input values would be.

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

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

15 So if there are any other questions.

16 (No response.)

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

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

1 price cases.

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

10           From 1983 to 1998 expenditures as a percentage of  
11 income have been falling from just above 3.5 percent all the  
12 way down to 1.6 percent. Most of this decline was caused by  
13 rising per capita income during this time period. From 1998  
14 to 2002 expenditures as a percentage of income remained  
15 fairly steady, only once going above two percent. Then when  
16 gasoline prices began to rise from 2002 to 2008 expenditures  
17 also increased as a percentage of income, all the way up to  
18 3.1 percent in 2008. When gasoline prices for the US fell  
19 in 2009, expenditures as a percentage of income also fell  
20 down to 2.25 percent.

21           Since most of the transportation fuels here in  
22 California are mostly tied to crude oil prices currently,  
23 here are some of the factors that affect crude oil prices.  
24 The big one being, of course, the supply and demand  
25 fundamentals on the world market for crude oil prices. Most

1 of these other factors play into that dynamic. All I'm  
2 saying here is when supply outpaces demand for crude oil  
3 prices tend to be low, whereas when demand picks up like,  
4 say, developing economies such as China, which recently  
5 increased its imports of crude oil 42 percent, prices tend  
6 to pick up as well.

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

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

1           To show just how supply and demand affect crude oil  
2 prices I have prepared the following chart. On this chart  
3 in green is Refiner Acquisition Cost of crude oil and the  
4 bars on this particular chart show the difference between  
5 world oil consumption and production in any given month  
6 along the chart's bottom axis. What we see here is red bars  
7 which indicate consumption outpacing production in a given  
8 month. It puts an upward pressure on prices. The black  
9 bars correspond to downward trends in crude oil prices as  
10 the world market becomes more saturated with supply. Some  
11 of the best examples of where long-run consumption outpacing  
12 production has led to higher prices can be seen by the  
13 arrows that I have put on this chart, that is, from January  
14 1999 to January 2000, then from January 2002 to July 2003  
15 and finally in the recent price spike which occurred from  
16 January 2007 all the way up into July of 2008.

17           For the most part these supply and demand  
18 fundamentals explain most of the price changes on this  
19 particular chart with one notable exception, which occurred  
20 from January 2003 all the way into January 2006. One  
21 possible explanation for this rise in price is the dollar  
22 value on the world market. Shown here by the blue line is  
23 the dollar per euro exchange rate. As this line increases  
24 the dollar becomes weaker, thus putting on upward pressure  
25 on prices. I would also like to point out that during the

1 most recent price spike we had both consumption outpacing  
2 production along with the weakening dollar, which is one  
3 possible explanation of why prices increased so dramatically  
4 during that time period.

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

17           Staff's solution to some of these problems is  
18 basically to use somebody else's forecast, specifically  
19 either from the EIA, IEA or some other agency. Staff then  
20 uses Imported Refiner Acquisition Cost, which is a sales-  
21 weighted average of crude oil for refiners, and then creates  
22 a relationship to other state fuels in order to give us some  
23 kind of pegging system in order to project these fuels into  
24 the future. Staff has also endeavored to consult with other  
25 offices within the Energy Commission on E85, natural gas,

1 hydrogen as well as our electric rates for EVs and plug-in  
2 hybrids. Of course, staff would like to solicit any outside  
3 advice from workshop participants on any of our price cases  
4 in order to better refine them for the 2011 IEPR.

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

18           Refiner Acquisition Cost averages all of these for  
19 inputs to refineries here in the United States and kind of  
20 gives us an average of what crude oil was being paid for by  
21 the refineries. At the beginning of any sort of forecasting  
22 endeavor usually forecasters look at past behavior in order  
23 to project what the future is going to hold. Shown here is  
24 Refiner Acquisition Cost in historical terms, denoted by the  
25 two purple lines on this particular chart, the solid line

1 being the inflation-adjusted prices with the dotted line  
2 being the nominal or posted price of crude oil in this time  
3 period. What we see here is that for the most part from  
4 1968 to 2010 crude oil has been fairly stable with, of  
5 course, to obvious and very big price departures from that  
6 stability level. These in the past have been created  
7 through supply shocks. Also shown on this chart are our  
8 proposed crude oil price cases. Again solid lines represent  
9 inflation-adjusted dollars for these particular price  
10 projections.

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

24           Staff also looked at our past price projections and  
25 historical values of that time frame, shown here by the red

1 line, which is our 2009 IEPR high price case and the purple  
2 line is our low case. The green dotted line in this  
3 particular chart is the actual average monthly imported  
4 Refiner Acquisition Cost and how it performed during this  
5 time period. For the purposes of this chart alone staff has  
6 converted our yearly price cases into a monthly form. And  
7 as you can see for the most part Refiner Acquisition Cost  
8 stayed within the band, starting at the low end at the  
9 beginning of 2009 and then rising to the high end of our  
10 band in early 2010, then as 2010 progressed Refiner  
11 Acquisition Cost dipped back down to within the band.

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

24           When looking at the futures we see a pretty steep  
25 contango in the early years of the NYMEX futures with a

1 backwardation towards the longer time periods out into the  
2 five year range. In January when these price bands were  
3 being developed, our reading of the NYMEX futures was that  
4 over the long haul prices were going to be fairly steady  
5 throughout the first five years of our price projections.

