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	)	Docket No. 13-IEP-1L
2013 Integrated Energy	)	
Policy Report	)	RE: Electricity, Natural
(2013 IEPR)	)	Gas, and Transportation Demand
		Forecast Inputs

LEAD COMMISSIONER WORKSHOP ON
ECONOMIC, DEMOGRAPHIC, AND ENERGY PRICE INPUTS
FOR ELECTRICITY, NATURAL GAS, AND
TRANSPORTATION FUEL DEMAND FORECASTS

California Energy Commission
Hearing Room A
1516 9th Street
Sacramento, California

Tuesday, February 19, 2013
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Reported by:
Kent Odell

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INDEX

	Page
Introduction	
Suzanne Korosec, IEPR Lead	4
Opening Comments	
Lead Commissioner Andrew McAllister, CEC	4
Chair Robert B. Weisenmiller, CEC	9
Commissioner Michel Florio, CPUC	10
Overview and Summary of Coordination Activities	
Ivin Rhyne	10
Natural Gas Assessment - Key Drivers	
Leon Brathwaite	22
Economic and Demographic Assumptions	
Chris Kavalec	74
Retail Electricity Prices and Other Assumptions	
Malachi Weng-Gutierrez	111
Transportation Energy Analysis - Key Elements	
Tim Olson	137
Zero Emission Vehicle Mandate Update	
Gerhard Achtelich, California Air Resources Board	150
Crude Oil (Petroleum Fuels) Price Assumptions	
Ryan Eggers	158
Adjournment	176
Reporter’s Certificate	177
Transcriber’s Certificate	178

1

P R O C E E D I N G S

FEBRUARY 19, 2013 10:11 A.M.

COMMISSIONER MCALLISTER: All right, so I want to call this IEPR Workshop to order and kick it off, well, I'll just say welcome, this is the first Commissioner workshop in this cycle of the IEPR for 2013; it's a pleasure to have you all here. Feel free to move up to the front row, don't be shy.

And with that, my name is Andrew McAllister, a Commissioner here at the Commission. Chair Weisenmiller is with us. And I would also welcome CPUC Commissioner Florio, who we're very fortunate to have with us here today. This is a really important topic and I'm looking forward to digging in to the details and appreciate all the hard work of staff having put it all together. So, I'll pass it off to Suzanne Korosec.

MS. KOROSEC: All right, good morning everyone. I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit. So welcome to today's workshop on Economic, Demographic, and Energy Price Inputs for the CEC's Electricity, Natural Gas, and Transportation Fuel Demand Forecasts.

I do want to especially welcome Commissioner Florio, who was kind enough to make the drive from the Bay Area to join us today.

As Commissioner McAllister said, this is our first Lead Commissioner workshop under the 2013 IEPR Proceeding, but we have already had two staff workshops, one in October on Forms and Instructions for Data Submittals, and one in late January on California's Economic and Demographic Outlook.

A few quick housekeeping items before we begin. Restrooms are in the atrium out the double doors and to your left. Please be aware that the exit door near the restrooms is for staff only and will set off an alarm if you try to leave the building that way. There's a snack room on the second floor at the top of the atrium stairs, under the white awning, for coffee. And if there's an emergency and we need to evacuate the building, please follow the staff out of the building to Roosevelt Park, which is kitty corner to the building, and wait there until we get the all clear signal.

Today's workshop is being broadcast through our WebEx Conferencing System and parties should know that you are being recorded. We'll make an audio recording available in a couple of days on our website and a written transcript will be posted on the website in about two weeks.

We plan to break for lunch around noon and we've set aside time at the end of the day for public

comments. During the public comment period, we'll take comments first from those of you here in the room, and then we'll follow it up by people on WebEx. When you're making comments or asking questions, please come up to the microphone at the center podium so that people on WebEx can hear you, and so we capture your comments in the transcript.

It's also helpful when you come up to speak to give the Court Reporter your business card, so we make sure that we attribute comments to the correct speakers and that we spell your name right.

For WebEx participants, you can either use the chat or raised hand functions to let our coordinator know that you'd like to speak, and we'll either relay your question or open your line at the appropriate time.

We're also accepting written comments on today's comments until the close of business on March 5th, and the notice for today's workshop is available on the table out on in the foyer, and also on our website, and it describes the process for submitting comments to the IEPR docket.

Just some very brief context for today's workshop. An integral part of the CEC's biennial IEPR is our forecasts of future energy demand growth for electricity, natural gas, and transportation fuels. The

building blocks for those forecasts are the input assumptions, which obviously have a major impact on the results. This workshop underscores our commitment in the 2013 IEPR to coordinate assumptions across the various forecasts here at the CEC, and also to reach out to others to get the best possible inputs to improve the usefulness of the forecasts.

We recognize that there's a lot of uncertainty in any forecast, and one of our tasks is to strike a balance between reflecting that uncertainty and coming up with something that's useful to decision makers.

We also want to be very clear about our analytic approaches, our methods, and our inputs, so that everyone understands what's driving the differences between our forecasts and others.

So our agenda today is pretty straightforward, starting with an overview of coordination activities here at the CEC to develop consistent cases to be used in the three forecast areas. We'll then hear about key drivers for the Natural Gas Assessment, followed by our lunch break around noon. If we do get done with our natural gas presentation before noon, we'd like to open it up for public comment if there's time to do that, so that people that may not be able to stay until the end of the day can have a chance to make some comments.

After lunch, we'll have presentations on Economic and Demographic Price and Other Assumptions, and then move into the transportation portion of the agenda covering Transportation Energy Fuel Analysis, the Zero Emission Vehicle Mandate, and Crude Oil Price Assumptions.

We'll then have an opportunity for public comments and expect to adjourn around 5:00. We do have one slight change to the agenda. Ms. Bevan from the ARB is ill and unable to attend, and she will be replaced by Gerhard Achtelich.

We also have several workshops planned over the next few months on these topics, including a workshop on the Natural Gas Modeling Scenarios on April 24th, followed by a June 4th workshop with draft results of that effort; a workshop on Preliminary Electricity and Natural Gas Demand Forecasts that is scheduled for May 30th; and a workshop on Inputs and Assumptions for the Transportation Energy Demand Forecast on June 22th, followed by an August 7th workshop on the draft results of the analysis.

So we've got a lot to get through today, so I'll turn now to the dais for opening remarks.

COMMISSIONER MCALLISTER: Great. Well, thank you very much. I'm really looking forward to today's

discussion, as Lead Commissioner on the 2013 IEPR. A lot of meaty topics here not only today, but throughout the season here for the IEPR, and many of them, well, all of them are important, this one in particular I think is very critical to what we do with all the different forecasts. And we're very fortunate to have Commissioner Mike Florio from the PUC with us today, and definitely looking forward to his participation and input here, and in an ongoing fashion, as well, with the staff and Commissioners at the PUC.

The forecast is fundamental foundational work for us here in the state, everybody uses it, and it starts here with this process. So without further ado, I'll ask Chair Weisenmiller and Commissioner Florio if they have some opening comments, as well.

CHAIRMAN WEISENMILLER: Yeah, I was going to say that when you look at the IEPR pieces, I think the forecast is one of the critical ones in the sense that, by statute, other agencies are directed to rely upon it and at the same time it is a pretty awesome responsibility for the Energy Commission.

These are times of great uncertainty in the Demand Forecasts. When you look at the economy and you look at energy efficiency, you look at ZEVs, you look at climate change, and you look at all the pieces, there's

just, I think, much deeper uncertainty than we've historically had. And, so, we need to make sure that our forecasts certainly support a dynamic California economy, but at the same time that we don't over-estimate the forecasts.

And so it's a real tension to come up with something that reflects the overall uncertainty, but also comes up with a reasonable case for everyone to base their planning on. And again, I'd like to certainly welcome Mike Florio here.

COMMISSIONER FLORIO: Thank you. It's a pleasure to join you here for this important kickoff meeting. We do use the Energy Commission Load Forecast in many aspects of our work at the Public Utilities Commission, so I think it's important that we at the PUC have an understanding of the building blocks that go into it. And I'm looking forward to learning a lot today and having a greater appreciation for the difficult issues that you folks have to sort out. So a pleasure to be here.

MR. RHYNE: All right. So good morning, Commissioners, members of the public, stakeholders. My name is Ivin Rhyne. I'm the Manager for the Electricity Analysis Office here at the California Energy Commission and I'll be giving an overview of the work that we're

doing and the reasoning behind it in terms of developing these common cases and kind of why we're going in the direction we're going.

We're going to cover three basic topics today. First is just fundamentally what are we doing and why are we doing it to develop these IEPR common cases, an overview of the common case methodology and a short, a brief discussion without numbers, of some of the common case input assumptions.

Really, our focus here today is to talk about the connective tissue between each of these models. We're going to talk a little bit -- I'm going to talk a little bit -- about some of the limitations in attempting to do this work, as well as some of the opportunities that it presents.

So the first point I'd like to raise, actually it builds a little bit on what Chairman Weisenmiller was just saying in that any forecast has to deal with uncertainty. One of the uncertainties that we have to deal with in this is that the energy sector has become very large, very complex, and very interdependent. We could no longer talk about any one policy, or any one sector in complete isolation from the others.

Now, in this kind of large and complex world that we live in, this has kind of led to some fractured

analysis; it's led to having a little bit of a split personality disorder when you start talking to specific models. Partially this is because of the necessity of simplifying areas outside of the model and digging into the details that are within the modeling approach that you're working on.

Our work here is an attempt to connect together the expertise of different modelers from different teams, in a reasonable way, and so that we can move forward.

Primarily, we're building three cases that really are meant to easily translate across each of the energy sectors. This provides a stronger basis for policy discussions because we can say at the end of the day that, when I talk about the assumptions or the results from one model in this particular case, I can translate it to some extent over and look at how the results of, for example, the electricity sector, or the natural gas sector, reflect changes in the transportation fuels sector.

Now, fully integrated modeling, the kind of modeling that people think when you talk about perhaps one at the National Labs, or the Department of Energy, really require some vast resources, resources meaning both personnel-wise, and computing-wise, data-wise, all

of these things here, and that's not something that we're ready to jump into. We're not attempting to create this one model to rule them all type of approach.

Rather, what we're attempting to do is expand on coordination activities that were begun in the 2011 IEPR, where we started out with just some basic and common economic and demographic assumptions, and we're building a bit on that.

Now, in order to build these common cases, we need to define what it is we mean by a common case and define what we mean by high and low. If I say I'm talking about the high case, one modeling team might think I'm talking about high price, another might think I'm talking about high consumption, another might think I'm talking about a high penetration of renewables; it all depends, and so we need to be very clear.

The three IEPR common cases will be built around high and low energy consumption. This is primarily because our State policies around energy tend to focus on consumption activities, rather than price. And so we're going to be talking about high and low cases, but we're also going to be talking about a reference case, or business-as-usual.

This creates some interesting challenges because in order to model, in order to build a tool that looks

out into the future, we have to start with some assumptions about where we are today and where the values that we're going to be looking at are likely to trend out into the future. In other words, we have to have some starters, some seed values.

So what we're doing in this case is we're starting with two kind of updated pieces of seed information: the first, we're going to talk about recent natural gas production cost curves, and Leon Brathwaite of the Natural Gas Team is going to talk about some of the results that come out of that, which we've obtained from Rice University, one of the recognized experts in the field of estimating these types of costs; but we're also going to look at updated economic and demographic data that was provided as part of -- or I should say it was raised as a part of -- a workshop held by our Electricity Demand Forecasting group.

Now this is, as I said, just starter values and I want to be very clear about that because this is an extremely simplified version of how this process is going to work. Where we are today, we've used the Rice University Production Costs and the Updated Economic and Demographic Assumptions to start a first run, a very preliminary run, of the North American Gas model that

our team here runs and operates. This produces a set of natural gas quantities and prices that are then used as inputs to other models.

As you can see from this simplified graph, it goes into both the electricity demand and the transportation demand models. Now, again, those boxes are actually encompassing of a lot of work and a lot of different models, so, just for the sake of simplicity we've narrowed it down and compressed it all into a single box.

From the transportation model, those outputs are then used both as part of the electricity demand model, so for example the electric vehicle estimates and the demand required by those, but also by the North American Gas model, again, because they are also alternative transportation, things like natural gas powered vehicles.

The electricity demand is used in part by our electricity dispatch model to create an estimate of how much electricity is going to be served by natural gas and, of course, that value then feeds back up into the North American gas model. Now, as you can imagine, by the time that reaches back around to this beginning point, a lot of those values that the gas team may have started with have been changed and altered by the

various assumptions, inputs, and expert feedback that have been elicited by each of those independent teams. And so the gas team will then take that information, put it back in along with any updated information, and create another run -- or I should say another set of runs.

This is an iterative approach, it is not meant to converge everything down to a fully harmonious, and everything converges to a single value, because we don't have the time or the resources to do it. But it does allow us to begin moving towards that convergence. It begins to allow us to have outputs that are reasonably aligned, consonant, you can say, with the inputs and outputs of other models. Again, if we had unlimited time and resources, if we could build super computers in the basement, we might be able to get there. But for now, this is the way that the process is going to work. So this connective tissue, the areas between what do we share, what don't we share, is important.

So we start with some common input assumptions, some of which I've mentioned. We talked about Gross Domestic Product, the GDP growth, Gross State Product, the inflation rate, population growth, energy efficiency improvements, Demand Response, carbon prices, and weather. All of these inputs are easily shared across;

all of the models require them, and in a high consumption or in a low consumption world they all align generally, move in similar directions.

Now for these areas, there's no conflict, there's no reason to have to resolve anything, we simply agree on a value, we get feedback from stakeholders, and we share that value across models. But as you can imagine, it's never quite that simple for everything. There are some tradeoffs that we have to make because there are occasionally times when a high consumption world in one model was actually more consistent with a low consumption world in another model, or in another sector.

And so, when we do this, we have to figure out how we make a decision between which drivers -- which direction do we move that value? So we are using what we call the Major Driver Test. This is a relatively straightforward test where, if the natural gas sector, just as an example, uses an input value as its major driver, it is a critical piece of the model, as opposed to the other models which may see it as a minor driver, then the model that uses it is a major driver, is the one that wins the conflict. This allows us to get to outputs through some sort of a kind of reasoned approach, and allows us to talk about what this looks

like without having to make too many caveats.

So we did have some variables that required some resolution. So, for example, electricity price -- and I'll just use this one as a quick example -- as the electricity price goes down, obviously that's going to tend to have people want to purchase -- it'll make it more economically efficient for them to purchase more electricity, and so that leads to a higher electricity consumption world.

But in the liquid fuels world, a lower electricity price might also mean that people are more willing to purchase and use electric vehicles, which would draw demand away from those liquid fuels. At this point, electric vehicles are a relatively small minor driver in the larger world of liquid fuels, and so the electricity model in this case is the one that wins out.

Similar for natural gas price, crude oil price, electric vehicle penetration, coal price, and natural gas vehicle penetration, each of those -- the values selected for those -- are set by the model where it's a major driver.

When we get results out of this, as we work through these scenarios, these cases, the reference case talks about -- or should represent -- a reasonably expected trajectory given our best available input. And

the unspoken, unwritten piece there is following as many iterations and delineations as we could reasonably do with the resources we have. The high and low energy consumption cases represent a reasonable range, but they are not the most extreme cases. And that's precisely because of the tradeoffs we've had to make. They don't push the boundaries so wide precisely because in some cases we've had to narrow it back in order to align model assumptions between each of the different types of models.

This interdependence of the energy sectors and the choices that we have to make, as interesting and as difficult as it is, at the end is meant to provide us with a point where we can talk, again, across these sectors when we look at policy choices in the IEPR; we can have some at least reasonable understanding, a beginning place, to have that part of the discussion.

So our next steps following this workshop, we're asking for feedback from stakeholders. First, on the reasonableness of the approach; do you have concerns about how we're connecting the models? Are there particular areas where you think it requires more discussion, more iteration? Perhaps you are happy with it and we'd love to hear that, as well.

We want to refine the input case definitions.

Right now, they are broadly defined and we have some starter values that each of the modeling teams are working with, but we'd like to make sure that we've thought of everything and we certainly acknowledge that there are more -- there's far more fire power in the room today than we can bring to bear on any one problem, and stakeholder input is a valuable part of that process, so we very much appreciate feedback on that.

Each of the modeling groups will then begin building other scenarios as needed. One of the key things that I'd like to emphasize is that these three common case scenarios are not limiting to any of the additional scenarios that any division, or team, or modeling group will be working on.

Each area of the energy sector has some specific challenges, some interesting quirks, and some kind of areas where we want to explore thoughtfully something that perhaps isn't quite there in terms of the reference case or the high and low. We will in each of the individual workshops -- as Suzanne has pointed out, each of them has multiple workshops -- we'll be discussing those additional scenarios, so we're not limited in any way to these three common case scenarios. These are just kind of a point of connection between the modeling groups and an area where we can move on.

So at that point, I'm going to stop and ask if there are any questions from the dais.

COMMISSIONER MCALLISTER: So thanks, Ivin. I guess I would just make a request, really, that I think it's important that people -- many people in this room are experts in their own right in one area or another, but I think it would be good sort of foundational background information to understand the kind of origins and ownership of the models that are being used because I think they all have important histories, there's a reason why we're using these models, and yet they also have their own histories. So on the one hand it's a good thing because they're established in their own field; on the other hand, it does mean that they're unique kind of -- they don't necessarily fit together as you said, nice sort of puzzle pieces that just seamlessly fit together. So we have to come up with this connective tissue and that's what you're really talking about. So it would be nice as context if each presenter on staff, and certainly any of the experts in the room, could help us all understand how one particular model fits with the others, or doesn't, so we can flesh out this scenario-based modeling exercise and ask, you know, better questions along the way. So thanks.

MR. RHYNE: And we'd be happy to do that. Thank you.

MR. BRATHWAITE: Good morning, Commissioners, members of the audience. I am Leon Brathwaite. I work here in the Natural Gas Unit here at the Commission.

I will be presenting two things today. First, I will be looking a little bit at a brief background into our natural gas model; and secondly, we will also be looking at some preliminary results from the three cases that we have developed to date.

Now, I want to say that these cases are preliminary, and I mean that in every sense of the word, it is preliminary. We are seeking input both from the dais and from our stakeholders along the way.

Also in my presentation, we will look a little bit about the methodology of our natural gas model.

In previous IEPRs prior to this one, we used to run the World Gas Trade Model. That model is constructed in the Market Builder Platform that is presently owned by Deloitte Marketpoint. And Commissioner McAllister, you asked a little bit about a history of this model. We have been using the Market Building Platform for the last 10 years. In 2007, I believe, in the 2007 cycle, the Commission requested that we take a serious look at our modeling tools, in

particular the natural gas tool that we were using, the Market Building Platform at that time, and we spent some very serious time looking at that, looking at other models, GCPM and another model whose name I can't remember at this point in time, and compared them to the performance of this platform that we've been using. And after deep consideration, we decided that we would stick with the Market Builder Platform. And so far we believe it works reasonably well. However, Commissioner, at a future date off line if you wish, I can certainly give you a little more background and history about that particular model if you so request.

So anyway, in the previous cycles, we were running the World Gas Trade Model, and the model is constructed in the Market Builder Platform. But we decided that we would start to focus only upon North America. The World Gas Trade Model is very cumbersome in the sense that both data and the associated structure is quite a task to manage. So we decided to focus on North America, this is U.S., Canada, and Mexico. And we constructed what we are now going to call the NAMGas Model and, of course, NAMGas is also built in Market Builder.

So what did we do to get to NAMGas? We started with the World Gas Trade Model as we have in previous

times, and we reconfigured the California portion of the model to see what the Energy Commission needs. We added functional nodes to account for liquid natural gas, imports and exports, removed all non-North American structure, and then we added nodes to deal with the transportation sector, the natural gas demand for transportation. Those nodes, demand for transportation, is small but certainly a growing and important sector in our economy. And as a result of those changes, we brought about what we are now calling NAMGas.

So if you're going to look inside -- let's talk about what's going on inside of the model. The very first thing that we have to do on the supply side of the model is that we have to estimate recoverable reserves and those are technically recoverable and economically recoverable reserves. Now, the economically recoverable reserves are really a subset of the technically recoverable, and what economically recoverable reserves tell us is at what cost are we going to be able to recover these things.

Now, the prices -- these reserve estimates change with technology and changes of price, and they are one of the very most important input parameters into the model. We will develop as a result of this exercise, develop what we call Supply Cost Curves, and

I'll be showing that here in a little while.

