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BEFORE THE

CALIFORNIA ENERGY COMMISSION

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	)	Docket No. 17-IEPR-03
	)	
2017 Integrated Energy Policy	)	
Report (2017 IEPR)	)	

IEPR COMMISSIONER WORKSHOP ON DATA INPUTS AND

ASSUMPTIONS FOR IEPR MODELING AND FORECASTING ACTIVITIES

CALIFORNIA ENERGY COMMISSION

FIRST FLOOR, ART ROSENFELD HEARING ROOM

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, FEBRUARY 22, 2017

10:00 A.M.

Reported By:
Kent Odell

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Commissioners

Robert B. Weisenmiller, Chair

Janea Scott, Commissioner

Andrew McAllister, Commissioner

CEC Staff Present

Heather Raitt, IEPR Program Manager

Chris Kavalec

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Also Present

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P R O C E E D I N G S

FEBRUARY 22, 2017 10:00 A.M.

MS. RAITT: Good morning and welcome to today's 2017 IEPR Commissioner Workshop on Data Inputs and Assumptions for the IEPR Modeling Forecasting Activities.

I'm Heather Raitt, the Program Manager. I'll quickly go over our housekeeping items. If there's an emergency and we need to evacuate the building, please follow staff to Roosevelt Park, which is across the street, diagonal to the building.

Today's workshop is being broadcast through our WebEx conferencing system. Parties should be aware that you are being recorded. We'll post the audio recording on the Energy Commission's website in a couple of days and a written transcript in about a month.

We will have an opportunity for public comment at the end of the day, and we'll be limiting comments to three minutes per speaker. For those of you who would like to make comment at the end of the day, please go ahead and fill out a blue card, and you can give it to the Public Adviser, who's currently sitting in the back of the room.

For WebEx participants, you can raise your hand using the raise-your-hand feature on WebEx, to let our

WebEx coordinator know that you'd like to make a comment during the public comment period. And at the appropriate time, we'll either relay your comment or open your line. For phone-in participants, we'll also take your comments at the very end.

Materials for this meeting are available on the website, and hardcopies are at the entrance to the hearing room.

Written comments are welcome and due on March 8th. And the notice for this meeting provides instructions for how to submit written comments.

And with that, I'll turn it over to the Commissioners.

CHAIR WEISENMILLER: Good morning. Thanks for your participation today. One of the key elements of the Energy Commission's work is the demand forecast. And, certainly, one of the things that certainly feeds into the demand forecast are the inputs and assumptions. So, as we kick off this IEPR, in a way this is one of the important workshops to lay the foundation for the end result. So, anyway, thanks for your help today.

COMMISSIONER SCOTT: Good morning. I'll just echo the comments that the Chair has made. And I will note, unfortunately, I can't be here in the afternoon, when we get to the transportation component. But one of the things that the Commission has done is we're working with the National Renewable Energy Lab to get some updated information for some of the vehicles, like electric vehicles, and places where the number of models have changed, the number of miles have changed, and things like that. And, so, that will be becoming incorporated into the transportation information that we have. And I just wanted to make sure to highlight that for folks. And I look forward to today's workshop.

MS. RAITT: All right, thank you. So, our first speaker is Chris Kavalec, from the Energy Commission.

MR. KAVALEC: Good morning. I am Chris Kavalec, from the Energy Assessments Division. And I have the wrong presentation up here. We don't seem to have my presentation up here.

Okay, this looks like the right presentation, here. I'm going to start off today talking, sort of in general, about the interconnected analysis that goes on in the Energy Assessments Division, through a discussion of what we're calling common cases, or common sets of assumptions that flow through the various modeling systems.

And I'm talking specifically about our electricity dispatch methodology, our NAMGAS model that projects natural gas prices. A methodology we use to project electricity rates, electricity rate scenarios. Our transportation energy forecast and, of course, our electricity and natural gas demand forecast.

So, these common case are meant to translate across the different analyses that we do. And that simplifies the transfer of output from one modeling system that becomes input for another. And that gives us a consistent basis for policy discussion within the various facets of energy issues that we cover in the Energy Analysis Division.

We, basically, go through what you could call iterations, through these various models and modeling systems. And we, typically, start off with the most recent demand forecast which, in this case, would be the recently adopted California Energy Demand Forecast Update, in 2016. And we sort of iterate through the electricity dispatch and NAMGAS models.

And then, through those outputs, we develop electricity rates, which are then transferred to our transportation energy demand, and electricity and natural gas demand forecasts.

And once we go through one iteration, we will have a preliminary California Energy Demand 2017 Demand Forecast, and this will become the starting point for a second iteration of these models, in the fall.

And, graphically, it looks something like this. On the left-hand side there, the most recent forecast fed into our electricity dispatch model, and then into the NAMGAS model. That provides output that's used to develop electricity rates. And the natural gas rates from NAMGAS, and the electricity rates, feed into both the transportation demand models and our electricity and natural gas demand models.

So, we go through one step here. We end up at the bottom right, with our preliminary demand forecast which, as I said, becomes the starting point for our second iteration.

So, these common cases have basic, raw assumptions, shared across the different models, including gross domestic and gross State products, population in households, outputs by different industrial grouping, used both for the transportation energy and electricity and natural gas demand forecasts.