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

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

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

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

12 We also made some assumptions in creating these  
13 price cases, the first being that in real terms all fuel  
14 margins for all the fuels are held constant within the  
15 projection period. Thus, when putting in inflation, which  
16 tends to be on the positive end, these margins are actually  
17 likely to grow in nominal terms. Also all taxes and fees  
18 are held constant in real terms. Again that means in  
19 nominal terms they will be rising. Staff has also assumed  
20 that all fuel formulations will remain constant into the  
21 projection period, meaning these prices do not reflect a  
22 transformation to, say, an E15 blend for gasoline. We have  
23 also incorporated no greenhouse gas reduction regulations  
24 beyond the Pavley rules. However, we would like to solicit  
25 any input on, say, policies such as the low carbon fuel

1 standard and AB32 and how they are likely to affect prices.  
2 Currently, we still have not been able to quantify an adder  
3 to prices in order to account for these regulations.

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

22           These are our proposed crude to retail margins that  
23 we are proposing to use for the upcoming 2011 IEPR with  
24 regards to gasoline and diesel. In the high case we are  
25 intending to use a 79.9 crude to retail margin for gasoline

1 and a 83.9 retail margin for diesel. In the low case the  
2 crude to retail margin would be 6.4 cents and 76.3 cents.  
3 Also, as I mentioned before, there have been some changes in  
4 the gasoline tax structure here in California. Our state  
5 excise tax has risen from 18 cents to 35.3 cents. In the  
6 case of diesel that 18 cent excise tax has been lowered to  
7 13.6 cents. Also sales tax on these two different fuels has  
8 changed as well. In the case of gasoline it has fallen from  
9 8.25 percent to 3.25 percent. In the case of diesel it has  
10 risen from 8.25 percent to 10 percent.

11           Using the price projection methodology here are the  
12 following results in real 2010 cents. In the high case  
13 gasoline starts at \$3.76 a gallon in 2011 and diesel starts  
14 at \$3.72 in 2011 in the high case. They then move to \$4.28  
15 and \$4.37, respectively, by 2015. Then by 2030 the price of  
16 gasoline would be \$4.70 and the price of diesel would be  
17 \$4.82 in the high case. In the low case gasoline prices  
18 start at \$3.24 for 2011 and diesel starts at \$3.27 in 2011.  
19 By 2015 these prices move to \$3.39 and \$3.43, respectively.  
20 Then by the end in 2030 prices fall to \$3.20 and \$3.22,  
21 respectively. Values for this chart can be found on page  
22 19, Table 4 of staff's accompanying document for this  
23 workshop.

24           That being said, these are also likely not to be the  
25 prices consumers experience at the pump in 2030. Instead,

1 when adjusting for inflation using the same EIA 2011 annual  
2 energy outlook reference forecast for inflation, in 2030 the  
3 price of gasoline would be closer to \$6.70 a gallon and  
4 \$6.94 for diesel in the high case. In the low case,  
5 gasoline in 2030 would be \$4.60 a gallon and diesel would be  
6 \$4.63 a gallon.

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

18           Using this methodology this chart shows the  
19 resulting prices from that methodology. In 2011 the price  
20 of railroad diesel would be \$3.07 in the high case and \$2.62  
21 a gallon in the low case. By 2020 railroad diesel prices  
22 would be \$3.80 and \$2.69 a gallon. Finally, by 2030 the  
23 price of railroad diesel in the high case would be \$4.15 and  
24 \$2.57 in the low case. Of course, these are all inflation-  
25 adjusted 2010 dollar projections here. In the case of jet

1 fuel prices begin at \$2.81 a gallon in the high case and  
2 \$2.26 in the low case. By 2020 jet fuel is \$3.49 in the  
3 high case and \$2.33 in the low case. Finally, by 2030 jet  
4 fuel is \$3.81 in the high case and \$2.22 in the low case.  
5 Values for this chart can be found on page 22, Table 5 of  
6 staff's accompanying document for this workshop.

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

21           Shown here are our gasoline price cases and E85  
22 price cases. As you can see, they have roughly the same  
23 general shape with E85 prices being lower because it is  
24 being divided by roughly 30 percent just for BTU content.  
25 The green lines on this particular chart show the E85 price

1 cases. And in this particular diagram E85 prices begin at  
2 \$2.68 in the high case and \$2.37 in the low case in 2011.  
3 Then by 2015 they move to \$3.12 in the high case and \$2.48 in  
4 the low case. By 2030 E85 is \$3.43 a gallon in the high  
5 case and \$2.33 in the low case.

6 This particular chart shows our proposed B5 price  
7 and propane price cases. B5 is the two purple lines, the  
8 low case being the dotted line and the high case being the  
9 solid line. Propane is shown here as the red line, the high  
10 case is the solid line and the low case is the dotted line.  
11 In the high price case B5 starts at \$3.72 a gallon and  
12 propane starts at \$2.89 a gallon in 2011. By 2015 these  
13 prices rise to \$4.37 a gallon for B5 and \$3.42 a gallon for  
14 propane. By 2030 in the high case B5 is \$4.82 a gallon and  
15 propane is \$3.79 a gallon. In the low case B5 starts at  
16 \$3.27 a gallon with propane being \$2.40 a gallon in 2011.  
17 By 2015 these prices move to \$3.43 a gallon for B5 and \$2.57  
18 a gallon for propane. Finally, in 2030 in the low case B5  
19 is \$3.22 a gallon and propane is \$2.37 a gallon. Values for  
20 E85, B5 and propane can all be found on page 25, Table 6 of  
21 staff's document for this workshop.