So here we have a demonstration, a schematic that shows one of our supply regions, and we have two sets of nodes on the supply side that are of great importance in the model. We have the green nodes which we call depletable resources; that is, these depletable resources require -- there is a very active investment logic on these nodes, and this is the process of drilling and production that is ongoing, that is represented here in our model. So in order to produce resources, or to produce any sort of supply from the green nodes in the model, we must have capital expenditure and we must have operation and maintenance costs.

We also have the brown nodes. The brown nodes we call simple supply, and we put all of our proved reserves, the reserves that we have some fair, high confidence in, we put those on the brown nodes and they only require operation and maintenance costs for production purposes. There are some other nodes in here and I will be talking about them as I go through this presentation.

Here we have a demonstration, an example of the supply cost curves within the model. Now, in 2007, this was our supply cost curve. In 2011, this is what it

looks like, the red line. In 2013, here we have a supply cost curve out here. So what we are seeing here is that technology is shifting the marginal cost curve, the marginal cost profile. So overall, what is happening is we are having more resources available at lower costs. What we are seeing really and truly is the effects of technology. Technology is shifting the curve and shifting it to the right. And I guess we know the story about the development of shales, and this here is representing that movement to the right with the development of the shales.

On the demand side, let's talk about that for just a second. Now, the model requires some start in values, and I say start in values because we are just starting with them, and as the model goes through its iterations, the starting demands will change as a result of the price changes, as a result of the elasticity estimates that we do input into the model.

So the first thing that happens, though, is that we must estimate these starting reference quantities and start in reference prices. We do have an Excel-based econometric tool; we sometimes refer to that as a small "m" model. We use historical data to calculate in the shale prices and quantities. These things are then loaded into the NAMGas Model, and then the model can run

and does all its iterations, and then we'll get some results out and we'll look at it and decide if we'll accept it, or not. But the process requires us to do an regression analysis to estimate both the quantities and the elasticities. And each one of these regression analyses has a bunch of independent variables for the five disaggregated sectors that we have on the demand side. Our five disaggregated sectors are residential, commercial, industrial, oil generation, and we just added transportation in this cycle, we didn't have transportation broken out previously, but we do now.

So what are the independent variables in each of these sectors? On the residential side, we have recent historic demand for natural gas, population, natural gas prices, income, heat and oil, and cold weather. For commercial, we have recent historic demand for natural gas income, natural gas prices, population, heating oil and cold weather. For industrial, the independent variables are recent history, recent historical demand for natural gas, natural gas prices, coal prices, industrial production, which is a very very important variable here, and cold weather. On the power generation side, we have total electric generation, weather, natural gas prices, fuel oil, renewable electric generation, and coal prices.

In transportation, on the transportation side, again, recent historical demand for natural gas income, natural gas prices, population, heating oil, and cold weather.

We put all of these things together in our regression analysis. And using that regression analysis, the output of that, two things, the elasticity estimates for each of the sectors, and an array of starting -- and I want to underline the word "starting" -- an array of starting demand quantities that we will end up putting into the NAMGas Model. But in general, high rates of demand growth influences the flows and prices within the NAMGas.

So here we have the schematic that I showed you previously. These here are tombstones; this is where all our demand is located in the model. All the reference quantities and prices start there on these nodes. The tombstones are price responsive, they are elastic demand nodes; that is, as prices change endogenously, the demand will also change. And this is one of the great things about this model, that it responds to price changes as we do in the real world, we are trying to replicate that here. And if ever you want to think about the tombstones here, think about it as the place where natural gas goes to die -- that was a

joke.

There are some other parameters that are important such as what we call gas substitutes or really a backstop price, or a backstop resource. But what is a backstop resource? Let me explain that a little bit. As prices rise in the real world and in the model, new resources are coming into play. Now, if the prices rise high enough, new technologies will come into play. So we have assumed in the model, we do not have a specified technology that will come into play if prices rise high enough, but what we do have is an unspecified technology, but it is priced at $9.00 per McF, that if prices were to be sustained at that level, then we would have this new technology coming into play within the model.

There are also policy parameters. And policy parameters are very very important. One good example may be, for instance, there are some natural gas resources that are in environmentally sensitive areas, and as a result its development has been restricted, and we can reflect that in the model. So if, for instance, right now in the state of New York, the Marcellus shale is not being developed because of some of the issues involved in the watersheds, and the development has been restricted and, in some cases, is probably going to be

banned forever -- we don't know that yet, but it may be the case. We can reflect that in the model by turning off that resource; it will be physically in the model, but it will not be allowed to flow even if it is economical to do so, the policy restrictions may cause it not to, and we can reflect that in the model.

Some of the other things that are in the model, key variables, investment parameters we have in there such as rates of return, royalty rates and taxes are also present in the model. We also have to deal with the assumptions regarding the timing and availability of certain resources and infrastructure. And this goes back to the policy issues to some extent, but not quite, this is a slightly different issue.

In 2007, say for instance when we were doing our own analysis, we physically had within the model the Ruby Pipeline; however, Ruby did not start flowing until I think around 2011, so when we were doing this analysis in 2007, we could turn off, at least delay, any flows along Ruby until we think it was going to actually do so. Well, it turned out that it didn't start flowing until 2011. But when we are doing this analysis in 2007, we might have turned it off until 2010 or something like that. But the point is, though, we have the ability to either ban within the model a flow from

occurring, or prohibit it completely, or delay it, postpone it for a certain length of time. And this is where we get to this assumption regarding the availability of resources.

One other thing that we must do is put the model, the world of the model, in a particular cost environment. Now, one of the things that we don't want to do is to put the world of the model in a high cost environment as we saw here in 1979 through 1984, nor do we want to put it in a low cost environment as we see here in 1992 all the way to 2000. What we are looking at here is a year-to-year relationship of real cost through time. We are attempting, since we are in a long-term model, we are attempting to come up with a typical cost year -- real cost year -- and those years will get from a P50 line, which is right here, and those years that we have selected is 1975, 1986, and 2003, we are looking for a typical cost year, we don't want a high one, we don't want a low one, okay? We'll talk about this graph a little bit later on to show how we can develop scenarios using some of the parameters in this graph. But in terms of the reference case, we are trying to get a typical cost year that we can use, that we can use real costs, and use that in our model so that we do not bias the results in one direction or another.

So now I would like to get into the results of some of the cases that we have developed to date and I must emphasize this: these are preliminary cases. We are looking for input from all stakeholders involved in this process, we are looking for input from all Commissioners, from any member of the audience, if there is anything that you see that looks, you know, unpalatable, shall we say, please, we really want to hear about it.

So what we'll be doing over the next few slides, 1) we'll talk about the purpose of the preliminary scenarios, and we are calling them "scenarios" or "cases"; we'll talk about -- we will name those preliminary scenarios -- we will describe them, tell you what was changed, what did we do. We will look at the general impact of price changes, we'll briefly talk about the price performance of some of these cases, these scenarios, and then we'll talk about a reconfiguration of the supply portfolio as price changes because that is a very very big deal, and we'll talk about that here shortly.

So what is the purpose of doing these scenarios? Well, we have several purposes, 1) we are trying to examine price and supply in the national natural gas market, in the national natural gas market. But within

that, within that, we are looking at potential vulnerabilities to California and we are looking at potential opportunities for California.

We also want to investigate natural gas price and supply uncertainty, and this is a very very big deal. Gas prices have been coming down significantly over the last two or three years without a doubt, but we have also experienced at sometimes some very high gas prices. I think in 2008, we had gotten up to somewhere in the $12.00 or $13.00 per McF. So what we are trying to do here is to try to capture that range of uncertainty and volatility that we have seen out there. We also want to develop plausible outlooks of price and supply.

But the question that we are really and truly trying to answer when we look at some of these scenarios is what happens if we have the "Perfect Storm." And when I use that word "Perfect Storm," we are asking the question, what happens if all of the outputs, all of the events associated with high prices, what happen if they were to occur simultaneously? And this is what I'm calling the "Perfect Storm." Or what if all events associated with low prices were to occur simultaneously? What happens then? We are trying to investigate this.

Further, we are trying to investigate the impact

of relevant policy, and there are some big ones that are ongoing, 1) the implementation of the Renewable Portfolio Standard, 2) conversion of coal-fired generation, 3) any environmental mitigation as a result of shale development, in particular the use of water in hydraulic fracturing and the disposal of that water. Also, the licensing of LNG export capability, we certainly want to be able to say something about those matters.

But I want to be clear about something. We are not trying to predict anything here, we are not. What we are trying to do, however, is to provide insight to policy makers about the role of natural gas and its future in the supply portfolio. Are we yet ready to provide such insight? No, we are not. That's why we are here. We are seeking input. We are seeking any sort of input that will allow us to better able answer many of those questions that have been posed as we move away from natural gas into using more of our renewables for generation purposes.

So what were the cases that we constructed? We constructed our reference case, we constructed a high price/low consumption case, and we constructed a low price/high consumption case. Now, these three cases are the common cases which Ivin spoke about a little while

ago. And I want to say that a reference case as it is right now is not a most expected outcome, it is, shall we say, maybe business-as-usual. But we will be working with that case some more and we have many refinements that still must be done.

So let's talk a little bit about what we have in the reference case. In the reference case, we started our starting demand quantities -- in the reference case our starting demand quantities, and this is from all regions, all sectors, we have about 90 regions in the model in North America, and we have five sectors that I outlined a little while ago. So our initial starting demand quantities in 2011 were 22.1 TcF; for power generation it was 7.5. In 2020, we have a total of 26.9 TcF, power generation was .9 TcF. In 2030, the total is 26.2 TcF, and power generation was 10.6 TcF. Now, these are the starting values. Once the model goes through its iterations, as prices change, as it takes into account the effects of its elasticities, these will not be the values that come out of the model, and they will differ, and sometimes differ significantly from their starting inputs.

So we did estimate the elasticities with the help of Dr. Ken Medlock of Rice University, we did estimate these elasticities in all five sectors,

residential, commercial, industrial, power generation, and transportation. And a range of elasticities are 0.0007 all the way to 0.0653. So that is in our reference case. Also in our reference case, we assume that 30 GW of coal will be converted starting in 2014 -- not all of it will be done in 2014, but the process will begin in 2014.

The Renewable Portfolio Standard, we assume that California will meet its standard on time, and we assume that in all of the cases that California will meet its Portfolio Standards on time; however, we have delayed implementation of the standard in all the other states, we delayed it by five years. Now, there are some people who question that assumption, and we understand that, but we will be looking at this as we go through this process.

Now that was demand side. Let's talk a little bit about the supply side. Proved reserves are about 325 TcF. The potential reserves, 1,462 TcF at about $10.00 per McF, 1,280 at $5.00 per McF.

We also have some parameters such as investment parameters for resources. We expect a return of 12.2 percent real for pipeline; it's about 8.4 percent real. Income tax rate, 35 percent return on royalty -- on equity, my apologies -- is 8 percent. Backstop

technology, I spoke about that a little while ago, it's an unspecified technology at $9.00 per McF.

And the technology factor, we assume that technology is growing at 1 percent per year. Some people believe that that is low. We really would like to get some input on that value in the reference case.

We also constructed a high price case, or low consumption case. In this case, we converted 80 gigawatts of coal-fired generation. We assume that economic activity, the economy, will grow sustained at 3.5 percent. We delayed implementation of the RPS in all states other than California by 10 years. In California, we assumed that it will be met on time. Starting in 2016, we assumed that we will have robust export of LNG from the lower 48.

Also in this case, we did assume some environmental mitigation for the development of some of the resources, so we added a cost of $.40 in the development of shales; this is $.40 on the operation and maintenance costs, $.20 to conventional resources per McF in their development. We also shrunk the resource base by turning off some resources in New York and the Rocky Mountains, Colorado and Wyoming. Some of these resources, well, all of the resources that were turned off are in environmentally sensitive areas and we wanted

to see what would happen if these resources never come into play in the supply portfolio.

So at the end of the day, we end up with a supply cost curve that looks something like that. Now, I just want to be clear about this. This curve that you're seeing here, like all the curves I've shown to date, they do not appear anywhere in the model; what does appear in the model is about 200 curves in each one of the producing basins that are represented in the model. Even some of the basins we may have multiple curves for different zones within the basin. What you are seeing here is really and truly an aggregation of those 200 curves, and that is what you are looking at here. I didn't want to bore you by showing you 200 curves this morning, you probably would have fell asleep anyway, but anyway, that was a joke. So this is an aggregation.

Now, in our low price case, our low price case on the other hand, we converted one Gw of coal fire generation, we assume that all states -- California and all of the other states -- they meet their RPS targets on time. Economic recovery, economic growth is weak in this case, it's 2.1 percent. We do not allow any LNG to flow, exports to flow. We assume technology will develop at a rate of 2.5 percent. And here, we expanded

the resource base by 5.3 percent. We did that by finding credible sources of estimates of the various recoverable reserves in the various basins, and we used the upper values, or the upper ranges of this data to come up with this 5.3 percent expansion of the resource base. After we had done all of that, we end up with the supply cost curve that looks something like that.

This schematic combines the three curves that I've been showing previously in the previous slides. So the red here is the high price case, the high price/low consumption case; the blue, that is our reference case; and the green that is our low price case. So what we have done is that we have turned off some resources, we have turned on others, we have used certain different values to estimate the recoverable reserves, and we end up with a series of curves that look like that for the individual cases that we have done to date.

One thing that I would like you to focus on is this lower portion here of the curve. This raises an issue that I will explore a little bit later on in my presentation, and it's a very very important issue, but we'll talk about that as we go along.

So let us talk about the general impact of price changes. Generally, when prices rise, higher prices, it depends to depress demand, but it stimulates its supply.

On the other side of the coin, when prices fall, it tends to stimulate demand, but suppress the supply. Usually, though, when prices change we have some combination of this impact occurring, so there's usually some sort of dual impact which is very difficult to discern, which is, what is going on? And what is the dominant effect?

But what we know does happen, and we know this for sure, is that it does reorder -- it does reorder the supply portfolio because some resources become attractive, more attractive, and others become less attractive, and producers and demanders of these resources will take their resources from different places, depending on the price incentive. So the question that we are trying to answer when we look at the performance of these cases is, what is the dominant effect? Sometimes it is very difficult to discern that, but we're going to try to do this.

So, let's talk about the performance of the cases. And again, these are preliminary cases, okay? We are seeking input. I don't know if I can say that enough.

So this here, this schematic shows us the prices at Henry Hub for three cases, and we can see all three lines running in parallel, more or less, the high is

behaving as expected, it's higher than in most places, than the other cases, the lower is lower in nearly all places; and the reference case runs in the middle. But there are two things that are evident from this schematic, 1) the zone of uncertainty, which is the difference between the high and the low, is very narrow. And this is something that we will be working on. But if you do recall, a little while ago I showed you the three supply cost curves that we developed for the cases and, at the lower portion of that curve, there is hardly any difference between the three. This is being reflected in the narrowness of that zone of uncertainty. This is something that we'll be working on as we go through this process.

The second thing that is evident here is this seesaw effect that we are seeing only in the high case. Now, I should say it's the most evident in the high case because, when you really look at all the other cases, the prices do jump around a little bit, but it's most evident in the high case. If you remember, one of the inputs of this, one of the inputs in this case, was that we allow LNG exports, at least we forced LNG exports.

So two things are occurring there, 1) we are having significant development of shale, and that tends to depress prices a little bit there as we saw

initially. But further, as demanders of export LNG, as they demand more and more of exports, more LNG to be taken out of the domestic supply, it tends to push prices up, and this is exactly what we are seeing here, that prices are being pushed up because more and more people are demanding LNG for export. And then, when prices rise, the cycle starts all over again -- more shale resources come into play, and then prices fall, and then the process begins before we see some sort of leveling out of the high price case.

So we do have a zone of uncertainty, there is no doubt about that, but it is very narrow. The question that we have is, is it reasonable? Our feeling at this point in time is it is not and we should take some steps to try to fix that. Well, I don't know if that's the correct word, to "fix," but we'll take some steps to change it, shall we say?

The next thing we should look at is the price differentials that we are seeing. Early in the forecast horizon, we saw a differential, and this is Topock minus Henry Hub, we saw a differential that was negative; that means the California border prices were lower than that of Henry Hub. But as we go through the forecast horizon, we notice that there is a decided change to where the differentials are now virtually all positive.

And you may ask why, why is this occurring? Well, the reason is the following: if you were to take a map of the lower 48 and you were to look at where development of shale is presently ongoing, look at a Marcellus, look at the Eagle Ford, look at the Haynesville, look at the Woodford, all of the -- the Barnett shale -- all of the major shale development is occurring in the eastern part of the United States, not exclusively, but the vast majority of it is. So what is happening is the development of shale in the east is suppressing prices more than it is suppressing prices in the west. And as a result, we are having this flip of the differentials.

So let us talk a little bit about the supply portfolio. So we have two main demands in the lower 48, two, the end use demand on exports, and that has been satisfied by Canadian imports, lower 48 production, and a little bit of LNG imports. So the demand in the Lower 48 is about 73.6 BcF a day, and the exports, which is also a demand, a lower 48 demand of natural gas, is running about 8.4 BcF a day. How is that being satisfied? 1) Canadian imports, about 13 BcF a day, 2) lower 48 production, 72 BcF a day, and 3) we have a little bit of LNG coming in here, about .25 BcF a day.

Now, the question then becomes what happens to the portfolio when prices change? Now, this is for

2025, I could have chosen another year, I just happened to choose 2025. When prices rise, in 2025 in the high price case, prices rise about 12.3 percent. Now, end use demand drops off about 5.5 percent, but notice exports increase significantly. Export is a demand, it increases significantly, almost a third. But this was a case where we forced exports to occur -- LNG exports to occur. So what is happening? Canadian imports drop off about 8.5 percent; lower 48 production drops off about 1 percent; LNG imports not very large, not a whole lot of gas we are talking about here, but it rises about 156 percent. That is because the higher prices in the lower 48 are attracting a little bit more LNG. So Canadian imports come in now at 11.9; production, lower 48 production, comes in at about 71.3; LNG imports about 6.4 BcF, and that is serving the oil demand of about 70 BcF in the lower 48, and serving the export market about 11.1 BcF per day.

On the low price case, prices fall by about 7 percent; end use demand increases about 1.5 percent; export drops off about 22.6 percent, almost 23 percent. What that means is that a lot more gas is remaining at home because of the drop off in exports.

So Canadian exports drop off by about 2.3 percent, lower 48 production relatively unchanged, but

it drops off by 1 percent, and LNG imports drop off by about 60 percent. Now, as you would expect, of course, the lower prices is giving a disincentive for LNG to come into the lower 48.

So Canadian imports are coming at about 12.7; production is about 71.3; LNG imports is down to .1, and that is feeding oil demand of 74.1 of lower 48 end use demand, and feeding the export market about 6.5 BcF per day.

But the main point, the main point out of all of this that we are seeing is that when prices change, whether they go higher or they go lower, when prices change we are seeing the reconfiguration of the supply portfolio. This is what we are seeing here as prices change.

Let us look a little bit about California; the changes are not so very much evident in California because California is just a subset of the North American market. But I will try to -- let's give a little bit of background here on California itself.

Here we go. As you can see, again, we have that very narrow -- this is Topock prices -- we have that very narrow, very very narrow zone of uncertainty. Again, we see that seesawing effect that we saw previously and it is evident here in California. But,

again, the narrowness of this zone of uncertainty is a direct result -- is a direct result of the supply cost curves that I showed you a little while ago, where we are not seeing very much difference in the lower portion of the aggregated curves.

So what is happening here now? Here as a reference case we have end use demand and that end use demand is being satisfied by Canadian imports, Rocky Mountain supply, Southwest supply, and local production, that is, production within California. We have imports coming in from the north, 2.6, 2.7; Rocky Mountain is about 1.3; Southwest about 2.3, 2.4; lower production is about 2.1, satisfying a demand of about 6.4 BcF a day. One of the things that we should mention here, we did not -- well, as you know, California production and state production is dropping off and it's dropping off significantly. We did not assume anything about the development of the Monterey/Santos shale; we did not assume that in this analysis, in none of the cases. Now, the production trajectory of California production may change if that shale is ever developed. We did not assume that in any of these analyses.

Okay, in the high price case, prices rise about 9.9 percent; end use, a drop of about 3.4 percent; Canadian imports come in at about 2.5; Rocky Mountain is

about 1.6; Southwest about 2.4; in-state production about .25; and demand that is being satisfied is about 6.2 BcF a day.

On the low price case, prices fall about 4.3 percent, end use demand is relatively unchanged, and if you look at the price differential, there wasn't very much in between the reference case and the low price case.

We will be posting a corrected slide. These numbers need to be refined and probably corrected. But in the low price case, Canadian imports are about 2.6; Rocky Mountain is about 1.3; Southwest is running about 2.2; production in-state is about .36; and demand that is being satisfied is about 6.3 BcF a day.

Again, what we are seeing as I have said before is that, as prices change, we are seeing a reconfiguration of the supply portfolio. But one of the issues that have come up again and again, and this came up last time also when we had our 2011 IEPR cycle, was this issue about a narrowness of our zone of uncertainty. And certainly it is narrow, and certainly it doesn't truly capture the true volatility in prices that we are seeing in the marketplace.

So the question then becomes is there something that we can do to try to change that? Now, we do not

want the zone of uncertainty to be so wide that it is meaningless, that we could discern no information from it, it will be useless. But we want something that is reasonable, something that we can use to make decisions about any sort of policies that we may wish to institute in the State of California or nationwide if that is the case.

So what we have here, what we can do is we can combine two parameters, the reserve estimates and the cost environment, to try to see if we can push the limits of the extreme. We may not go to the extremes. The extremes may be implausible. But we can certainly head in that direction.

So the reference case that we have at this point in time is right here, that little gray area here -- right there. If we want to push a high extreme say, for instance, we can head in the direction of that box in the upper right-hand corner where proved reserves will be 325 and nothing else, and we will have a cost environment that is a high cost environment, okay? Maybe 1984 prices, 2008 prices, that kind of stuff. So we can go up into the right-hand corner -- that will be low estimates of reserves, but in a high cost environment.

On the other side of the coin, if we want to go

to the other extreme, we can go into a low cost environment with an extreme amount of reserves, and that will take us into the lower left-hand corner. Now, as I said, going into those extremes may be implausible, but in terms of opening up or widening the zone of uncertainty, we can certainly head in those directions to get a more reasonable range for our price outcomes.

So this is what we will be looking at, and this is what we are seeking some input on. Now, there are also other cell blocks in here where we can do different combinations and come up with different price outputs, and we can all look at those things and examine those things as the stakeholders and our Commissioners give us input, they can give us some idea of some other cases that they may wish us to run.

In conclusion, plausible national scenarios produce a wide range of price and supply outcomes. Price changes can and do reconfigure the supply portfolio. To integrate renewables into the generation supply portfolio, California needs a robust natural gas supply base. The switch from coal-fired generation may lead to higher natural gas demand.

Plausible scenarios can produce a zone of uncertainty; however, the abundance of shale resources keeps that zone of uncertainty relatively narrow, as

I've shown in some of the schematics here.

That brings me to the end of my presentation. But before I turn it back to the dais, Commissioners, I wish to acknowledge the work of some of the people who were instrumental in putting this analysis together. First and foremost, Dr. Ken Medlock of the Baker Institute in Houston, Texas. I would also like to acknowledge some of my colleagues in the Natural Gas Unit, Peter Puglia, who is in the audience, Robert Kennedy who is also in the audience, Paul Deaver is no longer in our unit, but I would also like to acknowledge his efforts, and last but not least, I would also like to acknowledge the efforts of Angela Tanghetti, who did help us in linking up natural gas and electricity. With that, I am done and I will now turn it over to you and the audience for any questions that you may have. Please don't make them too difficult. No, that's a joke. But, yes, I'll now take any questions or any comments that you may have. Thank you very much.

COMMISSIONER FLORIO: I don't think you're using -- you're not looking at any external shocks to the system like hurricanes, well freeze-ups, exceptionally cold weather, things like that that might cause short-term spikes in the price. Is that correct?

MR. BRATHWAITE: Commissioner, that is

absolutely correct. Now, this model is a long-term annual model, so you are right, we are not looking at shocks to the system. Now, we are in the process, and I do not believe it will be available for this IEPR cycle, but we are in the process of developing a short-term model where we will be looking, I think, on a monthly basis and we will be able to more address that issue when we do have that model up and running. But we hope to have that up and running before the end of the year, but we will not have it available for this IEPR cycle, but you are absolutely correct about that, sir.

COMMISSIONER WEISENMILLER: Hi. A couple of other questions. On page 17, you give a range of elasticities. I'm assuming those are associated with various sectors?

MR. BRATHWAITE: Yes, sir.

COMMISSIONER WEISENMILLER: Could you describe which sector the low and high elasticities are associated with?

MR. BRATHWAITE: The low, I believe, is associated with the residential sector because, you know, demand doesn't change very much there. And the high, I believe, is the industrial sector, Peter? Could you remember? Commissioner, at this point in time, I am not really certain as to where -- I'm certain about the

residential sector in terms of on the low, the high I am not sure about, but I'll be happy to provide that information for you at some point in time?

CHAIRMAN WEISENMILLER: That would be good. If you could just put in the record the elasticity for each sector, that would be sufficient in supplement.

MR. BRATHWAITE: Okay --

CHAIRMAN WEISENMILLER: My other question was my recollection was that PG&E uses the same model?

MR. BRATHWAITE: Yes, sir. That is correct, yes.

CHAIRMAN WEISENMILLER: And last time I thought there were a lot of questions that came up near the end in terms of differences in the assumptions, so I guess I was going to encourage more of a dialogue with PG&E earlier on what the differences were. Obviously, it's a complicated model that I guess has thousands of assumptions --

MR. BRATHWAITE: Yes.

CHAIRMAN WEISENMILLER: -- seem to be -- at that point everyone threw of up their hand trying to line things up better. But I don't know if PG&E has any sense of what the major differences are on, again, how we can try to make some progress on --

MR. BRATHWAITE: You, well, you know,

Commissioner, to be honest, usually the differences has to do with the data that we put into the models because, structurally, between us and PG&E -- and we have worked with PG&E in the past -- structurally between us and PG&E, there's usually not much difference between the two models. But usually it's something -- the differences can be about of what we assume, sometimes we have had differences on the elasticities assumptions, we have had differences there. We have also had some differences in terms of what we assume in terms of rates of return in some of the pipeline capacity additions. So usually it's a data issue that, of course, the differences between us and some of the other people, we use the same model. But, yes, you are absolutely right, sir, we will be working with as many people as possible and try to understand those differences. If they can be reconciled, we will reconcile them; if not, at least we are aware that they do exist.

CHAIRMAN WEISENMILLER: It seems like the dominant variable is the resource shapes or curves there and particularly the shale. And to the extent you have a relatively flat and a relatively, you know, that that seems to be what drives a lot of the narrowness. And so part of this is just trying to understand if, again, between we and PG&E, if those are the drivers, or indeed

it's more of some of the elasticities, or some -- obviously you can have much different linkages in the pipeline system being emphasized or deemphasized. So, again, just trying to -- but I assume the major thing to understand is, if the resource shapes are similar, then again that would give us more confidence in the sort of underlying results we're getting.

MR. BRATHWAITE: Absolutely, sir. And you are absolutely right, the supply cost curves, the resource curves are one of the most important, if not the most important, input into the model. And certainly it is something that we should focus on and make sure we have a full understanding about what we are using in-house and what other people are using in their analysis. So we will certainly try as much as possible to reach out to other users of this model, PG&E and others, to try and have some understanding of that. And we will certainly update you, you and Commissioner McAllister, as we go forward in this process.

CHAIRMAN WEISENMILLER: Okay. And my recollection is that Sempra doesn't use this model? I'm trying to recall if they use a similar model or --

MR. BRATHWAITE: I'm sorry? Oh, they use -- Katie Elder just told me that Sempra is using GCPM, Gas Competition Pricing Model, or something like that. So,

no, at one time many many moons ago, they used to, but I guess they don't anymore.

CHAIRMAN WEISENMILLER: Okay.

COMMISSIONER MCALLISTER: Do you typically get together with them, with other users of this model and other models to sort of compare and contrast assumptions, and look at, you know, do runs and sort of see what they tell you about the world, about what your model is telling you, sort of how your model represents the world versus a different one, or another configuration of the same one?

MR. BRATHWAITE: Well, yes. In previous cycles we have done such a thing where we have -- well, we have worked closely with PG&E in some of our previous cycles. The last cycle, I do not believe -- I think we did have a little bit of reach-out to Southern California Edison, who uses this model also. But, yes, we have reached out in the past and in this cycle we certainly would like to be doing that again, and we'll certainly do so.

COMMISSIONER MCALLISTER: I would suggest that just as a matter of course, really, so to inform their comments and they can sort of, if anything, if any differences emerge, it would be good to have those sort of earlier, rather than later in the process.

MR. BRATHWAITE: Absolutely. Absolutely,

Commissioner.

COMMISSIONER MCALLISTER: I had a question -- did you have another?

CHAIRMAN WEISENMILLER: Oh, just a follow-up just on your point for a second. I was going to encourage Edison, PG&E, and Sempra to file comments on this presentation and, again, in terms of areas where they agree or disagree, or where we can strengthen it. Certainly if anyone wants to speak now, that's fine, but if -- I suspect people would prefer to have time to think about these results and then give comments, but that would be very helpful, I think, to get those in writing for the record.

MR. BRATHWAITE: One caution I would just like to put out there, Commissioner, I mean, any comment is welcome, but these are our preliminary cases, okay, that's the only question.

COMMISSIONER MCALLISTER: I can totally appreciate that. So on slide 25, you explained this a little bit, I just wanted to get a little bit better understanding of why the high price case is jumping up and down in the early years there. Is that sort of accommodating structural changes? Or what's driving that? Is it market? What is it?

MR. BRATHWAITE: Okay. Now, in the high price

case, it was the only case so far where we actually forced LNG exports -- not imports -- exports I'm talking about. We really pushed exports in the high price case. So what is happening there is that shale, in anticipation of these exports, I mean, in the world of the model I'm speaking now, in anticipation of these exports, we have a significant amount of shale development ongoing. So initially you see this sort of price depression occurring right in here because of all that supply that is potentially available. But as the exports actually begin to occur, and they do begin around 2015 or so, then that is an added demand upon the resources here in North America. So what happens, this pushes the prices higher, and then the cycle starts over -- higher prices, more shale comes on, it depresses the price, and then the export is ongoing, it pushes the prices back up as more and more is demanded for the export market.

COMMISSIONER MCALLISTER: So is there -- so basically is it a function of the model and the periodicity of the models you're forced to sort of have each iteration is producing sort of a different decision set early on and at some point it evens out? I'm just a little clear as to why it just stops at 2019 or --

MR. BRATHWAITE: Oh, why it stops. Yes. Well,

the model will iterate until, shall we say, the differences between each iteration is minimal, shall we say? There are parameters that we must set to do so. So, yes, it will go through for each period, it looks at what it must do in that period to try and satisfy the demand. Now, all of these things must eventually all come together simultaneously, but it does look short-term at what will happen in the next period, in order for it eventually to have an overall solution. So, yes, there's a set of decisions that it must make that I don't want to say is independent, it is not independent, but it's all part of the entire decision set that the model will make in terms of reaching an eventual solution.

COMMISSIONER MCALLISTER: Okay, I don't want to talk too much about the model because I really am interested in the underlying reality here.

MR. BRATHWAITE: Okay. But did that answer satisfy you, though?

COMMISSIONER MCALLISTER: Yeah, it did, it did. It kind of tells me that you really need to use this experience to make -- to evolve your scenarios such that you get sort of something that might actually happen, I mean, maybe something like that would happen in the real world --

MR. BRATHWAITE: Yes, right.

COMMISSIONER MCALLISTER: -- but that you're refining your forcing function for exports in this case, for example, it seems like it could yield a better outcome in the future here.

MR. BRATHWAITE: Well, I mean, this is one of the problems; whenever we force, shall we say, noneconomic things, like the LNG that we forced in that example, it was not economic in the sense that it was not occurring because it responded to prices. We were actually forcing it to flow. So whenever you put noneconomic things into the model, a noneconomic flow, shall we say, into the model, it does produce some of these seesaw effects that we are seeing here.

COMMISSIONER MCALLISTER: Okay, thanks.

MR. BRATHWAITE: Sure.

CHAIRMAN WEISENMILLER: While we have the price thing up, do we have a sense of what the future strip looks like? It obviously varies from day to day, but how do these numbers compare to the current futures?

MR. BRATHWAITE: Well, we did do, shall we say a back of the envelope comparison between the future years. And if you look at the future strip, it falls within our zone of uncertainty at this point in time, but, you know, as we go forward that may change. But at

this point in time, it falls into the zone of uncertainty. But, I mean, like I said, we will be looking at these cases and refining them as best we can.

COMMISSIONER MCALLISTER: Okay, thank you.

MR. BRATHWAITE: Thank you very much. Anything else?

MS. KOROSEC: Let's open it up for any questions from the audience in the room first.

MR. TUTT: Good morning. Tim Tutt from SMUD. Leon, I was just curious about the rationale for assuming that RPS mandates in other states would be delayed in certain scenarios. Thank you.

MR. BRATHWAITE: This, Tim, is a bit of a controversial issue within our office; however, we think some of the budgetary issues that are ongoing in many of the states may force the delay of the RPS Standards. So we did make that assumption in some of the cases. But as I said before, we did not assume that in California in any way, shape or form.

MR. MANUEL: Leon Manuel of Southern California Edison. I guess I just have a curiosity and I guess it's something I can follow-up with you later. On the reference case, you had your percentage of power generation --

MR. BRATHWAITE: Yes.

MR. MANUEL: -- and as you ran through your high case and low case, did you see much variance in the amount of power generation from natural gas over time?

MR. BRATHWAITE: Oh, you mean in terms of the output?

MR. MANUEL: From the output.

MR. BRATHWAITE: Yes, there is. There is some variance, and we will be -- let me just say this -- we will be posting a full suite of the results of these cases and all future cases. Now, I don't know the exact timing of when those things will be posted. Ivin, do you have a good answer for that, when we will be able to post? But we will be posting a full suite of results of these cases, and you will be able to see the difference between the cases on the power generation side, yes.

MR. MANUEL: Okay. And did that include just on the national figures? Or did it also include the California component?

MR. BRATHWAITE: Both.

MR. MANUEL: Both?

MR. BRATHWAITE: Yes.

MR. MANUEL: Thank you.

MS. KOROSEC: Anything else in the room before we open it up to our folks online? All right, we do have one question from a caller. If you would go ahead

and open the lines, I'll let you know when the lines are open. And the question is from Richard Stevie. Richard, I believe your line is open.

MR. STEVIE: All right, thank you. Can you hear me?

MS. KOROSEC: Yes, we can. Go ahead.

MR. STEVIE: Okay, thanks. Actually, I had two questions, one kind of a follow-up on the volatility in the high price forecast. It's just the thing that strikes me about this is you really are talking about boom bust cycles in the prices, and even within the reference case, I would think you would tend to see, as well as in the low case, you would tend to see the boom bust cycles having an effect on that price forecast which could have a tendency to blow apart maybe a little bit more the range of these forecasts. Have you thought about applying that to the other scenarios?

MR. BRATHWAITE: Well, I think we are conflating one or two things here, sir. What is causing that seesaw, in effect, is that we have forced in the high price case -- and this was the only case in which we did this -- we forced LNG flows to be exported. Whenever in a model, now maybe it may be an issue within the model itself, but whenever we force non-economic flows, it does produce this also seesaw, in effect. I don't think

it would open up the range of uncertainty if we did that in the other cases. But what we are trying to do, we were trying to capture a particular effect. In the high price, we were trying to get high prices; in the lower price, we were trying to get low prices. So we only want to do things that are plausible in that regard, in each of those individual cases. I hope I'm answering your question.

MR. STEVIE: Well, you are, it's just that what I've seen in terms of modeling gas price projections is that, even in a reference case, that will generate both high and low prices because of boom bust cycle of supply relative to the prices. It's just, you know, if you look at the history of natural gas prices, they're not a smooth line --

MR. BRATHWAITE: True. That's true, yes.

MR. STEVIE: -- and a lot of that can be due with the boom bust cycle that goes on. But I understand that you're trying to do. Let me ask my other question, is early on you were talking about -- I think you were talking about nodal constraints on the availability of resources.

MR. BRATHWAITE: Yes.

MR. STEVIE: Or prices at the nodes. Have you thought about a need to have maybe smaller area

forecasts of gas demand, as well as other energy consuming sectors as a way to improve the price projections at the nodes?

MR. BRATHWAITE: Could you expand on what you mean by smaller area? I'm not sure I understand exactly what you mean by that, sir.

MR. STEVIE: Well, I'm assuming here that you're looking at kind of a broad area, maybe even the whole state, for the price of natural gas.

MR. BRATHWAITE: Yes.

MR. STEVIE: Okay. And maybe I misunderstood what you were doing here, but it sounded like you were talking about the different nodes, the prices could be different?

MR. BRATHWAITE: Yes, they are different, yes. They are different nodes. But let me -- could I explain something?

MR. STEVIE: -- and that's what I was talking about because it would be the demand in an area versus the supply.

MR. BRATHWAITE: Oh, I see. Okay. Let me -- maybe if I back up a little bit and try to explain how the model is structured, and maybe it will get to your question. In the model, in North America we have something like 90 regions. In California alone, I

believe we have five or six regions, I'm not sure of that number, but it's somewhere around there. Each one of those regions have five demand sectors that are disaggregating within our model. We have residential, commercial, power generation, industrial, and transportation. So in terms of smaller area demand, I think we are doing some of that, maybe not to the extent that you indicated in your question, but certainly we are at a level of disaggregation that try to capture as small an area as possible within each of the regions. And remember, California alone has about five or six regions. Now, does that get to the heart of your question? Or is it something else that you're asking me?

MR. STEVIE: No, actually that helps. Thank you.

MR. BRATHWAITE: Sure. You're welcome, sir.

MS. KOROSEC: We have a couple more questions that just popped up after that discussion. The first one is Xiabo Wang from CAISO. We're opening your line now in case you're talking and we're not responding to you. Oh, I'm sorry, apparently that one is not on the phone, they're just sending us a question. So we'll pull that up in a moment.

MR. WANG: Hi.

MS. KOROSEC: Okay, we can hear you now. Go ahead.

MR. WANG: Hi, Leon. On this slide on page 25, you're showing the projected Henry Hub price --

MR. BRATHWAITE: Yes.

MR. WANG: -- into the future. We are aware that, at the Federal Government, at EIA, Annual Energy Outlook, they also forecasted the future Henry Hub prices. So how do we compare this Henry Hub price with that Henry Hub price, in general? So is it kind of similar? Or is it having different trends?

MR. BRATHWAITE: I would not say the trend is different, I mean, it's as different in terms of its magnitude, there's no doubt about that; but in terms of the overall trend, EIA's forecast is looking quite similar to the one that you have before you right now. But there are differences and obviously that comes from the input assumptions, which is they are using a different model than we are. But in terms of the trend, it is similar.

MR. WANG: I see. The reason I'm asking this question, for your information, is because we have been using the EIA forecasted Henry Hub price to build the ISO Production Simulation Model to run the electrical consumption, which is more or less similar to Angela

Tanghetti's -- their group of work. But of course, our focus is on the power system, on the renewable integration, and transmission congestion analysis. Okay, you clarified the question. Thanks.

MR. BRATHWAITE: You're welcome, sir.

MS. KOROSEC: We have one last question from a name that's familiar to our staff here, it's from Jairam Gopal.

MR. ANGHA: Actually, this is Amir Angha from SCE, Southern California Edison. Jairam is in the room, though. Thank you for the presentation. I have a couple of questions. First of all, I wanted to confirm that we also use the Market Builder in-house, and in the future we would like to collaborate with you and your staff in terms of sharing the information, or assumptions that we have, and to the extent that you can also share some of the detailed assumptions with us so that we can comment on that, it would be great. I have a couple of questions. Would you please elaborate more on the small "m" model that you mentioned in your presentation? Is it more a statistical model to come up with the initial type and quantities, or something else?

MR. BRATHWAITE: Well, it is an econometric tool that we use here at the Commission. It's Excel-based. What it does is that within the model we have summary

regression functions set up, a bunch of regression equations that we are trying to determine first the elasticities and also the initial starting values, as you are aware of. So that small "m" model, is what I'm referring to as the Excel-based model that does our regression and produces the initial starting values for the general econometric model, the NAMGas Model.

MR. ANGHA: Okay, and how far did you go in terms of the historical data? And my follow-up question is how do we correct for basically the structural shifts in the market due to shale or other things that we have seen over the past couple of years?

MR. BRATHWAITE: Okay, your first question was -- what was your first question, I'm sorry? Tell me the first part of the question.

MR. ANGHA: The first one was how far of the historical data do you use in that model. And the second question is how do we correct, or like adjust for the structural shifts in the gas market due to shale.