22 The final slide I plan on presenting today is our  
23 price forecast methodology for transportation, natural gas  
24 and hydrogen. Staff intends to use the same fixed margin  
25 methodology established in our previous IEPR work. Both of

1 these fuels will use natural gas projections consistent with  
2 those used by other offices and talked about earlier today.

3           In the case of CNG, the Henry Hub forecast will be  
4 transformed into a California Citygate with margins of five  
5 cents and two cents in the low case being added to that  
6 price to turn it into a Citygate price. If the Natural Gas  
7 Office provides us with actual Citygate forecasts we will  
8 use those Citygate forecasts instead of the Henry Hub  
9 forecast. Then PG&E transportation CNG cost margins of  
10 \$1.62 per therm will then be added to the Citygate price.  
11 And then the appropriate federal road excise tax of 18 cents  
12 per GGE and 8.25 percent sales tax will then be added to  
13 create a final retail price.

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

24           This is the last slide of my presentation before I  
25 turn it over to Malachi Weng-Gutierrez to discuss our

1 electricity rates. Are there any questions at this time  
2 regarding my presentation?

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

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

21 MR. SCHREMP: Yes, Tim. This is Gordon Schremp,  
22 Energy Commission staff. Also as part of that analysis,  
23 which I think we can do, we would have to estimate what the  
24 imported crude oil price is. We wouldn't actually have the  
25 individual prices by source country. But we also have to

1 take into consideration, with rising prices and rising costs  
2 and rising imports that are on one side of the ledger, I'm  
3 sure there is some sort of economic benefit, if you will, to  
4 the oil production industry in California with those rising  
5 prices. There is some economic gain in jobs and activity  
6 associated with that.

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

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

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

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

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

20           Any other questions? I think we have one online.

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

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

1 And, yes, they are.

2 Any further online questions?

3 (No response.)

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

6 MR. WENG-GUTIERREZ: Thank you, Ryan.

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

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

24 But there are certain volumes, certainly in what I  
25 presented from the 2009 IEPR that we will have as part of

1 our 2011 IEPR, where we will be making the assumption that  
2 alternative fuels will be supplanting gasoline demand. And  
3 I think the question here is whether or not there are  
4 sufficient commercial quantities of renewable and  
5 alternative fuels to fill that gap. And I think that's  
6 probably something that we will be discussing in our policy  
7 analyses, certainly something we will be talking about in  
8 our discussions of specific policies, RFS2 and LCFS come to  
9 mind as being fairly significant. And certainly I think we  
10 touched on those in 2009. We certainly will talk about them  
11 to a greater extent, I think, this IEPR cycle. And I also  
12 want to note that the upcoming - not to plug our workshops  
13 again, but the May workshop, I think, when we are going to  
14 be touching on infrastructure I think we will be looking at  
15 production capacity and the implications for how that is  
16 going to come to market and whether or not those are  
17 reasonable.

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

20           Is there a follow-up question then?

21           (No response.)

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

24           For electricity prices I basically used a similar  
25 methodology that I used in the last IEPR cycle to derive the

1 transportation electricity prices that I would be using,  
2 that we are going to be using in our models. It's based on  
3 rates that exist today, those which are out there and those  
4 discounts that are offered by the utilities today. We did  
5 update our rates to the existing rates so we are reflecting  
6 what the current rate structure in the MOUs and IOUs that we  
7 looked at. As you mentioned, Tim, to a certain extent it is  
8 a marginal analysis. So in those cases where we have a  
9 tiered pricing structure where there are both single and  
10 dual meter rates offered we did attribute a portion of the  
11 overall average number that we calculated to the single  
12 meter situation as well as partially to the dual meter  
13 situation. And, again, I will touch on that a little bit  
14 later.

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

24 So what Chris used as his growth pattern for high  
25 and low prices we would then apply to our base year number

1 and grow throughout the forecast period as well. And the  
2 justification for that really is that we see no reason why  
3 the price impacts that they are representing in their price  
4 forecast wouldn't also apply to the tariff rates that  
5 specifically applied to electric vehicles. I mean, there  
6 could be situations where you wouldn't do that but our  
7 assumption is that they will be constant.

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

22           So I did a couple of analyses, one of which was I  
23 took a look at historic data. It is FERC data that was  
24 reported for PG&E, SCE and SDG&E for rates that were dual  
25 meter rates. So I'm assuming that those consumptions for

1 those rates were only associated with electric vehicle  
2 consumption. Again, the tariffs that I looked at were  
3 specific to electric vehicles. So in the case of PG&E I  
4 looked at the E9 rate B, which is a dual meter rate which  
5 has its own set of prices and everything, and I could see  
6 how many people and how much was consumed and then estimate  
7 the monthly consumption according to that. So I did that  
8 and I made some assumptions about overall electricity  
9 efficiency of the vehicles. And then I came out with this  
10 monthly VMT as well as this monthly consumption number. And  
11 it ended up being 188 KWh per month. And that was just  
12 using the FERC data as the basis of that. And that's the  
13 2009 number, I believe. So it's using FERC data from 2009  
14 to come up with an estimate of per month KWh consumption.  
15 That was something I could kind of peg my analysis to, to  
16 see whether or not I'm in the ballpark.

17           The second method I used to determine, something  
18 that I had done last IEPR cycle, was to come up with a  
19 potential range of VMT that you would observe or use an  
20 electric vehicle for, look at the distribution of  
21 efficiencies that are published for different electric  
22 vehicles in the marketplace, and then use a Monte Carlo  
23 simulation to estimate how much would be consumed by any  
24 household with these vehicles in them. So basically a range  
25 of VMT, a range of efficiencies, how much would be consumed

1 given the distribution across those two variables. And I  
2 came up with 175 KWh per month as a mean value. So there is  
3 certainly obviously a wider distribution of potential  
4 consumption but the mean was 175. And I thought the 188 and  
5 175 were pretty close, that's not too bad. It's in the same  
6 ballpark, I thought.

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

20           Now, something that I think that I would like some  
21 feedback on - certainly there are other studies out there  
22 but the one study that we used last year and that I kind of  
23 plugged in in this analysis to come up with these prices was  
24 a PG&E study that I think was performed in 1998, which  
25 showed that there was 88 percent off- charging, eight

1 percent partial peak and then four percent on-peak charging.  
2 That obviously is an older study, there have been other more  
3 recent studies. Certainly it would be interesting to hear  
4 what people have to say about what would be the appropriate  
5 load profile of an EV at a house when they charge. There is  
6 a lot of uncertainty about that. And that may influence the  
7 final rate that a residential consumer would see. So any  
8 information that people can provide or participants in this  
9 workshop can provide on that would be helpful.

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

21           And I just wanted to show, for the FERC data I  
22 looked at SCE and PG&E for the last eight years to see what  
23 the per kWh revenue looked like, just to get a sense again  
24 of whether or not the estimate that I was using as a  
25 statewide number looked reasonable in the context of

1 existing reported revenue per KWh values. So you can see  
2 here that in 2009, which is kind of our base year value, the  
3 tariff rates that I looked, which were the two dual metered  
4 rates, they came out to be an average - the green line is  
5 the sales-weighted average number - of over 14 cents per  
6 KWh. The number that we were using as the basis of ours was  
7 12.6 or 12.58 cents per KWh, was the number that I  
8 calculated for that base year of 2009. So ours was  
9 substantially lower than this sales-weighted number value.  
10 But it is kind of in the ballpark, certainly between these  
11 two utilities.

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

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

19           And then just as a final slide I wanted to highlight  
20 some of the assumptions and simplifications in this  
21 analysis. Obviously, there are differences in overall  
22 consumption for single family homes versus multi-family  
23 dwellings. The consumption patterns are different, the  
24 tariffs applied to them are different, and those really  
25 weren't considered specifically. We really didn't consider

1 how much significantly subsidized public charging was  
2 offered or free charging. We are just trying to develop a  
3 price forecast so have a price value that we are going to  
4 set as an input. If there are in the short term free  
5 charging stations, like across the street in the parking  
6 structure where, you know, there is no credit card slot for  
7 me to put in when I pull up with my EV, there is no way for  
8 us to represent that in the short term. And I haven't  
9 accounted for that in my price forecast.

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

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

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

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

19           MR. OLSON: Just another kind of reminder. The  
20 electric transportation rate and tariff topic is evolving  
21 quickly, changing almost every day. It is good to get  
22 connected up to the CPUC, OIR, smart grid, electric  
23 transportation. Tariffs are a big part of that. It would  
24 be good to get into our record what the utilities are  
25 planning, including SMUD, what they are planning in terms of

1 their specific tariff schedules. And, I mean, it's a ground  
2 truthing thing that we need to add to this that will  
3 probably help you in reducing those uncertainties.

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

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

16 (No response.)

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

19 MS. GREY: Hello.

20 MR. WENG-GUTIERREZ: Hi, Gina.

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

1 address the two questions that I had submitted earlier.

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

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

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

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

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

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

1 going to be addressing, currently anyway, hydrogen.

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

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

21           The infrastructure side, I think, is something  
22 different. That's something we can certainly take - it has  
23 its own set of challenges and things that we want to take a  
24 look at.

25           MS. GREY: I guess my question, though, would be if

1 there is another state agency that supposedly has identified  
2 a demand and they have put some numbers to it, should that  
3 not be coordinated with you folks in the sense that you  
4 could also utilize either the same estimates or come up with  
5 your own estimates in terms of what the demand seems to be.  
6 You know, understanding that within your detailed report you  
7 do have some forecast to indicate potentially a drop  
8 actually in hydrogen demand within the next few years. So  
9 all we are asking for is basically some more coordination  
10 between state agencies on this so we don't have one hand  
11 doing one thing and another hand doing another.

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

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

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

1 MS. GREY: Okay. Thank you.

2 MR. WENG-GUTIERREZ: Thank you.

3 Any other questions from online?

4 (No response.)

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

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

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

24 So here is a laundry list of the topics I will be  
25 covering during my presentation. The first is an

1 examination of two policies, one federal and one state.  
2 They do, we believe, impact or demand forecast for both  
3 gasoline and diesel fuel. I will also be looking at  
4 infrastructure assessments associated with our overall  
5 demand and changing mix of transportation fuels as well as  
6 going into a discussion of two major areas of advanced  
7 biofuel technologies that are intended to produce  
8 transportation fuels. And then I will be discussing crude  
9 oil. We do crude oil analysis as part of our IEPR work  
10 every two years, both import and infrastructure assessment.  
11 And this will also include what we refer to as crude oil  
12 screening, our work associated with the low carbon fuel  
13 standard. And then the final laundry list of a number of  
14 topics that will also be included in our work and  
15 assessments: marine oil terminal engineering and  
16 maintenance standards, or MOTEMS, the new ozone standard  
17 that Malachi mentioned earlier, we do look at agricultural  
18 commodities because of the increased use of biofuels sourced  
19 from agricultural products as feedstock, import tariffs are  
20 becoming more of a subject du jour, as well as blending  
21 credits - those have to do with the renewable identification  
22 number, and I will talk about that - and finally I will be  
23 briefly mentioning the BP oil spill in the gulf last year as  
24 well as energy security, which has been a topic of the  
25 Energy Commission in years past.