MR. BRATHWAITE: Okay, in terms of how far back, we go back to 1986 in terms of the historical data. Peter, that's correct, right? Yes, 1986. And it was just confirmed by our Demand expert here, Peter Puglia. Now, on the other side, in terms of your other question, in terms of adjusting for the shifts in the gas market,

we do not, shall we say, physically adjust for any shift in the market. What we *do* do is we represent the shales in the individual supply cost curves, we input them at hopefully an appropriate cost, and allow the market -- the world of the model -- to decide which one would reproduce and which one will not be. So we do not do any sort of physical alignment or realignment, but we allow the market as it exists inside the model to make that determination for us.

MR. ANGHA: Uh-huh. So in other words, I also hear that you use like 70 years, '75, '86, and 2003, as the reference cases, correct?

MR. BRATHWAITE: As a representative cost environment, yes.

MR. ANGHA: Okay, but those years are all like before this shale revolution, so I just wanted to see what would be the impact of using those years as the reference years in the model, rather than like a more recent year to adjust for the new environment, the new market structure?

MR. BRATHWAITE: Oh, I see your point, and that's a very good point in terms of the revolution in shale. As we go through this process, this much I can promise, yes, we will be looking at that very issue. Shale, you're right, shale is a game changer, it will

really change things in the marketplace, there's no doubt about that, and we will be looking at that variously in terms of what have happened to the cost environment, is the new normal different from the old normal, that is the question I think you are asking. So we will try to make some -- we will try to discern whether that is the case or not.

MR. ANGHA: Okay, thank you.

MR. BRATHWAITE: And that was a very good point. I must compliment you on that.

MR. ANGHA: Thank you. And one last question. Recently El Paso announced some exports to Mexico, some new project --

MR. BRATHWAITE: Yes.

MR. ANGHA: Are you counting those in the model in the reference case? And you know, any indication of the impact on the Topock prices?

MR. BRATHWAITE: On this reference case, no, we are not counting that, but this is something certainly we would be looking at as we go to the next. Remember, these are just preliminary and we're going to be doing another round of runs here in the next -- certainly within the next month. But if we have some good intell on that and we know -- we are aware of the announcement, if we have some good intell on it, sure, we certainly

will include it in the model.

MR. ANGHA: Okay, thank you very much. And Jairam in the room has another question if you don't mind.

MR. GOPAL: Leon, I was looking at the reverse that you showed --

MR. BRATHWAITE: Yes.

MR. GOPAL: -- the number that you show for gas exports, does that include LNG exports from these liquefaction terminals?

MR. BRATHWAITE: Yes.

MR. GOPAL: So then the follow-up question would be, you talk about saying that the exports were allowed only in the high case, so how come we see so much the exports in the other two cases?

MR. BRATHWAITE: Well, those are -- oh, no, let me back up here for a second. Those are pipeline exports, mostly.

MR. GOPAL: They are pipeline exports, too?

MR. BRATHWAITE: Yes. Those -- that number represents both pipeline exports and LNG exports.

MR. GOPAL: Okay, and pipeline exports would be to Canada and Mexico? Or just Mexico?

MR. BRATHWAITE: Canada and Mexico, which probably corrects something I said previously; there is

some exports going into Mexico from the lower 48, but the new stuff that was recently announced by El Paso, that is not included at this point in time.

MR. GOPAL: Okay. And a clarification question. The elasticity range that you provided, is that the price elasticity?

MR. BRATHWAITE: Yes, it is. Yes.

MR. GOPAL: Okay.

MR. ANGHA: Thank you very much.

MR. BRATHWAITE: You're welcome. Thank you very much for the questions.

MS. KOROSEC: All right, we have time for one final question, this is from Mia Vu from PG&E. Mia, I believe your line is open.

MS. VU: Can you hear me?

MS. KOROSEC: Yes, you need to step away from your computer microphone, though. We're getting feedback here from the time delay between us and you.

MS. VU: So what should I do?

MS. KOROSEC: Yeah, that sounds good. Go ahead now.

MS. VU: I need some clarification. You have reference case and high consumption case and low consumption case, but in the page 25, you also have a high price case as well as low price case. Are the high

price case some problems in high consumption case?

MR. BRATHWAITE: Yes. I apologize if my slides were a little bit unclear in that regard. The high price case is all low consumption case, and the low price case is a high consumption case. Obviously, we are not seeing as much variation as we would like to, and this is something that we'll be working on as we go through this process; but just to clarify, our low consumption case is a high price case, and our high consumption case is a low price case. And the mid-case, of course, is the reference case.

MS. VU: Okay, that helps. Thank you.

MR. BRATHWAITE: You're welcome.

MS. KOROSEC: All right. That is it for our questions for this portion of the agenda. I think now is time for us to break for our lunch.

CHAIRMAN WEISENMILLER: Right. Any public comment?

MS. KOROSEC: That was --

CHAIRMAN WEISENMILLER: Just in terms of general public comment, let's see if --

MS. KOROSEC: Oh, okay. Anyone here wants to make a comment here before we break for lunch? All right, great, so we will reconvene at 1:00. Thank you.

(Off the record at 11:59 a.m.)

(Back on the record at 1:13 p.m.)

COMMISSIONER MCALLISTER: Let's start off this afternoon's session. We were talking about electricity forecasts.

MS. KOROSEC: All right, we're going to start with Chris Kavalec --

COMMISSIONER MCALLISTER: Actually, let me just say we'll wait for Commissioners Florio -- well, we'll get going now and Commissioners Florio and Chair Weisenmiller will be with us when they can.

MS. KOROSEC: Right.

COMMISSIONER MCALLISTER: So we'll start off.

MR. KAVALEC: Good afternoon. I'm Chris Kavalec from the Demand Analysis Office here at the Commission. And I'm going to talk about a general approach and assumptions for electricity and natural gas Demand Forecast, what we refer to as the 2013 IEPR Demand Forecast.

More specifically, I'll be giving a brief overview of our forecasting timeline, talking a little bit about our modeling approach, and then the main topics, Economic and Demographic Assumptions and Other Assumptions, which means efficiency and self-generation.

So we do this forecast every two years and annually we provide an update for resource adequacy

proceedings for CAISO and the CPUC, and that's a short-term peak forecast.

As Suzanne mentioned earlier, the first step in this process is our request to the utilities for the demand forms and instructions whereby they provide us historical data on sales and rates and so on, and most importantly their most recent forecast so that we can compare it to our forecast.

Here we are at our workshop on Forecast Assumptions; we will develop a preliminary forecast which we will release in May; and we will have a workshop towards the end of the month. Before that workshop, we will also talk to our stakeholders and the larger utilities and talk about any big differences in our forecasts and attempt to resolve those differences before we get to the workshop, itself.

And after the preliminary workshop, based on input and comments, we will make adjustments to the forecast as needed and we will also update our economic and demographic projections and release a revised forecast in August. And if everything goes well, that Demand Forecast will be adopted in the fall.

Okay, when we forecast, we forecast for individual sectors listed here: residential, commercial, and industrial end use methodologies. The

residential and commercial models date back to the late '70s and have been updated over the years with Residential and Commercial Saturation Surveys. More about the industrial model in a minute.

In the last forecast, we also estimated econometric models for the three big sectors, residential, commercial, industrial, as sort of a cross check, and to supplement our end use methodologies. For example, we replaced the price elasticity in the Residential End Use Model with one we estimated in the Residential Econometric Model. We also used the Econometric models to estimate impacts from climate change.

There are summary and peak models on the next slide, but let me just mention that in the future we're looking at revising our models and using what's referred to as a hybrid methodology, meaning a combination of econometric and end use elements. Basically what we're trying to do is combine the best of both worlds in these methodologies, so we'll have the detailed end use model combined with the behavioral characteristics that you can estimate through an econometric model.

Here's what our structure looks like. The residential and commercial models are actually made up of two sub-models, a model in the residential case for

projecting the number of households by type, and the actual energy model and commercial has a floor space component to project floor space and an energy model. For agriculture, we forecast for three different segments; in industrial, we divided up into thermal processes, production processes, and other end uses.

Results from the sector model are provided to our summary model, where results are aggregated, weather adjusted, and calibrated. And also, the summary model provides end use results to our peak model, where hourly load shapes are applied just to produce an annual peak projection.

As we go from forecast to forecast, we attempt to improve our methodologies and here's a list of what we're currently working on. Our Industrial Econometric End Use Model dates back to before deregulation, and we never got the computer code for that model. The idea was that there would be a users group to support the model and any changes you want to make to the model. Unfortunately with deregulation, that all fell apart, and so we were left with this industrial model without the computer code, and we've made some improvements over the years, but there's only so much we can do without the code itself.

So what we're doing is revamping this model,

rebuilding it from the ground up, although we use the same basic methodology, meaning it's forecasting at the subsector level -- subsector, for example, is paper or textiles is another one -- and the forecast is based on projected output for those subsectors, industrial rates, and then energy characteristics. For example, motor efficiencies is a critical variable in the industrial model.

We're introducing a Self-Generation Model for the commercial sector. By self-generation, I mean distributed generation that's used on-site. In the last forecast, we introduced a residential model which seemed to get pretty reasonable results, and in this forecast we'll attempt to supplement that with a commercial model.

In the last forecast, we incorporated climate change into our peak demand by estimating potential increases in average temperatures because of climate change, and in this forecast, we're going to incorporate climate change also into our energy forecast through degree days, cooling degree days and heating degree days, and also extreme weather. When we do a peak forecast, we do a 1 in 2 peak forecast, which means a forecast assuming "average weather in a given year," and we do a 1 in 10 forecast, which is for more extreme

weather; in other words, when you're up at the 90th percentile in terms of temperatures historically. The one in ten peak forecast is important for resource adequacy purposes, so the question here is whether climate change would affect the relationship between one and two and one and ten. In other words, if we have more extreme temperatures, will the one and ten peak increase relative to the one and two.

So we have Scripps Institute working on that for us and, if all goes well, the results of their analysis will be available to us so that we can incorporate that into a revised forecast.

We are estimating econometric models for natural gas to go with our Electricity Econometric Models that we've already estimated, and we're presenting results at the climate zone level. We forecast for eight different planning areas, Burbank, Glendale, Imperial, LADWP, Pasadena, PG&E, Edison, San Diego, and SMUD. And within those planning areas, some of those planning areas are multiple climate zones. For example, PG&E has five, Edison has four, and historically we used climate zones in order to get a better estimate of weather sensitive electricity and natural gas use because we know that weather sensitive use is very different comparing the coast to inland areas, or the north versus the south.

So this time we're going to provide not only weather sensitive usage at the climate zone level, but also the rest of the non-weather sensitive usage.

So this is the first step in our effort to provide a more disaggregate forecast, and this is a discussion that we're going to be having in the next few months, or a year or so, because there are a lot of issues to consider when disaggregating in a forecast beyond the climate zone or the county level, not the least of which is data. If we're going to provide a more disaggregate forecast, we're going to need to get more disaggregate billing data from the utilities. So that would involve some negotiations and probably some lawyers getting involved, and so on.

Also, our large-scale saturation surveys will have to become larger scale in order to cover a more disaggregate geography. And if we start talking about going down to a Zip Code level, or a Census Track level, or Busbar level, then you have to start thinking about things like zoning laws, where the new housing developments are going to be, whether a large industrial customer is going to leave in the next few years, or whether a large customer is going to come in, and so on.

And finally, we have to think about resources and it will take more people and probably more

consultant dollars to put together a forecast the more disaggregate that you go.

Okay, when we forecast, we attempt to provide a range through three scenarios, a high, a mid, and a low. And the main factor driving the differences among these scenarios is economic and demographic growth, higher in the high case, lower in the low case. But we also make other assumptions to increase the demand in the high case and lower it in the low case. We assume lower rates in the high growth case, lower efficiency program impacts, lower self-generation impacts, and stronger climate change impacts, and the reverse in the low case.

Now, one could make the case that these scenarios may not always be 100 percent consistent; for example, if you have high economic and demographic growth, well, you're putting upward pressure on demand, and therefore upward pressure on rates, so maybe it makes more sense to have high economic growth with higher rates rather than lower rates. However, we are attempting to provide a scenario that makes the assumption that these factors come together to provide the highest possible, or lowest possible scenario. And a scenario like I just mentioned, high economic growth and higher rates, would fall within this range. So it would be covered by this range. But if you feel

strongly about the consistency issue here, we want to hear from you and your comments.

Here are the important economic and demographic variables that we use: personal income and number of households for the residential sector, along with persons per household; and then in the residential econometric model, we use the unemployment rate; commercial end use model is a function of floor space, which is estimated by various economic and demographic variables; and the industrial model, as I mentioned before, we forecast down at the subsector or NAICS grouping level using projected employment, or projected output in that subsector; population is of course important because it drives number of households in the residential model, it also is important for floor space. And I'm in the midst of attempting to incorporate financial variables into our econometric models because we know that variables like foreclosures and bankruptcies were important in the last few years in terms of energy use. So if variables like that yield significant coefficients, they'll be part of the econometric models.

Okay, economic scenarios available, we have many. Moody's provides seven scenarios, a base case and six alternative scenarios listed here. Global Insight

provides three, a base, a high, and a low. Our new kid on the block, or at least new kid in California, is Oxford Economics, which we're trying out for this forecast. And we also look at UCLA's base case. UCLA doesn't provide all the variables that we need for the forecast and they don't forecast our far enough, so we're not actually using UCLA in the forecast, but it's provided here as a reference.

So for employment, here is what all the scenarios look like -- and this is a perfect example of too much information on one graph. But if you look towards the right-hand side, in 2024, you'll see the range that we end up with there at the end of the forecast period, and that range is bracketed by Global Insight low case on the low end, and Global Insight high on the high end. A similar situation for GSP, Global Insight on bracketing the range, and then the Moody's base case right in the middle there.

So from these, we want to choose three scenarios to use for our forecasts, so a possible candidate for the low case would be the Global Insight low case, the lowest one in there, the dotted line shown there. However, if we look at manufacturing output, we see that Moody's forecasts, or Global Insight's forecasts, the three dotted lines there, are much higher than the other

forecasts. So we've talked to Global Insight about this and it basically comes down to they're just a lot more bullish on manufacturing in California than the other forecasters, especially in electronics and computers and high tech, that's what's driving this rapidly growing forecast.

But anyway, my point is that it doesn't make sense to me to use the Global Insight low as a low case when in manufacturing it's so much higher than the other cases.

Going back, my proposal is then in the longer term to use the next lowest case, which is Moody's S5, lower long-term growth, that's the orange line there, the second lowest towards the right-hand side of the graph. In the shorter run, though, we know that there's also still uncertainty and it's still possible we could go into another recession, not as likely as, say, a couple years ago, but it's still a possibility, although it probably wouldn't be nearly as bad as the one we had in 2008. So I'm also proposing to combine this lower long-term growth case with one of these cases that shows a slump in the short-run.

So let me be more specific here. Here's our proposed scenarios for economic growth. In the high case, the Global Insight high which was the highest as

we saw, the mid-economic growth case would be the Moody's base case, which was right in the middle of all those scenarios, and then in the low growth case, I propose combining Moody's S3, a second recession, although mild compared to the one in 2008, and in the short-run combined with Moody's S5, lower long-term growth in the long-run.

And here are some factoids about these scenarios. In the high case, the assumption is that the European debt crisis goes away, unemployment drops to below seven percent by the middle of this year, and the recovery in housing is very strong. In the mid-case, on the other hand, unemployment continues to drop, but not by as much as in the high case, and there's a housing recovery, but not nearly as strong as in the high growth case.

And in the low economic growth case, in the short-run, second recession, unemployment goes back up to 11 percent temporarily, the housing market gets worse, foreclosures go up, and then in the longer term we have a contractionary fiscal policy and the European debt crisis continues. So we want to hear from you, what you think of those scenarios, should we be considering other ones? Do these seem reasonable?

And here's what they look like for employment.

In the low case there in the green, you'll see that pink in the middle, that's where the S3 case, the mild recession combines or intersects with the lower long-term growth case. So basically this scenario is the S3 until 2018, and then it becomes the S5 lower long-term growth.

Here's what it looks like for GSP and here's what it looks like for manufacturing output.

We also want to do scenarios for population and I show four here, starting at the top with Moody's, and then Global Insight below it. Unlike the economic scenarios, Moody's and Global Insight only provide one population scenario. And you'll notice DOF there in the green, this is the forecast they recently released, it's lower than the others and this is a pretty low forecast, it's less than one percent population growth for the next 10 years, which is the lowest that I remember them ever putting out.

And I recently checked the forecast by the Public Policy Institute of California which uses the USC Demographic Unit, and their population forecast was in between the Global Insight in red and the DOF in green. So we typically consider the DOF forecast the "official" population forecast for California, but it's lower than all the other ones. So if these were the only scenarios

available, I would propose to use the DOF base case for the low demand scenario, the Global Insight case for the mid, and the Moody's case for the high; however, DOF is also providing us two alternative scenarios at the end of this month, so I wanted to look at those first before I make a specific proposal for population. So I apologize that's not available yet and we do want to hear from you, any thoughts you have on the population forecasts.

Okay, turning to efficiency, we historically make the distinction between committed efficiency or efficiency from initiatives that have been approved, finalized, and funded and/or already implemented, and uncommitted efficiency, meaning savings from initiatives that have not been funded or approved yet. There are many that don't like the word "uncommitted" because it has a negative connotation, it doesn't sound as likely if you start a word with "un." So I'll float out the alternative possibility of "achievable" here for "uncommitted" and see if that sticks.

So as we go from forecast to forecast, some initiatives that were previously -- they were considered previously as achievable become committed. An example of that is the latest Title 24 Appliance Standards that have been approved, were not part of our baseline

forecast in 2011, but now, since they have been approved, they're final, they will be part of the 2013 IEPR forecast.

Another example is the 2013-2014 IOU Programs which were considered achievable in the last forecast, but now have been approved by the CPUC, so they'll be part of our baseline forecast. And in addition, 2012 POU Programs.

Now, within these scenarios, the way it works for Standards is that the higher the demand, since you have more houses being built, more commercial floor space being built, the standard savings are going to increase, so they'll be higher in the high demand case, and lower in the low demand case.

COMMISSIONER MCALLISTER: Chris, can I just jump in real quick and comment on the efficiency? I think the IEPR is a perfect forum to be having this discussion, I wish Commissioner Florio were here with us right now, but I wanted to just highlight that there's a really robust discussion going on about this right now between the three agencies, essentially -- and you're aware of that -- and I think the role, kind of a question, is what are likely outcomes from efficiency and how -- and which should or might not be included into the case forecast?

And so it's really the PUC has a great interest in this because, you know, they run the investor-owned utility energy efficiency programs. But the ISO does also because they need to make a judgment about what forecasts they're going to really operate from, and so I think this is a real critical discussion not just from the perspective of energy efficiency, there are other aspects of the electricity demand scenarios that impact the base forecast, as well, they all sum up to the base forecast. But I think this is a particularly topical one, one I'm really looking forward to fleshing out in our IEPR workshops going forward, so just to highlight that.

MR. KAVALEC: Yeah, and I have another slide on that topic coming up, so we can get into it more if you want.

COMMISSIONER MCALLISTER: Great.

MR. KAVALEC: So for the IOU efficiency programs for 2013-2014, my proposal is to have low program savings, lower program savings in the high demand case, and higher program savings in the low demand case. In the mid case, we'll be using utility forecast net savings recently filed with the CPUC. In past forecasts, we have taken these utility forecast net savings and made downward adjustments to them by some

estimated realizations rate because history has showed us that we've had instances where utility forecast net savings ended up being higher than what was actually realized. However, as I understand it, for the 2013-2014 forecast net savings, these have already been adjusted to be consistent with the 2006, 2008 CPUC EMV results, so that they are fully adjusted through the DEER (Database for Energy Efficient Resources) process. So we feel comfortable using these forecast net savings as is because that adjustment has already been made.

In terms of a low and a high, I propose 10 percent lower and 10 percent higher. And that 10 percent is a semi-scientific number that comes from scenarios that we did earlier this year with Navigant when we were estimating the incremental uncommitted savings for the CPUC, for the LTTP process. And we ran these scenarios and found that there was a maximum of 10 percent higher and 10 percent lower for programs, depending on how we changed the inputs. So that's how I came up with this 10 percent number.

Okay, uncommitted or "achievable" efficiency. This is going to be based on the CPUC Goals Study, so since that hasn't been completed yet, this won't be part of our preliminary forecast, but it will be part of the revised version. Our plans are to begin work in May

when the Goals Study is complete, with Navigant and CPUC staff to begin to develop reasonable incremental achievable savings. Oh, I should say here that the key, what we're measuring here, is incremental achievable efficiency; that is, achievable efficiency that doesn't overlap with committed efficiency that's already in the baseline forecast.