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

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

21           Now some of the impact assessments we will be  
22 looking at are what are those demand projections for various  
23 types of ethanol as well as biodiesel. And for ethanol,  
24 certainly, we do look at feedstock when it comes to  
25 traditional ethanol production as corn. And I'll touch on

1 that a little bit later. And we will be looking at what  
2 level of displacement of gasoline is occurring in California  
3 compared to our initial forecast that Malachi was mentioning  
4 earlier. And then finally and very importantly what  
5 infrastructure might be necessary to bring into California  
6 and distribute an increased concentration in total renewable  
7 fuels.

8           This is a slide that illustrates the various  
9 categories of the renewable fuels under RFS2. I have  
10 highlighted one category, cellulosic biofuels. Those two  
11 numbers are billions of gallons. So you see the first one  
12 for 2010 is 100 million and the one for 2011 is 250 million  
13 gallons. The reason I point that is because this mandate  
14 for those minimum volumes in those categories does appear to  
15 have a bit of challenge at this point in time. Both of  
16 those numbers have been drastically reduced by USEPA in  
17 light of the fact that there is an inadequate volume of  
18 commercial scale cellulosic production in the United States  
19 at this time. And so the 250 million gallon mandate became  
20 6 million gallons in 2011 and it's likely the 500 million  
21 gallons for 2012 will be significantly reduced. We will  
22 find out later this year when USEIA does their initial  
23 assessment then sends a letter to USEPA with their  
24 recommendation on what to do depending on how much capacity  
25 they see coming up on a commercial scale.

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

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

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

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

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

25           E15 primarily has issues in California specifically

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

17           And I think most importantly from a retail station  
18 operator and owner perspective is that there is a liability  
19 for misfueling. Many of you may recall when lead in  
20 gasoline, or tetraethyl lead, was phased out and unleaded  
21 gasoline was used in the United States and phased in over a  
22 period of years, for that change in the retail  
23 infrastructure there were actually different sized nozzles  
24 deployed, where you actually really couldn't put leaded  
25 gasoline into your unleaded vehicle unless you held back the

1 nozzle and let it sort of drip into your tank past that  
2 little safety device installed inside the tank. So there  
3 was a physical change at the retail dispensers to sort of  
4 prevent misfueling.

5 Well, in this case there is no physical barrier to  
6 prevent that. And therefore USEPA is depending on warnings  
7 posted on dispensers to provide enough information to a  
8 consumer that pulls up to the dispenser to not misfuel into  
9 their older vehicle. I failed to mention that the waiver,  
10 the two-part waiver that USEPA has ruled on, is for vehicles  
11 2001 model year and newer, which is about two-thirds of the  
12 existing fleet in 2011 for light duty vehicles and sport  
13 utility vehicles. So this is a rather significant portion  
14 of the total fleet in existence.

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

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

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

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

1 dispensers.

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

22           The Low Carbon Fuel Standard, unlike the federal, is  
23 a per gallon ratcheting down goal, ever lower carbon  
24 intensity, starting off modestly at first and becoming a  
25 little bit more aggressive over ten years. So it's gasoline

1 and diesel, it's not other fuels or even lube oils and other  
2 non-transportation fuels. And it went into effect for  
3 obligated parties January 1st of this year. However, there  
4 are some elements of the regulation yet to be finalized.  
5 And these are non-trivial, these are important and I think a  
6 lot of parties are aggressively working to reach some sort  
7 of place where there is finalization on these aspects. And  
8 these include a credit trading system that you could buy and  
9 sell credits to achieve compliance as well as transparency  
10 of what those values are; crude oil screening, that I will  
11 talk about in a little bit; and indirect land use for carbon  
12 intensity and how that's changed and how that will change  
13 the ability for people to comply and make it easier or  
14 harder or the same.

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

1 things like sugarcane-based ethanol with that indirect land  
2 use change. The value is in how much that may change.

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

14           So what does that look like? Well, some preliminary  
15 analysis shows - the bars on the bottom is when there is  
16 some generation of excess credits above and beyond what you  
17 would need to sort of balance out collectively, as all the  
18 obligated parties in California. So this is based on our  
19 2009 forecast. And, of course, we will be updating this in  
20 two aspects. One, we will have new forecast numbers and  
21 there will be hopefully sometime soon a resolution on what  
22 the indirect land use change, how much that will be altered;  
23 and then how much the per year goals may or may no be  
24 changed and what does that mean to calculating these kinds  
25 of debits and credits. So this is just an example.

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

9 Another very important aspect besides the post-  
10 processing of our demand forecast is, what about the  
11 infrastructure? The infrastructure is both for crude oil,  
12 traditional fuels, petroleum-based fuels, as well as  
13 renewable fuels. And this graphic is only meant to  
14 illustrate I think part of the complexity of the system in  
15 California. Liquid coming in, the blue lines, and then  
16 being dispensed on the black lines, which are product  
17 pipelines in this case, petroleum product pipelines. And  
18 then showing multiple states because the region is tied  
19 together in supply. There are 22 refineries in California,  
20 the refineries in Washington state. The other states in  
21 this graphic have no refineries at this time. And so Nevada  
22 relies nearly a hundred percent on California for its  
23 transportation fuels and Arizona about half of their fuel.  
24 So that's important when we look at infrastructure and we  
25 look at our demand forecast for imports. Because how demand

1 is changing in those neighboring states supplied from  
2 California facilities will have an impact on our  
3 infrastructure assessment.