So we will begin to develop these incremental achievable efficiency scenarios, and we will also have CAISO involved, they have agreed to take part in this process, and the goal is to develop one or more incremental achievable efficiency scenarios that we're all comfortable with, and that not only can the CPUC use for their LTTP process, but also CAISO can use for their analysis, for example, transmission planning.

And the Commissioners can -- correct me if I'm wrong -- but I think the plan is that this incremental achievable scenario, or scenarios, would be adopted along with the baseline forecast.

COMMISSIONER MCALLISTER: I think the adoption -- yeah, so they would all be adopted together, that would be the plan, and the question is whether sort of there's -- how it's presented, sort of, you know, what is the final sort of base -- what we're all considering the base forecast, and what does it include, what does

it not include.

MR. KAVALEC: So when we refer to a baseline forecast, that means -- or it has meant -- a forecast that only includes committed efficiency savings. So the question is, when we adopt these incremental achievable, will they become a part of the baseline forecasts, or will they remain separate from the baseline forecast, I guess, is the question.

COMMISSIONER MCALLISTER: Right. I think that's still an open question.

MR. KAVALEC: Okay, finally, self-generation. As I mentioned, we're putting together a predictive model for the commercial sector to go along with our model for the residential sector that we used last time. And these are models that are based on payback, which in turn are based on initial costs, incentives like tax credits, and avoided rates. And within our scenarios, we have two opposing effects. In a low demand case with higher rates, you have more adoption because of the higher rates, and then in the higher economic growth case, or demographic growth case, you have higher population growth, therefore more households, more commercial establishments, and therefore higher demand, all else equal, for self-generation, or distributed generation technologies.

At least in the last forecast, it netted out that the first effect was stronger than the second, so the higher rates had more impact than higher population growth, which means that in the low demand scenario you'll have more self-generation than in the high demand scenario.

It's also possible that we could develop another scenario, for example, we could assume that CSI incentives and/or the Federal Tax Credits will be reinstated in 2016, but I haven't heard anything definite moving in that direction, maybe someone has more intelligence than I do. And also, I don't mention it here, but in our Demand Forecasts, we include non-event-based demand response, so that's demand response from programs like permanent load shifting, critical peak pricing. It doesn't amount to much right now, it's less than 100 MW for the entire state, but it will become more important as the years go by. And I say "non-event-based" and that's to distinguish from event-based demand response, which is considered on the resource side, or on the supply side, as it's not part of the Demand Forecast.

So with that, I'll ask the Commissioners for questions or comments.

CHAIRMAN WEISENMILLER: Yeah, I had one question

on the Building Standards part, and that is it would seem like, with higher demographics, they'll be more building starts and we may well find higher energy efficiency savings from the Building Standards than with, yeah --

MR. KAVALEC: Yeah, so I made the distinction between what's going to happen with the standards, which will increase with demand in our efficiency program scenarios, where we assume low savings in the high demand case, and vice versa in the low case. But, yeah, you're right.

CHAIRMAN WEISENMILLER: Right.

COMMISSIONER MCALLISTER: I'll just ask a couple questions here. So let's see, on slide 7 you had talked about, oh, let me see, that's the problem with waiting until the end for questions. But you had talked about the disaggregation and I'm very excited about that, to get a more granular view of the forecasts, certainly moving in the climate zone, down to the climate zone level is a big step in the right direction. I'm wondering -- and then you also said the regional approach is essentially by utility service territory, or by --

MR. KAVALEC: Yeah, we call them planning areas.

COMMISSIONER MCALLISTER: By planning areas,

exactly. So you could actually have outputs from this that are by climate zone and by planning area, right?

MR. KAVALEC: Yeah, that's what we're planning to present for this forecast.

COMMISSIONER MCALLISTER: Yeah, so I think that's a big step in the right direction and it actually begs the question for me, are you -- and given the land use questions and sort of the next couple steps you'd have to take down the road to really get a granular forecast, I'm wondering how -- whether and how you're developing relationships with the MPOs and the COGs who actually do land use planning, and transportation planning, and are really on the ground sort of figuring out what those localities are going to look like in the future.

MR. KAVALEC: Yeah. So the way I envision it, if we go this route, we would have to have economic and demographic projections down at, say, the Census Tract level. And those would have to be informed by whatever information we have for land usage and zoning and so on at the local level, so we would definitely have to work with the local communities when we put this together.

COMMISSIONER MCALLISTER: What's your sort of stepwise timeframe for making that happen? Sort of see how it goes this time? And then in the next update,

take the next couple steps?

MR. KAVALEC: Yeah. I think, as I mentioned, we want to have this conversation in the next few months and decide on a strategy and a plan, and begin to put that strategy in place by the next forecast. And you're right, it probably won't be complete by the next forecast, but we'll take the next major step for the 2015 IEPR Forecast.

COMMISSIONER MCALLISTER: I think that would be very exciting and I think you'd find a lot of enthusiasm. And one big question, as I think you said, was the resources and sort of what that looks like in practice --

MR. KAVALEC: That's right.

COMMISSIONER MCALLISTER: -- because that does become a much bigger lift. So that's the only question I had for now.

COMMISSIONER FLORIO: Just on this question of the incremental achievable energy efficiency, you know, you're waiting for further information on that, is that ultimately a policy decision at the end of the process, whether to include it in the baseline, or have it alongside the baseline?

CHAIRMAN WEISENMILLER: Typically we've adopted it separately and I think, you know, the issue in part I

think the PUC is concerned on is that we typically do low/high/medium, you know, expected. And so presumably you want to be using something like "the expected case." And I think the concern is, if you're using expected, and say the ISO is using the low, then you have these sort of mismatches.

COMMISSIONER FLORIO: Yeah.

CHAIRMAN WEISENMILLER: But our hope is at this point, when we get everyone agreed that the expected case is the expected case --

COMMISSIONER FLORIO: Yeah.

CHAIRMAN WEISENMILLER: -- and at some point it becomes just arithmetic, you know, you then adopt it in that, but, again, it's just how do you get to the stage where we're all agreeing upon what's expected. And that's why it's important that you're here today and certainly it's important the ISO is here listening, so that again we can get a consensus on what's reasonably expected.

COMMISSIONER FLORIO: That's the challenge, yeah.

COMMISSIONER MCALLISTER: I would add to that that, you know, partly the near term is "committed," that's obvious, it's going to happen, it's funded and everything, and so I think the question is how we then

approach the out years, and particularly the further out years, and sort of how we can quantify both the expected and what the uncertainty around that expected is, and incorporate that into the forecast. And I think the ISO has a view of how they would expect to -- how they look at that issue, and obviously none of us want to undercut the importance of energy efficiency, and not create a self-fulfilling prophecy where it's undervalued. And so I think that's the concern, to make sure that it's right, that it doesn't undercut the future value of energy efficiency so that we don't over-procure, but at the same time, you know, is low enough risk.

CHAIRMAN WEISENMILLER: And it's good to talk a little bit about the disaggregation because obviously at some point if we disaggregated down to, say, the Busbar, you know, we'd be basically then having to forecast, say, for Hewlett Packard what is their growth going to be at that particular Busbar, and the econ demo. So, you know, as I say, we're going step by step. I know the things you would like to get to are very disaggregated, but we're certainly going to run into limits as we step forward on just how far down we can go. But presumably we can do better than service territory-wide, or climate zone-wide, to at least another couple levels down before we just, again, run

into the privacy questions. So, again, we need the econ demo forecast, so can you recall do that at a Busbar level?

COMMISSIONER MCALLISTER: Well, at some point you've got to draw the line when you start having to do distribution grid planning as part of your forecast, so we don't want to necessarily go there; but to the substation level, perhaps, or something like that. I mean, that could be useful if we have the computing power and the resources to sort of put it together in a way that makes sense.

CHAIRMAN WEISENMILLER: It wouldn't be unusual for, say, Hewlett Packard to own its substation, so when you get to that point, you would be -- as opposed to I think there's a substation for the whole subdivision, or for that part of town.

COMMISSIONER FLORIO: And the ISO local capacity areas, of which there are like 11 or 13, would be another more aggregated, but at a level that could be used for grid planning. That might be a mid-point along the way.

MR. KAVALEC: And this is a discussion we want to continue with our Demand Analysis working group. We'd also like to hear from our academic expert panel, have them weigh in on this, too.

So if the Commissioners didn't have anything else, we can go to questions in the room.

COMMISSIONER MCALLISTER: Yeah, please, let's go to questions.

MR. MARTINEZ: Hello Commissioners, Chris Kavalec, thank you for the opportunity to speak. My name is Sierra Martinez and I'm representing NRDC. Thank you, Chris, for this updated efficiency forecast. I see a lot of progress being made, especially in this uncommitted realm.

I think with regards to the question of which case should be the expected case that this Commission adopts, the one that includes uncommitted efficiency, or the one that excludes uncommitted efficiency, I think it's critical that this Commission choose the expected case that includes the uncommitted energy efficiency. There will be reasonable debate about how much future energy efficiency will or won't materialize, but we need to move beyond the threshold question of whether it will materialize and move on to how much of it will materialize. We can all agree that that answer will not be zero. And for this Commission to adopt one that excludes uncommitted energy efficiency would mean that this Commission expects its own future Title 24 Standards to not accomplish energy efficiency savings,

which would contradict the Commission's own work, as well as the loading order.

So I urge this Commission to take this opportunity to work with the joint energy agencies; as we saw in the recent Senate Energy Committee Hearing, there's a real need to coordinate and better incorporate future energy efficiency in our Demand Forecast and how we rely on it in procuring supply-side resources. We'll have more comments in our written comment. Thank you very much.

MR. KAVALEC: That's "achievable," Sierra, not "uncommitted." Don't be so negative. [Laughing]

MR. MARTINEZ: Which is a second comment that I have -- we'll write more on it -- but I agree wholeheartedly that "uncommitted" is a term that is not flattering and we could move beyond something maybe like -- I just want to make sure there are nuances with the potential study that CPUC is undertaking in the universe of achievable savings, and to make sure we don't conflate the two. But I agree with the direction of a more positive label.

COMMISSIONER MCALLISTER: Thanks very much. I appreciate your comments. And these are key issues we're going to be talking about and I think -- and there's broad alignment between the two Commissions, I

think, on the fact that it's going to be non-zero, and certainly we don't want to just be inhibited by the model doesn't have inputs for that, so we can't do it, right? So that's not a productive approach. But a very legitimate point of discussion is what the uncertainty around future energy efficiency is, and how we reflect that properly in the forecast, and I think the discussion, at least the one that I want to have, is really aimed at understanding kind of the -- certainly make it not just a normative statement about what ought to happen, but actually try to reflect what we think will happen -- with everybody in the room, right? Because the forecast isn't about what -- it's not about what telling the world what -- you know, it's not an advocacy exercise, right? So we certainly want to reflect what we think is going to happen, but understanding the possibilities and the probabilities about what's going to happen and what the constraints on that are, and what the bounds of it are, I think all are important things to understand between the agencies so that we can go forward. And I think we're going to agree on most of these points, actually. So thanks.

MR. SENSTAD: Good afternoon, Chris, Commissioners. I'm Alan Sanstad of Lawrence Berkeley Laboratory. I want to make a comment and raise a

question regarding, again, the disaggregation issue that complements Commissioner Weisenmiller's point about privacy concerns.

As a general rule in modeling, there is in many modeling domains, there are sort of ultimate tradeoffs between precision and uncertainty, accuracy and uncertainty, it's known as the "bias variance tradeoff" in technical modeling terms, and what it implies is that you cannot sort of, even subject to the resource constraints for getting data and so forth, you can overcome those, you cannot be guaranteed of sort of unlimited gains and verisimilitude in the model as you go down through further and further disaggregation. And that becomes an issue, I mean, sort of on general principles, but also there are -- one has to ask in the context of the purposes to which the CAISO puts the data because they're focused on risk and reliability management, because there might be a question about how much additional uncertainty, and therefore reliability and risk is built into the forecast as you go to further levels of disaggregation. So I want to flag that and ask by way of question about whether these sort of tradeoffs are being taken account of as you move forward in this disaggregation discussion.

MR. KAVALEC: Yes, definitely. It's one of the

key factors in deciding on an ultimate level of disaggregation where we want to end up in our forecast.

MR. VONDER: Hello. My name is Tim Vonder with San Diego Gas & Electric Company, and I'm from their Forecasting staff. I'm not going to take a totally flip side of Sierra's comments, but I would like to say that, when we approach energy efficiency and look at it as to how it's going to be folded into a forecast, we see there's a whole universe of potential for energy efficiency. And when we move, well, when we do the forecast of demand, it's fair to look at some or maybe a major portion of that energy efficiency savings. But as you move from the forecast to the resource planning phase, there is a subset of that energy efficiency that would be appropriate for resource planning, and you might say, you know, it's on a more conservative nature, rather than all encompassing. So the energy efficiency program planners, we feel, should have a large scope of energy efficiency to develop programs to meet, you know, so it's kind of like pie in the sky, you know, go for it. But as you move closer to resource planning, maybe a subset of that is ready to move on to that next phase. So we just want to say that, as we look at energy efficiency as it relates to the forecast, maybe there's two sets of -- or two scenarios that we might look at,

one with program planners in mind and another that would have resource planners in mind when we move from the Demand Forecast to the LTTP process. So I just want to keep that in mind.

COMMISSIONER MCALLISTER: Thank you very much. I really appreciate your comments. And I guess, so I'm dying to know what you would call the subset, what name would you give them?

MR. VONDER: I guess in the Regulations, I think it's Section 454.5, says that for resource planning purposes all energy efficiency that is to be considered for that exercise should be able to demonstrate that it's economic, feasible, and reliable. Now, that's kind of a pretty tough test, but that's what the resource planning phase expects.

COMMISSIONER MCALLISTER: So, Chris, could you talk to that as sort of how those comments sort of are or are not reflected in the plan that you presented earlier for the scenarios?

MR. KAVALEC: Well, they're not specifically, but I think that one way to approach this when we develop scenarios is in terms of levels of certainty, so the low scenario could be the most certain, and the high scenario would add in the less certain, so you could for example develop a low case where you include the next

round of IOU programs, along with the next two or three sets of standards that are just about approved, although not yet. And then for the high case, or the less certain case, then you would go further down the road and pick out future programs and future standards that come later.

COMMISSIONER MCALLISTER: Yeah, so looking past you have cost-effective energy efficiency, the evaluation shows that it's got TRC greater than 1, we don't need to get into those details today, but essentially some assumptions of what subset of the overall pie in the sky universe would fit into this sort of cost-effectiveness reliability envelope seems like there's a place for that in your process today, isn't that right?

MR. KAVALEC: Yeah, and I think Navigant could probably speak better on this, but you can develop scenarios where you vary the level of cost-effectiveness, so you have very highly cost -- if that's a word -- highly cost-effective measures in your low case and, as you move up to the high case, you have -- you're still above your threshold, but they're lower in terms of cost-effectiveness.

COMMISSIONER MCALLISTER: Okay, thanks.

MS. KOROSEC: All right, we have one question

from an online participant. It's Dina Mackin from the PUC. Dina, your line is open.

MS. MACKIN: Hi. This is Dina Mackin. To clarify one point about the question of the uncommitted forecast, we just wanted to clarify it's not so much a matter of bad connotations; the term "uncommitted" is inaccurate to a certain degree because of PU Code requiring the Commission to achieve all energy efficiency available as part of the loading order. So in terms of our commitments that go from one cycle to the next, the fact that we haven't authorized a budget for future funding is more a matter of the nature of our cycle and our program guidance than it is a term that suggests that we may not fund energy efficiency in the future.

Anyway, I think we've discussed that in the past, but my question is about a point that Commissioner McAllister had made earlier. He had indicated that there was a possibility that we would keep the incremental energy efficiency forecasts as a separate product that would be released on the side of the Demand Forecast. And I was wondering whether that is something that you guys are in fact seriously considering and what is the rationale for that.

CHAIRMAN WEISENMILLER: Well, again, you know,

basically the expected forecast will include that. There will be -- again, you can have a line that -- and typically I think we will have, like for ZEV -- we'll talk later today -- for ZEV we will have an expected low and high. And I would expect the expected to correspond pretty much to the Governor's goals --

MS. MACKIN: Uh-huh.

CHAIRMAN WEISENMILLER: -- so this is not the only one where there would be those pieces. Now, presumably over time as you're tracking stuff, you can do that. But, again, it seems like this is an important area, we're trying to flesh it out, we're trying to get consensus, so the more explicit everything is, I think the more likely we're going to get people lined up. But, again, certainly my recommendation typically is to use the expected case -- and for your expected forecast.

MS. MACKIN: So --

CHAIRMAN WEISENMILLER: As opposed to the low or the high case.

MS. MACKIN: So the expected case, could you clarify, does that mean the base case, or does the expected case include the incremental --

CHAIRMAN WEISENMILLER: Well, the expected case would include some incremental, and I think what we're struggling with is how much incremental, and there's

certainly -- you can get, for example, the proverbial how much is even Sierra going to bet his life that the Feds meet their goals for their Appliance Standards, you know?

MS. MACKIN: Okay.

CHAIRMAN WEISENMILLER: Or, as we look at our next round, again, you know, we have a pretty aggressive set of standards out there for appliance standards. How much of those do we include in a high case versus an expected case? Or a low case, for that matter. You know, what do we do at this point, for example, at this point on our battery charger standards, which are adopted and ready to go, the Feds preempt us in their current draft. We'll know better in July whether they're going to continue to preempt us, but are those in the expected case? High case? Low case? You know, which case do we assume we're not being preempted in? Obviously, there's a whole myriad of decisions like that which collectively -- it should give you some degree of comfort.

COMMISSIONER MCALLISTER: So I just want to respond sort of to your question, which presumably is more about the PUC portfolio than it is about the, well, certainly some aspects of the Standards are included in that question, but the question is how much is -- you

know, in the out years how we sort of figure out what of the voluntary type programs, or the broad gamut of funded programs that the investor-owned utilities are doing, and the PUC is requiring them to do, and each subsequent portfolio process, how we quantify what we expect to happen there and project it out, and have a conversation. In order to do that, we have to have a conversation with the ISO included in this conversation about, okay, well, what are they comfortable with? So I think in some sense, having it be within the baseline forecast, or somehow separate, which is the way it's been in the past, I have no commitment to doing it either way, I mean, I'd certainly as an energy efficiency advocate in much of my career, I would very much like to see aggressive energy efficiency going forward. But whether or not it's within the baseline forecast, we still need to have a conversation with the ISO about how much they believe it's going to happen, or what they have comfort around, so as part of their planning process. So they have to be a part of this conversation now and not just be expected to take what we give them as sort of, you know, perceived wisdom. So I think there is substance here that we need to have the conversation about during the course of the IEPR, and come out with hopefully what will be a consensus

opinion.

MS. MACKIN: Okay, that makes sense. And I don't know if you guys know, but we have been much more involved in conversations about this with CAISO in the last couple months, and they have shown that they are more committed now to modeling and incorporating in the incremental forecast into their forecasting models. So we've been working out a lot of these details with them, so we'll be continuing to do that.

COMMISSIONER MCALLISTER: Great, great. Thank you very much. Any other questions on the phone? Okay, that's it.

MR. WENG-GUTIERREZ: Good afternoon, Commissioners. My name is Malachi Weng-Gutierrez. I work in the Demand Analysis Office. And today I'm going to discuss the preliminary 2013 IEPR Electricity Demand Forecast Rate. I'll touch on the efficiency and self-generation components, and then I'll also talk about electrification assumptions.

So as with the CED 2011, I decided to use the Energy and Environmental Economics GHG Calculator as the basis of the development of these scenarios. I'm not necessarily wed to that as the basis of the rate scenario development, but that was my kind of first stab at developing the rates that I would start with the same

type of methodology that was used last time. I'm certainly interested in hearing people's perspective on other tools and other methods for developing these rates, and other things that might need to be included into the GHG Calculator, which are not innate to the calculator itself. So, again, I'm looking to get feedback on that, that tool certainly and what is involved with it.

Primarily for the GHG calculator, I looked at a couple of the input assumptions. These listed seven input assumptions that are what I varied across the scenarios, energy efficiency savings, the natural gas and coal rates, electricity demand, renewable generation, and combined heat and power, as well as demand response assumptions, and there's a carbon price element to it, as well. So these are the assumptions that I looked at, and I'll talk about most of these in detail in the following slides.

So I primarily looked at four different scenarios. The first scenario titled Scenario Zero basically has very little -- basically has low energy prices, high energy electricity demand, and low levels of EE, minimal PV, or photovoltaics. The photovoltaics, the amount in megawatts here, is consistent with the CEC 2011 low case. There is no additional CHP added, and

then the amount of new renewable generation that was included, this would be incremental to 2012 values, at 1,000 MW. So, again, consistent with the low rates that were developed for the CED 2011.