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

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

1 suggest a bracketed range of what that might be as part of  
2 our analysis.

3           There are two main areas of advanced biofuel  
4 technologies that we intend to put some effort in to cover a  
5 broad range of topics and give as much substantial  
6 information as we can put forth. And, as listed here, we  
7 are going to lay out the various types of primary  
8 technologies for Algal fuels. What is their supply  
9 potential? This is usually a very important and often not  
10 asked enough question. There may be a very good technology  
11 but it may have some significant supply potential. So we  
12 intend to illustrate what that can be and this can be  
13 substantial actually for Algal. Estimated production costs  
14 are very important. This is probably a challenge we are  
15 seeing with cellulosic at this time. We will look at pilot  
16 status as well as commercial. Some of that is actually  
17 starting. And the final issue is suitability, what you see  
18 in the chart at the lower right. The yellow areas are  
19 thought to be more suitable regions for both the open pond  
20 as well as the closed photo-bioreactors using natural  
21 sunlight, not artificial light. So Algal fuels are very  
22 promising in a number of aspects. They have quite a bit of  
23 co-products that can be used, they have a lot of versatility  
24 in what kind of hydrocarbons or what you can do with the  
25 oils, actually, as well as what you can do with the biomass

1 material that is powdered and you can actually use that as  
2 an input to a refinery. So we will try to do our best to  
3 cover this. And we definitely appreciate input from  
4 stakeholders who have far greater expertise than staff does  
5 on this subject matter as we move forward.

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

16           I think an important element of these kinds of  
17 renewable hydrocarbon fuels is what people refer to as "drop  
18 in". That means really no special infrastructure. You can  
19 blend these in the gasoline boiling range, you can put them  
20 with gasoline blend stocks in common storage tanks, pipeline  
21 distribution, nothing special at retail, nothing special at  
22 the intermediate distribution infrastructure. The same goes  
23 for jet fuel and diesel fuel. So that's an important  
24 element moving forward when one looks at infrastructure  
25 requirements for a new type of fuel such as this. And once

1 again to reiterate, we believe this type of fuel is  
2 something that one would need to help achieve compliance  
3 with the LCFS in the latter years.

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

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

1 realistic scenario. And I will touch on that in just a  
2 minute.

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

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

1 years.

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

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

1 continue moving forward on this kind of project.

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

13           And so what the Energy Commission staff has done is  
14 a lot of work to come up with a list of what we call  
15 marketable crude oil names that are available globally and  
16 that have been imported to California. That list in excess  
17 of 250 - I think it is 257 - names and we have completed our  
18 initial analysis of screening them. Meaning a certain  
19 number of them are potential high carbon intensity crude  
20 oils. And you can see the results of this initial work in  
21 our pie chart on the left. And you see things like TEOR,  
22 thermally enhanced oil recovery. That's why they would fail  
23 this initial screen. It doesn't mean they can't be used it  
24 just means they fail the initial screening. And you see  
25 things like upgrading, meaning I took a real heavy thick

1 crude oil and I actually partially processed it to improve  
2 its viscosity and make it a lighter crude oil that I then  
3 sold into the marketplace. So clearly this type of  
4 regulation has the potential to, what we would characterize  
5 as, decrease the availability of crude oils. Because the  
6 refiners would shy away from something like this because  
7 using a potential high carbon intensity crude oil would  
8 accrue incremental debt, carbon debt so to speak, that would  
9 have to be offset.

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

20           MOTEMS are sort of the other catch-all category. It  
21 is part of the California Business Code now. This was  
22 designed over a long period of time and there is an  
23 extensive amount of thought behind it. And the purpose is  
24 actually to make the mooring facilities stronger to resist  
25 earthquakes and tsunamis, to the extent that there won't be

1 a leak from the vessel that is moored there. Some of the  
2 facilities in California date back to the 1920s and are  
3 still in use. A lot of wooden piers. And so those  
4 certainly weren't designed initially to hold the size of the  
5 vessels that are in some cases, you know, four, five, six,  
6 seven, eight times larger than they were when they were  
7 initially designed. It's not to imply that they are unsafe,  
8 they are safe to be used, obviously. But in the event of a  
9 certain sized magnitude earthquake or a certain sized  
10 tsunami there is a feeling there can be release.

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

21 Now we are into the more important stage and that  
22 is, who pays? And this is of particular interest in the  
23 Port of Los Angeles because they are the port's terminals  
24 and then attendants have leases, long-term leases or some  
25 month-to-month leases, as the case may be today. And so

1 there is some discussion on, well, do all of them need to be  
2 upgraded? Maybe not all of them because, you know, who is  
3 paying, how much are you going to pay or are they going to  
4 co-share? So part of that debate - the final sub-bullet  
5 here - is the Port of Los Angeles and to some extent the  
6 Port of Long Beach actually use our forecasts and they cite  
7 that in their literature and their letters to the State  
8 Lands Commission on what their intent is in not upgrading  
9 all of the facilities. So once again we will be doing our  
10 assessment, sort of a peak capacity look at this  
11 infrastructure. And that will be part of this decision-  
12 making process, whether to upgrade or not upgrade certain  
13 facilities.