There were no incremental or increased demand responses over the base of calculation within the calculator, and there were no added costs for carbon in that evaluation, or in that scenario. Scenario 1 has the same energy prices, as well as the same electricity demand as the basis of the base calculation. There are low levels of EE, so it would actually be a consistent level with the scenario of zero, higher levels of PVs, higher levels of CHP, significantly increased levels of new renewable generation, but no initial demand response added to that over, again, the base included demand response.

In addition, in the final three scenarios, we've included carbon prices as a factor that will influence rates, and so that was with the -- Scenario 1 has our lowest set of prices for carbon included into that scenario. Scenario 2 is primarily the mid-case scenario, and then Scenario 3 is our high case scenario where we have primarily high energy prices, low electricity demand, high levels of EE, the highest amounts of PV and CHP, and also the highest levels of

renewable generation. In addition, there were additional five percent demand response available over the base levels, and the carbon prices were actually pretty significantly higher than in our Scenario 1 or 2 cases.

So this is a graph that just shows the four cases, in real terms 2010 dollars. These are aggregated statewide and basically weighted by consumption numbers from our QFER database. The outputs to the model, or to the calculator itself, is actually by planning area. So, again, I've had to aggregate them in order to show them here. And you'll notice that in the 2016 through 2018 timeframe in the high case, which is Scenario 3, there is that volatility that Leon had mentioned this morning having to do with natural gas prices.

Oh, and one other thing I wanted to mention here, the calculator itself only calculates values or projected rates up until 2020. So post-2020, what I've had to do is basically come up with a different rate. The rate that I ended up using was between two different rates. In the CED 2011 rates, the low rate, which again included very little by way of new power generation, new renewable power generation, as well as very little carbon and other things, was about .8 percent annual growth rate, was the general trend for that one. In

this Scenario 0, which has a different set of input fuel prices, the growth rate is about 1.7 annually over the 2012 to 2024 timeframe, so for 2020 timeframe. So I basically ended up using a value between the two, which would be one percent. So after 2020, I'm using a one percent growth rate as opposed to a trend from the prior four years, or say a constant value from the final year of the calculator, and so I would like to have some input as to whether or not that's a reasonable -- what might be an expected rate of growth in rates post-2020. And this, again, gets into the uncertainty there. Maybe there's a different growth rate for the high versus the low, meaning it would be influenced by things like a higher set of RPS standards that are implemented for the long term, or, you know, other things that could influence the rates that would be different across the different price rates that we're looking at, or the different scenarios.

So, again, here I've just used a constant one percent across all scenarios, but it could certainly be different, and it could certainly be influenced by a number of other things.

So I'm suggesting to use the Scenarios 1, 2 and 3, so disregarding the Scenario 0, primarily because these three scenarios have -- the inputs to these

scenarios are consistent with what Ivin had discussed this morning about those cases which we're trying to be consistent across all different inputs. So for example, one of the things these are consistent with is RPS is compliant in all three cases here, so we're making that assumption and it's consistent with work that's being performed by other staff in the Electricity Supply Analysis Office.

So I mean, I'm just going to touch briefly on these. The primary thing that I wanted to highlight here was that I think the energy efficiency component of it obviously, from that previously discussion, I think has to change. I'll be looking closely at what we end up putting in, or what we come to decide to put in. Right now, I'm using those numbers which were in the calculator from the last CED adoption, and I would expect that those would change even with this preliminary set of Demand Forecasts that we develop.

So I intend to change some of those values in the calculator, and it should change the prices slightly. So that's something that's kind of in flux right now, but I intend to be consistent with what we end up deciding would be an appropriate level of energy efficiency.

Demand response, the values that are in there

right now haven't been updated in quite a while. I hope to -- I've been trying to work with staff to get a better estimate of what might be appropriate over this timeframe, and I expect that we should be able to come up with some other numbers that I'll put in there, and so that would change slightly, as well.

The natural gas and coal prices are going to be consistent with what Leon had suggested they use for the preliminary, but as you heard from him as well, there might be some variation in those prices as we get closer to our final or revised Demand Forecast. So to the extent that we can make changes to the prices to reflect those changes, we'll do so. But there may come a time when we obviously can't make changes to our prices, and so we'll have to -- hopefully we'll be close to having the final sets of natural gas and coal prices at about the same time.

So one of the things that I did change from the last time was the base demand inputs, so in the original GHG Calculator they were using a set of Energy Commission Demand Forecasts that ran from 2008 to 2016, and I believe they trended it through 2020. But since we had recent adopted Demand Forecasts, we could put in the actual demand numbers, and that's what I put in, instead of using what was in there before. And the

second and third bullet points here just indicate the level of change in the inputs that resulted from the mid-case. So it went from 321,000 GWh to 285 in the year 2020. And then for the total peak load demand, it also decreased significantly from 74,000 MW to approximately 69,000 MW. So I think updating those numbers with our Updated Demand Forecast, or the CED 2011 Demand Forecast, significantly lowered those numbers.

Regarding the photovoltaic assumptions, or the PV assumptions, I'm using basically as inputs to this preliminary estimate, I'm using the outputs from the adopted 2011 CED values. So the three values that are listed under the preliminary 2013 IEPR are those which were developed and adopted in the CED 2011. In general, two of them are higher than the previous cases, but the high in the low demand case here does not reach the 3,000 MW value, which I believe is a goal. So that might be something that needs to be discussed and, if that's an important value to input, then we should hear about it. The reason why I am again using these three sets of values is that they are consistent internally with what other staff is using, so in order to be consistent with everyone, these would be the numbers that I could use. But certainly if we were going to

make -- if our office, our division is going to make decisions about using different cases that don't incorporate -- or, that do incorporate goals as opposed to maybe they lower the outputs, then that's something we need to hear about.

I'd also like to mention that, by using these outputs from the CED 2011, the range of values are much narrower, so at the end of the day, I think you're getting a cone that's actually shrinking in size towards the end of the forecast period. So that's another thing to consider is that maybe it would be valuable to have a wider range of values. But, again, I'm open to input. These values here are consistent internally with what we're doing, so those are kind of our preliminary set of numbers we're using.

For the Renewable Generation Assumptions, I'm basically using a set of latest CPUC-CEC generated scenarios. These were generated for the LTTP in the transmission planning process. They're much different than what were used in the last IEPR round, and they are all consistent with a compliant RPS future. So again, looking at the actual megawatts here, they are significantly higher than before, they're much narrower, as well, so that the final set of values may not be as wide as you'd expect from the last IEPR, but they are

internally consistent with what other staff is using, so, again, if we wanted to deviate from those, we should probably hear about it so that we can work with staff to make sure that we're as consistent as possible, or not, maybe we don't -- maybe for this exercise, or this activity, we include a set of values which are not consistent with everyone else's assumptions, but the ideal would be that we are consistent.

Very similar here with CHP, there was a recent report performed, a market assessment performed by ICF, which redefined CHP values. They had a set of three scenarios that they had developed. I used those values to populate the calculator, that's what you see below as the Preliminary 2013 IEPR Values. These are -- the one point that I did want to make was that, in the low demand case, in the prior CED 2011, the approximately 4,400 megawatts was what was identified as being compliant with the AB 32 Regulations in the original Scoping Order. Given the updated value for that, I think is the 4,800 value that I have down here for the Preliminary 2013 IEPR, partly increased because of line loss values. I think the original calculation used a static -- a single line loss value, and I've used more of a disaggregated line loss to calculate that number. So I think that in the low demand case that both of

those values would be consistent with the compliance with AB 32; the other two cases obviously, in the past we had zero values for CHP, but this time around I'm just using values which again are consistent with the scenarios developed in this Market Assessment Report.

So the next item would be the carbon prices that are put into the model. So now that there's the cap-and-trade regulation going forward, we would have a number of auctions. The base auction price that we're using is the $10.71 per megaton CO_2 equivalent ($MTCO_2e$), that's kind of the start for the prices in our time series. We increased that for the lowest price series, or time series, by CPI plus five percent, which is what the minimum is supposed to be for the rate increase, or the prices to increase. Then, in our mid-case, we used 150 percent of that low, and in our high case we used 300 percent of that low case, so CPI plus five, 300 percent of that would be our high case. Given that there's a auction or a reserve, a three-tiered reserve that is designed to mitigate the costs, high costs of, say, an auction set of values, we're using that as the high cap, so in no time during the forecast would it exceed the third tier reserve price of $50.00 per $MTCO_2e$. So in 2020, the prices are $20.00, $29.00, and $50.00 for the high, mid and low demand cases, respectively.

So this is just a table that shows all of the inputs for the three different cases. If you recall back to the previous slides, you know, some of the CED 2011 values were much lower, so again overall we're having a narrowing of the inputs for the three different cases. You know, if people have suggestions about how to change those, that would be great or, again, if there's a different calculator that could be used to come up with some of these numbers or methodologies, that would be great. I think in the near term, our numbers are fairly -- the growth rates that we're seeing are fairly consistent with some of those that have been floated in either the CPUC adopted cases, or general rate cases, or in rate analyses performed by the utilities themselves.

So, again, the outputs for the Calculator are by utility, so I just wanted to show the distribution of rate increases over the timeframe that we're looking at by the utilities. So LADWP shows the largest growth, it's pretty significant, same with SMUD. These are the percentage growths, so the actual rates would obviously be different, so certainly not saying that -- in this graph, I'm not representing that SMUD's rates are higher than someone else's, it's just that the rate of growth from their current levels is fairly high.

So what I'd like to do in the future, or in the near term potentially, given time and resources, I think is look more closely at the energy efficiency values that are in the Calculator, make sure they are consistent with anything that we come up with in the near term, evaluate the costs of the new renewable generation; these are the costs that ideally would be used by the Electricity Analysis Office, making sure they are consistent with what they're using. I'd like to take a look at the impact of the Preliminary Demand Forecast on the outputs of the Calculator, so as a kind of iterative process, whatever we develop in our Preliminary Demand Forecast, I would have as inputs, so there could be a whole slew of things, CHP, PV, all those things might be adjusted by whatever our input is for our Demand Forecasts, and so I'll look at how that influences the outputs, and then refine the Demand Response values. As I indicated before, I think staff is already looking into those, so hopefully they'll have that relatively soon and I will be updating those values accordingly. And then I think there's some complexity to the cap-and-trade regulations as far as allotments and allocations and revenue uses, which could impact certain sectors differently. So I think taking a closer look at that and how the revenues are expended to

mitigate the impacts to ratepayers, I think has to be considered. So I'd like to spend some time doing that as well to see how that might influence the final tariff rates there, or the rates that are shown here. And that is my final slide for the electricity rates.

The Electrification Assumptions that we have this time around, I think primarily we're going to be looking towards the Transportation Division for guidance on most of these. For CED 2011, the Demand Analysis Office received electricity demand for Plug-In Electric Vehicles which, you know, I think the low case was exactly compliant with the ZEV mandate, and then the higher cases had higher levels of electricity demand from higher market penetrations of PVs. So whatever Transportation decides -- however they decide to address the ZEV mandate and incorporate that into their Demand Forecast, we would like to have that as our inputs to our Demand Forecast for electricity.

In addition to the Plug-In Electric Vehicles, we're obviously looking at Fuel Cell Vehicles which could be a major electricity demand if it is a primary method of ZEV compliance, so they might play a larger role than they have traditionally. It all depends on how transportation decides to handle the ZEV compliance.

Port electrification, the ARB has the At-Berth

Regulations, which limit emissions at the ports, and so there is a trend towards more electrification at the Ports, so it would be great to receive some information on that and estimate that demand over the timeframe that we're looking at, as well as high-speed rail, which is another potential high energy demand source there. So, again, we're going to I think look towards Transportation to determine how best to address these elements, and then incorporate them accordingly into our Demand Forecast -- truck stop electrification as well falls into that category.

The Bay Delta Conservation Plan, that's something that I think we need to spend a little time looking at. I think it could increase ag load, I'm not sure to what extent, but I think it will be constructed within the timeframe of our forecast. So depending upon how significant it is, it may have to be included in our Demand Forecast in some way or another. So those would be my suggestions for electrification.

And with that, I think I'm done, so I would be happy to answer any questions you have.

COMMISSIONER MCALLISTER: Thanks for that. That was a clear presentation. Just a couple of questions, one kind of a comment first.

So there's lots of talk about sort of the

mandates on the electric sector and how it's going to force rates up, and your last few slides I think indicated that many of those issues, you know, incorporation of renewables, figuring out -- well, lots of different influences that the utilities are having to invest in their infrastructure, and the RPS mandates, things like that are going to force rates up, I guess. Is this upcoming rates issue, are all of those factors accounted for in your modeling as far as you know?

MR. WENG-GUTIERREZ: Yeah, to the -- well, they are to a certain extent. I think, as somebody from the PUC mentioned to me, it really is going to be important to see near term, making sure that we get 2013 correct so that the growth rate that we're observing is appropriate over the timeframe. Right now, I've gotten information from the utilities, for some of the utilities, the estimated 2012 value which I grow from, but I think that there are plenty of activities in rate design right now that are coming up that we will have to try and incorporate, you know, as best we can. So I'm not going to say that they are incorporated because I think there's a lot happening, but I think we're keeping an eye on it and trying to incorporate them as we can.

COMMISSIONER MCALLISTER: And so you're presumably holding hands with the PUC on this to make

sure that your sort of initial -- so that your understanding of the dynamics, what might be coming up so you can work that into your scenarios as actually based on what is happening in that world?

MR. WENG-GUTIERREZ: Yes. I've tried to reach out to them and keep them close to my ears so I understand, yeah, what's occurring there, as well as what recent activities have been adopted, and what rates have been adopted so that it is reasonable.

COMMISSIONER MCALLISTER: Okay, great. So my other question has to do with the photovoltaic adoptions, or customer side PV, and it seems like it's not only driven by sort of average rates, but it's driven by rate design. And so I'm wondering how well your sort of high, mid, low scenarios are going to capture the dynamic of what is really going to influence customer side, say, solar for example. Like you said, there's a lot of rate design activity going on that is going to outlast this IEPR. But I'm wondering if you've thought about that in designing your scenarios and picking your sort of gigawatt high, medium and low scenarios.

MR. WENG-GUTIERREZ: So for the PV, again, what I did was I used the outputs from the CED 2011.

COMMISSIONER MCALLISTER: Uh-huh.

MR. WENG-GUTIERREZ: So as you say, I mean, the rates could have an impact on that and I haven't necessarily discussed that with our staff who has done that estimate to see how, you know, overall rates increases my influence -- his outputs.

COMMISSIONER MCALLISTER: I'm thinking like bundled rates present one view and the sort of average cost per kilowatt hour kind of thing, but that really belies a much more complex and kind of rich story of like, okay, well, your top tier rate, if it's really high then that's really going to drive PV adoption in, say, the residential sector. So I think the two don't necessarily go hand in hand here.

MR. WENG-GUTIERREZ: Right. And I -- although this is the base electricity rate that's developed for the inputs to the different models, I'm not sure how our PV model handles those values and how he -- I know that he is intimately knowledgeable of the tariff rates and things that are associated with, you know, with the adoption of PVs, I'm just -- I'm not sure how he handles that. Maybe Chris wants to answer that question.

COMMISSIONER MCALLISTER: No, that's fine. There's also the backdrop of the Governor's 12 GW distributed resources goal and kind of -- so that's also policy that we're trying to aim towards, and I just kind

of want to make sure that you're looking at all of those things together.

MR. KAVALEC: Yeah, so a couple things. In our predictive models for photovoltaics, those taken into account not just average rates, but rate structure. And on your comment on goals for PV, the way we look at it is our job is to predict penetration, rather than assume any goals are met, so I make that point.

CHAIRMAN WEISENMILLER: Yeah. Actually, just a couple follow-up things while you're there, Chris. I was just talking to Commissioner Florio on, obviously at this point things that are potentially in play on net metering and rate design, and certainly hopefully the Energy Division staff involved in the DAWG (Demand Analysis Working Group) on this also can help provide some insight into the rate issues, the CSI issues, the net metering, and the rate design questions. I guess the net metering study is expected in May and the rate design probably more fall. So there's going to be a bunch of things that are going to be up in flux up until the time that we adopt, I think. But certainly, just as we're trying to have a pretty collaborative effort on the energy efficiency side, that this will be one where it will be very good to hook in the PUC staff. Similarly on the overall rate issues, I know they've

done some analysis of what they're forecasting rates to be going forward, so again it would be good to make sure that is -- you know, again, we'd get the benefit of that analysis in your thinking.

MR. WENG-GUTIERREZ: I actually have reached out to the PUCs and I know that there's a report coming out relatively soon looking at near term rate implications. So, yeah, to the extent that we can incorporate it in the timeframe of our Demand Forecast, I think we will do that.

COMMISSIONER MCALLISTER: Is this E3 tool that your output -- I think this is essentially two ways to state the same output, right? It looks like slide 5, maybe, and then the next to last slide where you've got disaggregated gross percentages by utility?

MR. WENG-GUTIERREZ: Right, yes.

COMMISSIONER MCALLISTER: That's the same tools.

MR. WENG-GUTIERREZ: Exactly. So --

COMMISSIONER MCALLISTER: Could you describe that tool? Is it something that the PUC also uses? Or it's something that is --

MR. WENG-GUTIERREZ: Yes. So it was developed for the PUC's activities by E3, so E3 was under contract with the PUC to develop it for their activities. I think the last version that was put out was October of

2010, I think, so it hasn't been updated in a little while. There are other tools out there that are more -- that have been developed more recently but, again, to the extent that we can use them to develop these rates, I'm not sure. This certainly is a tool that allows us -- that has been developed for the PUC -- that allows us to get to these values and includes all the AB 32 kind of Regulations.

COMMISSIONER MCALLISTER: Just to be clear, these are 2010 dollars, so that's a real increase, right?

MR. WENG-GUTIERREZ: Yes, these are real increases, that's correct.

COMMISSIONER MCALLISTER: So I think we can go to questions in the room and then on the phone.

MR. WENG-GUTIERREZ: So if there are any questions in the room?

COMMISSIONER FLORIO: Just a couple questions. On the CHP assumptions, is that new CHP, or is that the sum of new and existing?

MR. WENG-GUTIERREZ: I believe this is the total new CHP.

COMMISSIONER FLORIO: Total new, not including existing?

MR. WENG-GUTIERREZ: Right. And I think that's

consistent, again, with what the AB 32 Scoping Order said that they would have to be new CHP over that timeframe, so these are all new CHP -- through 2024.

COMMISSIONER FLORIO: And PV on the earlier page, is that statewide, or just Investor-Owned Utility?

MR. WENG-GUTIERREZ: This is statewide customer side capacity, yes. This is statewide.

COMMISSIONER MCALLISTER: Again, this is also in 2020?

MR. WENG-GUTIERREZ: Actually, this is for 2020.

COMMISSIONER MCALLISTER: And this is cumulative total? Or --

MR. WENG-GUTIERREZ: This could be -- I would have to check to see whether or not this is -- this is the value in that year, so it is cumulative total, yes.

COMMISSIONER MCALLISTER: Okay. So the highest scenario you've got for the IEPR would be in 2020, you said?

MR. WENG-GUTIERREZ: Yeah, these numbers are for 2020.

COMMISSIONER MCALLISTER: Okay, so 2,582 -- I'm thinking that seems low, but I'd have to -- maybe we should ask the world what it thinks and talk later. And this is statewide, so we have IOUs with some and POUs with some?

MR. WENG-GUTIERREZ: Yes.

COMMISSIONER MCALLISTER: Okay. It would be good if you could sort of dig into that a little bit and figure out where those numbers are coming from.

CHAIRMAN WEISENMILLER: Also, I don't know if you have a sense of the breakout between IOU and POU?

MR. WENG-GUTIERREZ: I don't.

CHAIRMAN WEISENMILLER: Or ultimately, I assume you've got a backup table that, when it's posted, people can see?

MR. WENG-GUTIERREZ: Yes.

CHAIRMAN WEISENMILLER: That would be good.

COMMISSIONER MCALLISTER: Okay, I think we --

MR. WENG-GUTIERREZ: Comments from the room? Or questions from the room?

MR. TUTT: Good afternoon. Tim Tutt from SMUD. And, Malachi, I just wanted to follow-up a little bit on the photovoltaic assumptions and that table. The first thing is, I'm assuming that these are the actual contribution to system peak estimates, rather than the nameplate capacity of the PV?

MR. WENG-GUTIERREZ: It's installed.

MR. TUTT: Installed capacity.

MR. WENG-GUTIERREZ: Yeah, installed capacity.

MR. TUTT: Okay. And then the second question

is, you've been running this predictive model for a few years now, do you have a sense of how it has worked in comparison to the actual installed in the last few years?

MR. WENG-GUTIERREZ: I had thought that, since we were comfortable with the results that it was performing well and that we were expanding our analysis to commercial, but we do have staff that performs this actual analysis that -- do you want to answer?

MR. GAUTAM: My name is Asish Gautam. I work on the DG side for the Demand Analysis Office. As far as the performance of the customer adoption model, it seems to give reasonable adoption rates compared to the last few years of the history, so….

MR. TUTT: Okay, thank you. And then, Malachi, shifting to carbon price assumptions, it's my understanding from the cap-and-trade regulations that the price containment reserve tiers also escalate at inflation plus five percent, and so I'm wondering if you are reflecting that assumption -- well, if you're not reflecting that assumption consciously, or is that just something that slipped through the cracks?

MR. WENG-GUTIERREZ: Yeah, I have not -- I did not increase that for that reserve tier. So that is something I can do.

MR. TUTT: Okay. And then shifting to the rate increases, you talk about rate increases from the E3 calculator and show SMUD having a fairly significant rate increase projection out to 2024. Are you going to provide detail from the E3 calculator as to where those rate increases come from?

MR. WENG-GUTIERREZ: Sure. I can provide the actual E3 calculator with the values that were input, and then it should break it out how it generates that increase, I'm sure.

MR. TUTT: All right, thank you. And then lastly, on your last slide, electrification, I guess I'm wondering two questions, one, what kind of electrification comes from Bay Delta Conservation Plan?

MR. WENG-GUTIERREZ: Well, it would be water pumping.

MR. TUTT: Okay. And then are you looking at any other electrification in your forecasting, not just from transportation or water pumping or high speed rail, but fuel switching, for example -- of any sort?

MR. WENG-GUTIERREZ: These were the ones that we planned on looking at, but if there are others, we'd certainly be happy to look at them.

MR. TUTT: Okay, thank you.

MR. MEYERS: Richard Meyers with the California

PUC. On the slide that shows the percentage increases for the electric rate, is that an average increase across tiers? Or is it for any particular tier?

MR. WENG-GUTIERREZ: Right, so the GHG Calculator doesn't calculate a specific tier, it's not associated with specific tariff, so it's just the total system-wide aggregate value.

MR. MEYERS: So if you assume that lower tier electric rates are capped, these increases would be achieved on the upper tiers, so the increases on the upper tiers would be far greater than what you see here, is that right?

MR. WENG-GUTIERREZ: Yes, right, as well as by sector. So it could be borne differently by different sectors, as well. So that's something that I indicated I think I need to look at a little closer to really understand how it's changing. Certainly for like cap-and-trade regulations, there may be things that mitigate the prices across certain sectors, so the costs might be borne more so by other sectors, as well. So I definitely know that there are differences across sectors, as well as tariffs. So to the extent that we can disaggregate that appropriately, we will.

MR. MEYERS: All right, thanks.

MR. WENG-GUTIERREZ: If there are no more

questions in the room -- oh, all right, no other questions on the line? Okay, thank you.

MR. OLSON: Commissioners, my name is Tim Olson. For the people in the audience here, I'm the Manager of our Transportation Energy Office.

I'm going to do some overview stuff first, and then we will invite Gerhard Achtelik from the Air Resources Board to talk about this mandate, and then Ryan Eggers will talk about our crude oil fuel price forecast.

Transportation is not as advanced as electricity and natural gas in the forecast work. We're not going to go through the assumptions like the other groups have; we're going to touch on where we are in the process. For the most part, we're going to be in probably the June timeframe to have the same discussion like we're having today on electricity and natural gas. But we are doing bi-weekly meetings with both of those offices on how we're coordinating common assumptions, and you'll see, as you see today, that there are cross-overs from electricity and natural gas and the transportation.

But just briefly, just to touch on how we forecast California fuel demand, it really is we try to figure out what the fuel consumption is, that's what

we're projecting into the future. For the most part, that's been petroleum in the past, we want to know to what extent other fuel sources, electricity, natural gas, either biofuels, are also options.

And the approach we take, it's a heavily dominated modeling work for the demand. We use things like consumer choice surveys, data purchases, data obtained from Caltrans, Federal DOT, Bureau of Automotive Repairs, the Department of Motor Vehicles, Board of Equalization, we're gathering information from lots of sources. And because this is a very diverse -- as you can see on this slide -- diverse in terms of vehicle sector. There are lots of different models. We linked that together with a program we call Dynasym, it's a broader model that tries to link all these demand factors together. And, you know, just look at some of these areas. Freight and Service alone, there are several different categories -- long haul trucks, package delivery, beverage delivery, refuse trucks, utility bucket trucks, in addition to the urban and inner city transit school buses, lots of different things to keep track of. It's very difficult to get all that data and get it currently. Some of the models have different eras, too, some of them are fairly new, some are 20-30 years old. So we're constantly doing

validation to see how accurate we are.

We couple this demand work with what we call Vehicle Attribute Analysis, and that's typically a contractor; we're about to hire Sierra Research here to help us on that, identify some of the factors related to vehicle model performance, characteristics that are used to help in this demand. And so I think, you know, that's kind of the significant effort that's going on with lots of models, lots of staff.

To give you kind of a glimpse of the other elements of this analysis, I'm going to just kind of quickly go through this again. We're looking at June, July, and August when we're going to have this work done. And you're going to hear later from Ryan about the fuel price -- petroleum fuel price forecast, and that's kind of the initial forecast that we're using. We go through a couple iterations of that.

We will also do this what we call Developed Supply Demand Balance. We get information from lots of different sources, it's really an assessment of supply outlook, lots of different sources -- oil companies from our PIIRA database, some subscription data that we buy, and of course we've got to have the demand information here to complete all that work. And that's, again, later this spring, early summer. In addition, part of

that work is we're evaluating the impact on energy infrastructure, primarily petroleum, oil refineries, pipelines. So that's kind of -- those are elements coming up in the near future.

In addition to that, we are going to spend a lot more time this year on what we call developing alternative fuel scenarios, and there's a lot of work underway to combine staff and in hiring contractors, and interactions with several agencies.

December 2011, our Executive Director, Rob Oglesby, at the ARB Board Meeting in December of 2011, agreed that the CEC would work cooperatively with the ARB and other agencies to jointly develop these alternative fuel scenarios, going into the future. And I can touch on some of that work. And since then, we've had some pretty significant trends occur that many of us are aware of, Federal incentives declined, some of them have come back, and the Fiscal Cliff Bill. We've had some pretty significant progress on our AB 118 incentive programs, same thing with the ARB's element of that.

We've seen some new things happen on regulations, or maybe the maturing of the regulations, the Low Carbon Fuel Standard, Cap-and-Trade, Clean Fuels Outlet, RFS2, and the National Ambient Air Quality Standards, these are regulations, they're factors that

are going to affect California right away, right now, and up to the National Ambient Air Quality Standards, significant criteria pollutant reduction required in 2023, particularly affect the South Coast Air Quality Management District and San Joaquin.

And I'd like to just kind of go through a couple of examples of what we're doing in these areas. So for example, with our scenarios, we're definitely going to look at what we described here as a crude oil price forecast, very similar to the natural gas and electricity -- a high/low and a reference case. We're looking at milestone years of 2015, 2017, 2020, and after 2020. And a lot of that has to do with some regulations in the near term, 2015 a lot of things in the marketplace change, or pretty much government intervention could change. For example, incentive funds expire in 2015, there are lots of effort underway to extend those. Some of the Federal tax credits and like the biodiesel credit, lender credit, expires in 2015. LCFS work looks like there's some -- that's when we're expecting to see maybe issues with compliance or ability of credits to be available in that timeframe. And that's when the oil refineries are targeted, and their first year of kind of targeting is 2015 under the Cap-and-Trade Regulations. And so we want to look at 2015,

even though it's a short period of time, what's going to happen from here until then, and then 2017 is something the ARB asks us to look at. Related to -- if you remember in the Low Carbon Fuel Standard, five percent of that 10 percent carbon intensity comes in the first seven years, and then the other five percent of the 10 percent comes in the last three years, so 2017 will be a key point for that.

We've engaged several outside parties in this process, last week meeting with ARB's Deputy Executive Officer to go over how that interaction occurs on the Low Carbon Fuel Standard and the ZEV mandate and climate change activities. We have ongoing interactions with U.S. DOE, U.S. EPA Region 9, Washington, D.C. EPA, and RFS2, and the Michigan Regional Office for EPA, that's where a lot of the electric vehicle research occurs. Of course, California Public Utilities Commission related to electric vehicles primarily, Nancy Ryan and Adam Langdon; CAISO, Heather Sanders there is directing the Vehicle to Grid work; and of course the Governor's Office has asked us to, as part of the Governor's Zero Emission Vehicle Executive Order, to update the forecast on electric vehicle, ARB, CEC, and the other members of that Executive Order.

We are coupling that with other studies that are

going on. David Green's analysis, *2050 Vision for Zero Emission Vehicles*, should be out, that's funded by ICCT, that's Alan Lloyd's new NGO organization. Quite a few other studies -- E3, other groups that we're drawing upon in terms of forecasts. Some of them are related to just one type of vehicle, some of them are broader.

We also are coupling that with very significant interview data gathering process with several companies, some whom have received money from the Energy Commission under the AB 118 Program, but many that have not, but are willing to share their information on, for example, with biofuels, when are the projects going to be on the ground, what's the magnitude of their development and production. We're asking questions about how they are financing the projects. We're trying to find -- get more reality on when these projects are contributing something to these overall public policy goals, whether it's the Low Carbon Fuel Standard, AB 32, petroleum displacement, the whole host of Bioenergy Action Plan, all those different kinds of policies, we're trying to do this work to sum up where these alternative fuels are in those timeframes that I talked about.

And maybe to give you an illustration of that, about three weeks ago a group of us met with kind of a small sub industry of the biodiesel industry, and this

is the Yellow Grease/Brown Grease/Tallow people; we think this is probably the early market and there's two projects that are operating in California, we met with them individually and, as a group, found out that there's an optimum size of that plant, there's a business model that's been developed, there's still some deployment challenges. We think there's a number we can bank on there in terms of what will be contributed from that sector and how that business works with its supply chain, in this case restaurants, rendering plants, and the whole host of vehicle fleet people that are in essence kind of lining up with that industry.

We're expecting to do some of the same kind of work in several other biofuel areas and, of course, with electric vehicle hydrogen, natural gas. Let me just mention, on hydrogen, because we are part of the California Fuel Cell Partnership and spent a lot of time on that Hydrogen Roadmap, that's a central part of the scenario for that fuel. There are other studies that the Energy Commission was a participant in, or have reviewed, National Petroleum Council, NRC studies, of course we've got the ZEV mandate scenarios, commitments from automakers through the ARB program for hydrogen and also electric vehicles.

The extension -- reauthorization of AB 118 has a

relationship to the Clean Fuels Outlet. We are looking at all these different factors. And then we're also coupling this hydrogen work with interviews with automakers and infrastructure companies, again looking at how to verify when they're going to have, in the case of automakers, where they're going to sell their vehicles, or lease them, when that occurs, and what numbers, basically kind of doing a match-up to previous forecasts. And I'm glad that Malachi went through that slide on the kind of electrification. There's a large part of transportation on that, but just to give you -- I think I mentioned the ZEV mandate commitments are a key part of that from now to 2020, and then 2025, different scenario projects are underway. We will be working with the Governor's Executive Order team on updating that electric vehicle scenario, and have agreed with ARB, CEC and ARB, doing joint interviews with automakers so that automakers are not over-surveyed on any of these areas. Nancy Ryan, PUC are also part of that, she's interested in the electric vehicle aspect. And of course, we're also drawing on the Plug-In Vehicle Collaborative, the 38-member group. And I also want to mention that our interviews will also include utilities in that process through Cal ECT.

And also, the way we're handling the items that

Malachi raised, meetings with the High Speed Rail Commission, Ports of L.A. and Long Beach, primarily, and several fleet associations regarding APU's, Auxiliary Power Units on trucks, and the truck refrigeration unit, we think that could be a significant transfer to electricity.

I mentioned the biofuels. In essence, I'll give you a feel for the kind of questions we're asking and then I'll just pretty much go to this last slide. But in essence, we want to know the technology fuel commercial status. We want to know the size of the projects, if it's a fuel production, how much you're producing and when. We want to know project locations, potential replications. We want to know -- we're asking a lot of questions about business models, we're asking questions about how they're going to compete in a marketplace with the price maker at that point in time. We're looking at asking questions about deployment challenges. And we're also asking questions about what kind of research and development has to occur.

So here's the other point of this, this work is pretty much a horizontal activity throughout this agency, our Transportation Energy Office, our Emerging Fuels and Transportation Office, the R&D Division, to the extent that there's any kind of interaction with

power development, the Renewable Energy Office for the most part, and of course our scenarios are shared and agreed to between the Energy, the Electricity and Natural Gas Offices, and our Transportation. And it's horizontal to the extent that it also goes outside our boundary of our agency to other agencies.

And then the schedule we're looking at here is pretty much between now and July is when we are doing most of this work on the supply demand balance, the scenarios, and expect to have I think at the end of June the workshop there, we will go through the demand forecast assumptions and then, by August, have this work done. And that's kind of where we are in this.

COMMISSIONER MCALLISTER: Great. Thanks a lot, Tim. I'm really looking forward to hearing how those conversations with the grease and tallow people go. No, but seriously I think your overview is good, the plan is good, obviously a lot of the devil is going to be in the details down the road, so how your modeling process and tools shape up, I think, is something we obviously will talk about at the opportune time.

I guess on specific question, I'm wondering, are you going to be using that information, your survey work, and asking about the business models and the challenges, the R&D needs, trying to get at numbers and

dollars of investment need for different aspects of the infrastructure that's required? You know, the electricity maybe gets a little over in the electric sector, but for biofuels and other fueling infrastructure, it seems like a pertinent question we would want to try to shed some light on.

MR. OLSON: Yes, that's one of the key outcomes, is what kind of investment is required, and there's a spinoff of that, so in these meetings I'm bringing staff from our Emerging Fuels Office that manage the investment fund there, and we're basically posing this question to what extent are government incentives and what mechanism of that incentive are needed and in any of that total investment needed. And that's what we found with that biodiesel group, that within three years that whole thing shifted. It used to be we need storage and blending terminals, now it's a feedstock assurance issue, and in that case it's almost like the fuels are basically -- the prices are set and dictated basically on an almost daily or weekly basis. It's difficult to take that to the bank for any kind of project financing, that's a deployment challenge that needs to be addressed, but we think there's something there because you look at some of the other parts of the biofuel industry and that's what's happened -- three-year, five-

year, seven-year fuel contracts for the feedstock, and there's a potential for that to happen. But we definitely want to know, you know, if this is a $100 million investment, how does that happen?

COMMISSIONER MCALLISTER: I guess I would say the flip side of that also is, you know, some of these feedstocks you might, you know, with tallow, for example, you know, maybe there's a finite amount of tallow in the state, and once you've kind of got all that supply locked up, what does it look like going forward? You're not going to have sort of more slaughterhouses to supply us for biofuels. So I think understanding the limits, sort of the scale and the limits in scale on some of these specific feedstock issues is really important for us to understand the whole.

MR. OLSON: In that example, it's based on population, so much gallons of brown grease and yellow grease per person, per year. And you're right, there is a limit and we think that right now that's about 100 million gallons which -- and it looks like the optimum size plant, it may be 10 million gallons per year, so that's 10 plants; there are two right now.

COMMISSIONER MCALLISTER: Okay, great. I'm really looking forward to that work. Thanks.

MS. KOROSEC: Do we have any questions from the audience? All right, we have no questions online, so I think we'll move on here.

Our next speaker is Gerhard Achtelik from the ARB.

MR. ACHTELIK: Thank you. Thank you for inviting me here. I'm filling in for Analisa Bevan and I'll be giving you an overview of the Zero Emission Vehicle Regulation.

Almost a year ago, or just over a year ago, the Board adopted a comprehensive package of regulations that was intended to ensure that the cleanest vehicles would be available for the consumer. And that included the Low Emission Vehicle Program, which is your standard internal combustion vehicles; the Zero Emission Vehicle Program, which is the Zero Emission Vehicles which today includes the hybrids and the plug-ins and fuel cells and battery only vehicles; and the Clean Fuels Outlet Program, which is intended to ensure that the infrastructure is in place once the vehicles are here.

This is I think a pretty well-known graph. It's a modeling scenario that came out in 2009, and it represents one way of getting to our target of reaching an 80 percent reduction in greenhouse gases by 2050. And one of the things that has to happen in order to

achieve that is that, by 2050, the majority of our fleet has to -- our light-duty fleet has to be zero emission, electric drive or zero emission. And by 2040, the majority of the light-duty vehicles that are offered for sale have to be Zero Emission Vehicles. And that's based on the half life of a vehicle that today, what we say a half life of a vehicle is 15 years, that means if you buy a car today, half the cars that we buy today will still be around 15 years from now, so we have quite a challenge to meet a complete turnover of vehicles by 2050.

And what is the Zero Emission Vehicle Regulation? It represents a combination of battery electric vehicles and Fuel Cell Vehicles, but it also represents technology development vehicles, the plug-in electric Hybrid Vehicles, the conventional hybrids, and the clean gasoline vehicles. And those bottom two, the conventional hybrid like your Toyota Prius, or Honda Civic, the Ford vehicle, those are available today already. Also clean gasoline vehicles, those are called in the regulatory terms, those are Partial Zero Emission Vehicles, those are available today, and the PZEVs especially represent a large portion of the fleet, and they run anywhere from something like a Ford Focus to BMW3 Series, they're in a variety of cars. And those

bottom two cars will only stay in the Zero Emission Vehicle Regulation through 2017. After that point, all the cars that qualify for the program have to have an electric drive component.

And the ZEV Regulation, although it was developed in 1990, it has changed a number of times, it has been very successful. We have over 10,000 battery electric vehicles, and that 10,000 number hopefully sounds small to all of you, and it is, because it's based on our 2011 compliance inventory. The automobile manufacturers have until May of this year to give us how they comply for 2012, so we're just giving you the 2011 numbers. These are the numbers that we know as a fact how they have complied in 2011. So there have been a number of Fuel Cell Vehicles, a number of plug-ins, over 450 conventional hybrids since they first started rolling out in 1999, and over two million Partial Zero Emission Vehicles. Those provided tremendous health benefits to the residents of our state.

How did we change the regulation a year ago, back in 2012? What you can see here on this graph is that, by 2025, 15.4 percent of the vehicles offered will have to be either a pure ZEV, or a Plug-In Hybrid. And compared to where we were before, you can see at the bottom of the chart around 40,000 and 50,000 vehicles,

that's where the regulation stood before. So there was a tremendous increase in the number of Zero Emission Vehicles that the automobile manufacturers are required to bring, and that's intended to help ensure a commercial market, part in order to get cost reductions we need to have the number of vehicles. And it's also based on where we saw the technology going and the advances that were being made.

This is a possible compliance scenario that through 2025, we expect a predominance of the Zero Emission Vehicles to be plug-ins, something like a Volt, or more BEVs, and then some fuel cells. Now, these numbers here represent a minimum compliance scenario, these are not what the automobile manufacturer could comply with, they could actually produce more cars, and the Air Resources Board and the Energy Commission have conducted surveys of the OEMs for Fuel Cell Vehicles based in part to make infrastructure projections, and the initial projections for those are certainly higher for the 2017 timeframe, but these are a minimum number of vehicles that are required to meet the regulation based on historical roll-out of vehicles.

This gives you roughly the ratio that roughly 30 percent of the Zero Emission Vehicles are Fuel Cells and 70 BEVs through 2025, and we do see after 2025 a

transition happening where an ever-increasing share of the Zero Emission Vehicles will be Fuel Cell Vehicles.

This graph represents the plug-ins, so if you're looking at the Electric Vehicle charging needs, this is an annual sale of plug-in vehicles, or, in this case, I mean both the Hybrid Vehicles and the Battery Electric Vehicles. And by 2025, over 1.4, roughly 1.5 million Battery Electric or Plug-In Electric Vehicles will be on the roads in California.

And like I said, earlier the numbers were based -- the ZEV Regulation was strengthened in part, you know, for a number of reasons, 1) to meet our Ambient Air Quality Standards, and another, to meet our Greenhouse Gas Reduction Quality Standards, and because we saw the technology cost reducing, but as the production increases, historically it's proven and the forecasts say that the costs of the cars go down, so as volume goes up, production cost decreases.