14           The new ozone standard was proposed in January of  
15 last year initially. Seventy-five parts per billion is the  
16 standard and the proposal is to look at lowering that to  
17 somewhere between 60 and 70 parts per billion. Well, it  
18 doesn't seem like a lot but there is a significant amount of  
19 controversy associated with that. And as you note from the  
20 chart on the left, there are a number of additional  
21 locations that would be out of compliance if the standard  
22 were to be lowered as suggested. We don't know yet what  
23 that lowering may be, that is supposed to come out in July  
24 of this year. In that timing it may be too late for us to  
25 include the final proposed lowering but we will look at that

1 range. And what we essentially look at, I mean, there are  
2 myriad programs that air districts would employ to try to  
3 reduce the amount of ozone exceedances in their districts  
4 that may or may not include fuels. But certainly different  
5 fuel reformulations in places like Arizona and Nevada are  
6 something that we will pay attention to because there can be  
7 supply implications for one, depending on who can make these  
8 kinds of stricter standard fuels or more advanced  
9 reformulated fuels. And then, more importantly for Arizona,  
10 where would that be coming from, the west from California,  
11 putting a greater burden on the refining infrastructure  
12 here? And/or coming from the east? So we are very  
13 interested and we continue to work with people in Arizona  
14 and Nevada to understand how they may comply. Because as  
15 you can see from the chart there, there are some additional  
16 areas in both Nevada and Arizona that would come into play  
17 for the newer standards.

18 Agricultural commodities, I will sort of mention the  
19 obvious here. The ramping up of ethanol per the RFS2  
20 mandate and primarily almost solely met with traditional  
21 corn-based ethanol at this point in time, but limited as  
22 time goes by not to unduly impact the agricultural markets.  
23 But you can see here that there has been a rather strong  
24 increase in the quantity of corn in the red bars over the  
25 most recent years to be used to convert to fuel ethanol. So

1 we expect that to continue and in 2011 for corn to be the  
2 dominant use as a percent of all uses to produce fuel as  
3 compared to the other categories. So this does have an  
4 impact on market-clearing prices. There are many other  
5 factors involved in the commodity markets. There was a huge  
6 runup in 2008. Certainly that shouldn't be pegged to an  
7 increase solely on demand for corn-based ethanol, there are  
8 many other factors at play here. But over time, over the  
9 long run, this is a significant change in this use.

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

21           Another important source of ethanol under the Low  
22 Carbon Fuel Standard is ethanol produced from sugarcane. It  
23 has significantly low carbon intensity and we think that is  
24 going to have a high demand in California. Well, there is  
25 actually an import tariff that is a bit of an economic

1 challenge to use Brazilian ethanol in the United States and  
2 in California of course. And there are two forms of the  
3 tariff, it is a 54 cent a gallon as well as a 2.5 percent ad  
4 valorem on top of that. This has been raised in Congress  
5 and will be raised again. We certainly see that as a bit of  
6 an economic barrier. The lower prices of ethanol in the  
7 United States last year and continuing to this year have  
8 been so low in fact that Brazilian ethanol cannot compete in  
9 this marketplace with transporting here and paying this  
10 import tariff.

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

25           Another is credits. These charts on the left show

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

19           The BP oil spill last Spring, the Macondo well, we  
20 believe is the largest in world history for an accidental  
21 spill, not on purpose. That would be the initial Gulf War,  
22 that was an on-purpose spill into the gulf. We are looking  
23 at this. A lot of work has come out of this tragedy for  
24 both those killed and injured as well as damage to the  
25 environment and the economy, the local economy. There have

1 been suggested changes to drilling practices in the Gulf of  
2 Mexico. We want to discuss some of those, we want to do  
3 what we think is an important comparative to the gulf  
4 situation and the California situation. Certainly there is  
5 a moratorium off of the coast of California right now. But  
6 we want to talk about sort of where there are differences in  
7 the drilling environment. Are there differences and, if so,  
8 is that relevant? We want to look at the potential resource  
9 base information available for both regions.

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

21 A final element I just want to touch on today that  
22 we intend to pursue as part of our staff work is the area of  
23 energy security. This can be a whole report in and or  
24 itself and has in the past at the Energy Commission been a  
25 subject for workshops for this subject alone. But we would

1 like to sort of narrow this discussion in a couple of areas.  
2 And it has to do with certain types of fuels that we might  
3 have a growing dependence on that may fall under some  
4 definition of potential increased energy security concerns,  
5 like maybe looking to a fuel that is only available in one  
6 or two countries. Another is in the area of crude oil and  
7 that may have to do with the Low Carbon Fuel Standard and  
8 may be some crude oils being more challenging to use and  
9 having to go to other places that may not be as high on the  
10 energy security ranking as others.

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

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

23           VICE-CHAIR BOYD: Gordon, if I might, I have two or  
24 three questions. Your slide five, which referenced the  
25 reduction in cellulosic biofuels down to six million

1 gallons, can you tell us why this was reduced? Is this a  
2 lack of technology available to produce cellulosic biofuels?  
3 Or, if there is technology, is it a lack of adequate  
4 production capacity or production facilities to provide  
5 volumes much above six million? Or is this pure politics,  
6 is this pressure from the corn lobby to back off the  
7 competition?

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

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

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

22 What those challenges are, why after so many years  
23 of money and research and support and even, you know,  
24 mandated levels signaled years in advance, clearly there is  
25 something else going on with this technology. We don't

1 clearly understand it. We would hope to obtain input from  
2 more knowledgeable sources. Is there in fact somewhat of a  
3 technology and/or economic bridge that can't be crossed  
4 going from the demonstration plant level to the commercial  
5 scale? Does it now work when you get - it's not a scalable  
6 technology necessarily. Is there something in there on the  
7 technology side that is creating production issues just from  
8 an operational perspective and/or much higher economic cost  
9 in this environment of very low ethanol prices? These  
10 ethanol prices are extremely low because there is  
11 essentially a glut of ethanol, which is why the US set a  
12 record this year in how much ethanol they exported from this  
13 country, primarily to Europe and Canada and even some to  
14 South America.