One of the major changes that happened last year was that the intermediate vehicle manufacturers were also made part of the ZEV requirement; the original six were Chrysler, Ford, GM, Honda, Nissan, and Toyota, and then a year ago, starting in 2018, BMW, Hyundai, and the rest that are listed here, will also have to come out with a Pure ZEV Program. And what is left of the four

independent volume manufacturers, Jaguar, Rover, Mitsubishi, Subaru, and Volvo, they will be able to comply strictly with the Plug-In Hybrid, but they could also develop a Zero Emission Vehicle.

So the numbers increase because the vehicle regulation has become stricter, a higher number or percentage of the fleet has to be zero, but they also increase because more automobile manufacturers are required to deliver Zero Emission Vehicles.

And then why are we doing this? You know, we're looking to transform the fleet. We need to reduce greenhouse gas emissions, and we also need to reduce the smog emission or criteria pollutant emissions. The name comes from initially the criteria pollutants, and probably all of you know this, but they have Ambient Air Monitoring Standards, and so the reason we reduce emissions from vehicles is to ensure that we can meet the Ambient Air Quality Standards.

So by 2025, we expect the ZEV technology to be commonplace with multiple choices, and that's part of how the consumer will adopt this, as having many platforms to choose from. And we need to have the infrastructure in place, either through the Clean Fuels Outlet Regulation, or through programs like AB 118.

That's the end of my presentation. Do you have

questions?

COMMISSIONER MCALLISTER: So thanks very much for that. I really appreciate your being here. And the cross agency work, I think, is really pivotal and essential for making sure that our foundational work here in the IEPR, in the forecasting is in place for everybody to be able to use, and also just building the team that we need to make all this happen going forward. I mean, your last couple slides of 2025, you know, we have 2018 that we're hopeful the marketplace is going to have product out there, and 2025, we really have to be able to look back and show that we've accomplished a lot. So I think that's important.

I do have a question about your slide 8. I'm just -- I'm not sure I'm understanding what we're looking at there.

MR. ACHTELIK: This one?

COMMISSIONER MCALLISTER: Yeah, that one right there.

MR. ACHTELIK: That's just --

COMMISSIONER MCALLISTER: So you've got 2012 and 2013 there with, you know, 30 percent Fuel Cell Vehicles, and I'm wondering what the metric is there on the -- is that just numbers of cars? Or what is that?

MR. ACHTELIK: These are numbers of cars and it

is reflective of the ratio of Fuel Cells versus Battery Electrics. In the near term, because of a combination of credits and costs, you know, the more the automobile manufacturers put in fuel cells --

COMMISSIONER MCALLISTER: Okay.

MR. ACHTELIK: -- and then right now all the cost of the Battery Electrics are lower compared to the Fuel Cell, so more of them are producing numbers. And as the ratio changes between cost and -- because the Zero Emission Vehicle Regulation, we talk about it in terms of number of vehicles, it's actually in terms of credits, of emissions reductions. So as that value changes, it encourages production of one over another. So the changes are due to that.

COMMISSIONER MCALLISTER: Okay. So, but this is -- the 2012, 30 percent, that's a requirement?

MR. ACHTELIK: That's just an actual ratio, it's not a requirement, it's an actual ratio of how manufacturers complied. They could have complied with only BEVs, or they could have complied with only Fuel Cell Electric Vehicles.

COMMISSIONER MCALLISTER: Okay, so 30 percent of the ZEV fleet is actually Fuel Cell Vehicles right now?

MR. ACHTELIK: In 2012, yeah. So there were -- so if we said -- in terms of the credits, yeah.

COMMISSIONER MCALLISTER: Oh, okay, okay. I gotcha. I'll ask our Transportation staff to sort of pick that one apart for me.

MR. ACHTELIK: Okay.

COMMISSIONER MCALLISTER: So, thanks very much. Is there any -- Commissioner Florio, any questions?

MS. KOROSEC: Questions from anyone in the room? All right, we do have one question that's online, it's from Spencer Richley. Spencer, your line is open. Spencer, are you there?

MR. RICHLEY: Hello?

MS. KOROSEC: We can't hear you very well. Spencer, can you speak louder or closer to the phone? We can't hear you. All right, I think we're unable to get Mr. Richley, so if you can email us your question, we'll make sure to pass that along.

Next, we have Ryan Eggers.

MR. EGGERS: Good afternoon, Commissioners. My name is Ryan Eggers. I'm an Energy Commission Specialist within the Transportation Energy Office, and I'm here to present the Preliminary Refiner Acquisition Cost Cases in order to support the 2013 IEPR.

My presentation is planning on hitting on two specific topics, first being what are some of the current and historic trends in long-term crude oil

pricing; second, I will move into what are going to be the actual preliminary cases for refiner acquisition costs for crude oil.

So why do we care about crude oil prices so much? Well, first they form a big part of what the final retail price of gasoline is going to be. And for many Americans, gasoline still forms a fairly non-substitutable portion of people's travel needs here in the United States.

What you're seeing here with the green bars is the percent of income that on average Americans spend on gasoline, from 1983 to 2011. The red bar is what the average of expenditures on gasoline as a portion of income has been for the entire time period, which is roughly 2.4 percent. And what we're seeing here is, for the most part, is what one would expect, is as gasoline prices rise and fall, the amount of money that needs to be spent on gasoline in order to meet those basic travel needs also rises and falls.

In the early 1983 era, we were up to as much as four percent of total GDP was spent on gasoline, and as we moved into the '90s, as gasoline prices fell, we got to as low as roughly 1.5 percent of GDP. Finally, as we moved into 2000 and into 2008, with the increase in gasoline prices, also the expenditures on gasoline also

rose. But what is interesting as part of this particular graph is, even though gasoline prices rose to levels that, you know, are as high as we've ever seen here in the United States, the amount of income that Americans were spending on gasoline still did not reach to the same levels that it was in the early 1980's, and there's a couple of reasons for this, the first being obviously the increased CAFE standards, which has helped improve fleet fuel economy for not only California, but for the nation as a whole; also with some of the financial difficulties that started in 2008 for our economy, we have seen an increase in the unemployment rate, which has the unfortunate effect of decreasing average VMT as less people need to commute to work.

So what are some of the factors in crude oil prices? Well, the first being world supply and demand fundamentals, this is the classic Econ story of where more supply relative to a certain demand level tends to decrease prices. Also, as there's more demand relative to a certain supply level, that tends to increase prices or put an upward pressure on prices.

Since this is a world traded commodity, exchange rates also influence this dynamic with the weakening of the dollar, worsening the purchasing power of that dollar, thus more dollars are needed in order to buy

that particular barrel of oil. Conversely, as the dollar becomes stronger, less dollars are needed in order to purchase that particular barrel of oil.

Rising production costs also influences the final price of crude oil since, you know, crude oil is a finite commodity, as it becomes more difficult in order to produce crude oil, production costs tend to rise, and thus those production costs need to be passed on in some way, shape, or form because crude oil companies are in the business to make money. They're not going to take a loss on any of this.

Economic growth is also an influence on crude oil prices, normally by stimulating demand, thus putting an upward pressure on prices. Increased price speculation activities also influences this dynamic. While I can't tell you its exact influence or, you know, how much it adds to the price of crude oil, it is pretty safe to say that it does have some sort of positive monetary effect on the final price of crude oil.

Political unrest is the final thing I would like to point out. This often embodies itself as some sort of supply disruption within the crude oil production chain, thus lowering supply relative to demand and putting an upward pressure on prices.

So looking a little bit more closely at supply

and demand fundamentals within the world crude oil market, shown here in the green line is the price of crude oil at the world level. Also shown is the difference between world consumption and world production. These red bars are time periods where the actual consumption of crude oil is outpacing production. And as one would suspect, when we see a long run of these red bars, we also see a corresponding increase in prices. Also on the flip side, when we see production outpacing consumption, and these would be the black bars, we see a downward pressure on prices, and prices tending to fall during this time period. That being said, this is not the only influence on crude oil prices. And as you can see, for the most part, given a run of red bars it not always has the same sort of influence on crude oil prices. One of those other factors would be the value of the dollar shown here by the blue line, specifically here, this is the exchange rate between dollars and Euros. And as this blue line increases, the purchasing power of the dollar worsens, and thus you need more dollars in order to buy a particular barrel of oil.

Notice between 2000 and 2008 where we have one of our more prolonged acceleration of increases in crude oil prices, we have both a long run of red bars where

consumption is outpacing production, also a weakening of the dollar throughout that time period. And it's these two factors interacting with each other which is likely one of the reasons why crude oil prices rose so quickly during that particular time period.

So the end game for the Transportation Energy Office is actually to come up with transportation fuel prices for California specifically, which the crude oil price helps inform. But we do have some challenges in developing these fuel prices, the first obviously seen in the previous graphs, is just the general volatility of the crude oil market, for several reasons. One of them that tends to get on the news the most are unforeseen national political unrest. We also see some price volatility in local markets with unplanned refinery outages, sometimes adding to the premium for local retail gasoline or diesel.

The real elephant in the room for the Transportation Energy Office is we have no in-house integrated world energy or crude oil equilibrium model in order to project crude oil prices into the future, so we do need to come up with some solution to tackle that particular problem.

Also, as part of the changing transportation scene, we do make forecasts on alternative and renewable

fuels -- which my office manager got into -- but there is very limited data on many of these transportation fuels to no data at all.

Finally, we do have a very long term projection horizon and, as part of this 2013 IEPR, the Transportation Energy Office does plan on doing their forecasts out to 2050 to match some of the work that the ARB is doing with their 2050 Vision.

So in order to solve some of these problems, well, we in the Transportation Energy Office tend to use somebody else's crude oil projection in order to have some sort of basis to create local California specific transportation fuel price forecasts. And in order to do that, we take a look at all the world leaders, or the leading organizations in crude oil price forecasting, specifically the EIA, IEA, and there are several others, and we look at these different prices to kind of get a general trajectory of where the industry as a whole sees crude oil prices moving forward. Also as part of that, we look at their supply and demand forecasts because there does need to be some sort of relationship between local production of crude oil here in California, as well to the world market, in order to do our own in-house analysis of crude oil. We also do some linear trend analysis of historic refiner acquisition cost

data, in order to establish some general trends on where the trajectory of crude oil prices are heading, in order to get a reference of where we would expect crude oil prices to be in the near future, or even the long term.

And finally, we're always soliciting advice from workshop participants and anybody in the public regarding these crude oil price trajectories.

Now, I've always referred to the crude oil price in this presentation as the Refiner Acquisition Cost, which is kind of the averaging of all these different crude oil spot prices, and one of the reasons we do that is, instead of using a particular crude oil spot price, while all these crude oils tend to have their own orbit in relation to each other based on quality and sulfur content, sometimes local supply and demand sort of situations kind of knock them out of their orbit, and if we used one specific crude oil spot price, we could imbed some of those dynamics within our forecast. The most recent example of that would be the WTI, which in 2009 and 2010 happened to be a blend that was priced in between the Kern River price and the Brent price. But as more production came online, specifically in the Bakken in Canada, and was flooded into the Cushing, Oklahoma hub, this price was depressed. And if we use that particular benchmark in order to do our

forecasting, we would have that local supply and demand dynamic imbedded with our forecast. And since California doesn't use WTI, it would pollute our forecast moving forward. So instead, we basically use the average of all these crude oil spot prices that basically refiners take in, in order to do our crude oil projections.

So here they are. Here are the Preliminary 2013 IEPR Refiner Acquisition Cost Cases. The dotted lines would be the nominal price projections, with the solid lines being the inflation adjusted price projections. And what we see here in our high price/low consumption price case, we have prices increasing from roughly about $100 a barrel of oil up to $300 a barrel of oil by 2050.

In the reference case, which is the green solid line for inflation adjusted 2012 dollars, we have $100 barrel oil increasing to roughly $200 a barrel of oil in 2050. And in the low case, we have the $100 barrel of oil falling to roughly about $70.00 in 2012 dollars into 2050. All three of these lines come from the early release of the EIA, Annual Energy Outlook, and we plan on, when they finally develop their final high and low, to adopt those as our price cases for refiner acquisition costs, moving forward with our forecasting activities.

Now, the prices I just quoted are inflation adjusted prices, and these are not going to be the prices that are actually probably going to be quoted by the Press, or even seen at any given time point moving forward in the future; instead, inflation often infects this sort of dynamic. And using the same CPI or inflation estimate that the EIA used in its reference case, the actual nominal price for refiner acquisition cost in 2050, in our high price case, is going to be well above $800 a barrel of oil. In the reference case, it's going to be just under $600 a barrel, or roughly about $550, and while it was a static inflation adjusted price in the low price case, in nominal dollars that will be an increasing price up to above $200 a barrel of oil for crude oil.

Now, there's always certain production forecasts that need to be made when looking at crude oil pricing. Here is the EIA reference case projection for U.S. domestic crude oil, and one of the interesting things to see here is there is a very stark increase in local or domestic crude oil production that's being forecasted by the EIA. And this extra production is coming mainly in the form of tight oil, or shale plays, these particular production seems to be localized to both the Bakken and Eagle Ford supply areas, so this is a projection that

does not include any sort of California production from our shale plays here in California, this would be specifically from other locations. But it's really the world supply or production projection that really sort of matters when making these price projections because this is a world commodity. And as we see here, most of this extra production -- and we do see an increase in production within the reference case of the EIA -- most of this extra production is coming mainly from OPEC and from non-OECD countries like Russia, as part of picking up the slack for the decreasing OECD petroleum production.

As I mentioned earlier, we do take a look at other price projections by industry leaders, shown here by mainly the lines with the actual marks on them. I apologize for how cluttered this particular graph is, but basically what is demonstrated here is that all the other industry leaders for crude oil price projections are all roughly in the same sort of neighborhood of these three price projections, and they are mostly clumped around the reference line, with a few of them being below that. What is kind of interesting is the yellow line at the very very top, and the bottom line at the blue, which were the price projections from the EIA, from the last 2012 cycle, basically it looks like the

EIA has sort of narrowed their bands for high and low as far as price projections for the upcoming 2013 Annual Energy Outlook.

I'm also often asked by Commissioners to sort of give a review of how these price projections have fared over the last previous IEPR cycles, which is being displayed here. What you're seeing here is the 2009, 2011, and now the 2013 IEPR Refiner Acquisition Cost Cases. I do need to make a disclaimer for this particular graph. Both EIA and the Energy Commission only make annual price forecasts for crude oil; what you're seeing here is an attempt to turn those particular annual forecasts into a monthly forecast. And so what we're seeing here is the actual Refiner Acquisition Cost, which is the blue line with the triangles. In 2009, for the most part, the annual Refiner Acquisition Cost stayed on the high end of our particular band. When we smush these back into actual yearly averages, basically that actual average Refiner Acquisition Cost Case sort of falls a little bit within that band. But as you can see here, for the most part, it did follow the top of that band, then fell back down. Because of that, we did shift our band upward in the 2011 forecast, and for the most part it did stay within that particular band, accelerating when the Libyan

Government changed, and the Gaddafi Government fell, it sort of peaked out of that particular band, but then fell quickly back within that band.

What you're seeing by our 2013 forecast is basically taking all that information into account, we have a reference line that's roughly in the same place of where historic crude oil prices have been lately, with our high and low sort of encapsulating our high from our 2011 forecast, and our low from our 2009 forecast.

So, if there are any questions from the dais, I will take those first, and then I will open it up to the rest of the public.

COMMISSIONER MCALLISTER: Thanks for that. Yeah, I guess I'm wondering, well, first I'll just ask specific questions. So the tight oil, I mean, it seems like a pretty huge change that your graph at the top of page 6 here, yeah --

MR. EGGERS: Page 6 or page 11?

COMMISSIONER MCALLISTER: Sorry, I have two per page, so the top of page 6 which would be your 11.

MR. EGGERS: Okay.

COMMISSIONER MCALLISTER: So could you describe -- so clearly we're on sort of the tip of the iceberg here if we take this EIA forecast, this was in the EIA

forecast here on tight oil?

MR. EGGERS: Correct.

COMMISSIONER MCALLISTER: Okay, so could you describe where that's coming from and sort of what's driving it and, I mean, is it completely parallel to the shale gas? If you could just expand on that a little bit? I want to get a sense of how much, you know, what the characteristics of this are, but also sort of more importantly what the risk -- uncertainty associated with it actually might be.

MR. EGGERS: Well, I would probably say the uncertainty is very little on this particular forecast. This tight oil projection is mainly -- these totals are mainly coming from the Bakken and Eagle Ford areas, which is the North Dakota shale play, as well as the Texas shale play. And what you're seeing here are basically projections based off information that they're already getting from those actual plays. And starting in 2008, we've seen a very big jump in those particular plays as far as projection. And as they keep producing oil out of those particular locations, they get more and more information. And this sort of represents what the industry thinks they're going to get out of those two plays in the near future. Now, this is not really analogous with what we're seeing in natural gas because

we did see a very huge explosion in natural gas. This tight oil is coming strictly within their forecasts from those particular two locations, and so this isn't really an opening up of other locations; as I mentioned, there's no California shale oil extraction occurring in this particular reference forecast. And unfortunately I don't have any information on what's happening at the world scale at this particular resolution within the forecast at this time. So there could be increased tight oil production happening at the world level, it's just I don't have any data within their data tables to support that one way or another at this time.

COMMISSIONER MCALLISTER: In the U.S. production, is the price -- the likelihood that we know something about the price to have some relative idea, some good idea of what it's going to be going forward, you know, the production price I'm referring to, not the market price.

MR. EGGERS: Yeah, unfortunately as we look at the world stage, U.S. production is a very small proportion of this, less than 10 percent, and so it's really not influencing the world price to any certain great extent. That being said, it is depressing the WTI price because that is one of the reasons why that hub hah sort of a depressed price right now, because a lot

of that Bakken oil is going there and flooding that particular hub.

COMMISSIONER MCALLISTER: Okay, thanks very much. Let's go to questions in the room. Anybody in the audience, in the hearing room, that want to ask any questions?

COMMISSIONER MCALLISTER: Please.

MS. KOROSEC: All right, we've come to the end of our agenda. We have one final opportunity for anyone who would like to make any comments; however, since we didn't see any people leaping to their feet for this last bit, I imagine we've probably captured everybody, but just -- anybody who does want to make any final comments, or ask any final questions, now is your opportunity.

COMMISSIONER MCALLISTER: People are probably saving their juicy stuff for their written comments, I'm sure.

MS. KOROSEC: Yes, please.

COMMISSIONER MCALLISTER: But I really want to thank you, Suzanne, and your staff for putting this together, and the presenters for sure. This is really -- this is the foundational work and, to some extent, the experts are the ones who tend to be able to chime in intelligently to this conversation, and I think at some

level that's appropriate because it's complicated, and these models are specific models with their own lives and their own users who get it. But I think that doesn't make the conversation any less relevant for the public at large, and I want to just make sure that everybody who feels like they can make the time to put their knowledge on the table, to help the assumptions, and therefore the modeling get better, will be doing all of us Californians a world of good. So I want to just encourage those of you with any ideas or any feeling that it's not going the way you would do it if you were king for a day, let us know, like put it on the record, and we'll have that discussion, and potentially come out with a different approach. So I want to just encourage everybody to participate because that's what gives this process strength. And with that, I will ask Chair Weisenmiller and Commissioner Florio if they have any present comments.

CHAIRMAN WEISENMILLER: Again, I would like to thank everyone today for their participation. I think it's been a pretty fruitful conversation. Obviously, there's a lot of -- a lot goes into the Demand Forecast that cuts across various agencies, you know, we talked along the PUC side, the Air Board side, you know, and again the rate issue certainly connects -- we sort of

saw the calculator -- I was just trying to figure out, it's also seen Energy Division and DRA Rate Studies, I'm not quite sure they were based on the E3 Calculator, but again trying to have that conversation. So it's important we get this stuff right and it's important that we reach out to get the best information from all sides on it, and that we try to reflect not just an expected case, but low and high cases for all these things so we get some sense of what the inherent uncertainty is.

COMMISSIONER FLORIO: Well, it certainly gave me an increased appreciation of all the hard work that goes on here, and PUC will do all it can to contribute as appropriate.

COMMISSIONER MCALLISTER: And then thanks again to Commissioner Florio for making the trek out and joining us, and hopefully it's been fruitful, looking forward to doing similar events, the adequacy event next week in your house, and lots of back and forth in the future. It's really important work. So thank you for coming. Suzanne, do you want to sign us off? Do I need to close the proceedings here?

MS. KOROSEC: I think you can go ahead and close it, I just want to remind folks that written comments are due by the close of business on March 5th.

COMMISSIONER MCALLISTER: Okay, that will close out our workshop today, and thank you all for coming.

(Thereupon, the Workshop was adjourned at 3:50 p.m.)

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