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

25 But it is a bit disturbing because I know this is

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

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

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

23 MR. SCHREMP: Well, Commissioner Boyd, I would just  
24 clarify. That top blue line I guess you could say is  
25 indirect food. Feed the animals that we eventually feed

1 upon, cattle and hogs and stuff.

2 VICE-CHAIR BOYD: Yes, I know.

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

5 VICE-CHAIR BOYD: Right.

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

8 VICE-CHAIR BOYD: Never touch the stuff.

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

25 When is this going to get resolved? When might we

1 see 15 percent? Will we ever see 15 percent? Those of us  
2 who drive older vehicles, do we really have a problem with  
3 that?

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

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

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

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

17           I think a final point on this is the whole reason  
18 there was growth of energy, a primary reason they requested  
19 this waiver, is because they like others saw that that large  
20 36 billion gallon ratcheting up of RFS2 mandated minimum  
21 volumes was going to broach this E10 blend wall. And they  
22 go, well, gosh, at least E15 should be no harm, no foul in  
23 the vehicles and that should be okay. Quickly do that and  
24 then, you know, stave off the point where you go beyond the  
25 wall. Because once you go beyond the wall it's what we

1 showed in our state analysis. Now you've got to go to E85.  
2 Then there was, well, we are going to need a much more  
3 significant infrastructure nationally to do that. So this  
4 was really to stave off when you would reach the blend wall.  
5 But even for that sake of argument, going to E15, you still  
6 delay the inevitable. You are going to reach the blend wall  
7 two or three years later anyway. So it doesn't prevent it  
8 over the life of the RFS2 obligation program, you just delay  
9 it a couple of years.

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

22 MR. SCHREMP: That's a very good question, Chairman  
23 Weisenmiller. In fact, like you said, back then the heavy  
24 diet of California crude available to them, the changing  
25 demands in the fuel qualities were such that refiners had to

1 expend a great deal of money to handle that difficult crude,  
2 both in the higher sulfur content and lower viscosity. So  
3 the California refiners, after spending billions, are now  
4 probably some of the most sophisticated refineries in the  
5 world.

6 But your other element about the changing mix is  
7 spot on. Because we just briefly touched on this in our  
8 2009 IEPR. But what is happening with the decline in  
9 gasoline demand because of the factors Malachi mentioned as  
10 well as the RFS2 overlay pushing it down further, what's  
11 happening to diesel and jet fuel over the same period?  
12 Well, they are not declining, they are continuing to grow.  
13 So what you have now is refineries cooking the crude oil and  
14 what comes out in various proportions is based on the  
15 equipment. There is some limited flexibility in how they  
16 can modify that.

17 So simply put you could have a situation where the  
18 California refining complex starts to look a lot more like  
19 another place on earth, Europe. So what happened in Europe?  
20 Because of taxation policies favorable to diesel you saw an  
21 increasing demand for diesel, rather aggressive, a  
22 flattening of gasoline demand. And now the European  
23 refineries are saying, I need diesel, more than I can make  
24 and, oh yeah, I have a bunch of gasoline for sale. So what  
25 happened in Europe is the United States gasoline demand was

1 continuing to grow. The Northeast of the United States is  
2 short on refining capacity, they import two-thirds via  
3 pipelines primarily and across the water. So a cargo of  
4 diesel - higher demand, higher market clearing prices there,  
5 attractive for the United States - went to Europe, emptied  
6 that cargo, filled it up with gasoline and components and  
7 sent it back. Back and forth, back and forth across the  
8 pond. That works well.

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

20 So we believe that that might be a challenge for  
21 them. We don't have their production cost numbers. But we  
22 look at different things. For example, one of the refiners  
23 that publicly shows their quarterly information, shows  
24 production costs in various regions, and you see that the  
25 California facility has double the production cost of these

1 other regions. Most recently BP's intention to sell some of  
2 their refining assets in the United States, and even in  
3 their pronouncements as part of that sale, were, well, we  
4 are keeping some of our better performing refineries -  
5 Indiana, Cherry Point in Washington State - and we are  
6 selling BP in Southern California and Texas City.

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

16           CHAIR WEISENMILLER: Thanks.

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

1 report?

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

16 MR. OLSON: Okay, thank you.

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

19 (No response.)

20 MR. WENG-GUTIERREZ: So just to end the day I just  
21 had a slide about next steps. It's basically that we are  
22 going to be finalizing the inputs into our model, taking  
23 comments from today and comments that we will receive in the  
24 comment period, and then finalizing our inputs into our  
25 demand forecast. We will be holding, as we mentioned

1 numerous times throughout this workshop in plugging our next  
2 workshop, a transportation energy infrastructure workshop in  
3 May, May 11th is I think our tentative date. And we hope  
4 that people participate in that. Certainly we will be  
5 talking about a number of important issues that I think will  
6 hopefully address some of people's questions that were  
7 raised today.

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

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

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

6 (No response.)

7 All right. Anybody on line?

8 (No response.)

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

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

14 (Adjourned at 3:55 p.m.)

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## CERTIFICATE

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

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Michael F. Connolly, CER  
Reporter/Transcriber

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Date