Carbon prices, which are used to develop our electricity rates. And in a couple of the models we use heating degree days and cooling degree days.

And, then, along with that we have specific assumptions pertaining to each of the individual models, which we'll talk about more today, in later presentations.

So, our common cases, we define a mid-case, which is sort of a reasonably expected trajectory, given our most likely inputs. And, then, we have high and low cases around those to define a reasonable, as opposed to extreme range, around the mid-case.

I should mention that we also have a fourth common case, which is basically a tweak of the mid-case, that's meant to incorporate the impacts of doubling energy efficiency per SB 350.

And Angela Tanghetti will talk a little bit more about that, later today.

And I always like to mention that it's very difficult, or not impossible, to make these common cases completely internally consistent. For example, in a high demand case you would expect upward pressure on rates because of a growing economy. However, in the high case, we typically define that as high growth, with lower rates. However, a case like that would fit in between the range defined by the high and the low cases.

So, associated with these cases, we have specific Econ-Demo scenarios that we use, from our Econ-Demo vendors. In the low demand case, we propose to use Moody's lower long-term growth scenario, along with DOF population. Their population projections tend to be lower than those of Moody's and Global Insight, so we use that in the low demand case.

For our mid-demand case, we have the Moody's baseline scenario. And for the high demand case, we're having Moody's create a special scenario for us. In the past, we've used Global Insight's, what they call their optimistic scenario for the high demand case. But this scenario is not always consistent with the other two scenarios from Moody's.

So, for example, in this optimistic scenario, you may have much higher industrial growth, but lower commercial growth. So, we end up with a high demand case with much higher industrial energy projected, but lower commercial energy projected, so it's not always consistent across the sectors.

The trouble in the past, with the Moody's high case, is that it's typically been very close to the mid-case, so there's really no point in running that additional, that high scenario in that case.

So, what we asked Moody's to do was create a special high case that is significantly above the mid-case, for the key economic variables. And, unfortunately, I don't have any details on that today. They're still working on that. But that's what we propose to use for our preliminary forecast.

But I can talk about the mid-demand case a little bit. And here are some features of the mid-demand case. Unemployment rate's staying low, a sharp increase in housing starts within a couple of years. Oil prices remaining relatively flat, going up a little bit in the next ten years. And they assume that there's going to be a significant tax cut from the Trump Administration, coming in the next year or two.

First, a look at population in the mid-case, in the latest Moody's projection. A few weeks ago, we had a workshop on Econ-Demo. And the consensus among our Econ-Demo experts was that California's population growth was going to slow relative to previous projections for population. And the reason for that, or two reasons for that, first the higher cost of living, increases in cost of living in California. And the second was an assumed reduction in international migration due to the new Administration's policies.

So, the net effect of that is shown here. The red line shows the population in the mid-case, used in our recently completed forecast update. And the dark blue shows the new preliminary mid-case. And by 2027, we're down about a little over 300,000 souls in California from these to effects.

Lower population is also reflected in less personal income, as you see here. Again, comparing the mid-case from the forecast update versus our new preliminary forecast. In addition, there are two other effects that go into this difference that, again, we discussed at our Econ-Demo workshop a few weeks ago.

The first is tax cuts that would push growth upward. And the second is the sort of conventional view, or widely held view was that California is reaching a full employment economy and, therefore, there is less capacity for additional growth. Okay, once you reach full employment, you don’t have a lot of leeway to increase growth, compared to the cases, for example, when you’re coming out of a recession.

The net effect of these two, each working in opposite directions, one slowing growth, one increasing growth, is to reduce personal income by a little bit more than population, .75 percent in 2027. Personal income down by a little bit more, as a result of these two effects.

And manufacturing output, again comparing the two mid-cases, we have sort of the opposite effect. The net impact of a tax cut and a full employment economy actually brings up manufacturing output up. Although we are down compared to the previous forecast, we’re down less than the drop in population because the net effect of the tax cuts and the full employment economy is up, as it pushes it upward.

Finally, total employment, which is actually up slightly, compared to the 2016 forecast, by the end of the forecast period, because California is -- has reached almost full employment more quickly than had been projected in previous forecasts and, therefore, that's reflected here in more people employed by the end of the forecast period.

Also, you can see a flattening, starting in around 2019, of employment. As we discussed in our Econ-Demo workshop, most likely scenarios don't include a new recession, but they do include projections of a flattening of growth. And that's happening here, starting in 2019, and then we reach 2021 or 2022, and growth begins to increase, again.

Also, what we learned a few weeks ago was there's a lot of uncertainty, because we have a new Administration, and depending on what policy positions they take, we could see a significantly different set of Econ-Demo projections by the time we do our revised forecast in the fall.

For example, if trade policy leads us to so-called trade wars, or NAFTA is rescinded in some form, we could see a slowing of growth that might be reflected in a future Econ-Demo forecast.

So, that's my first presentation. Here, I give some information on submitting comments for the docket, for the 2017 IEPR Energy Demand Forecast, and you can see a link there.

So, to the Commissioners, questions or comments so far?

CHAIR WEISENMILLER: We're good so far. Thanks.

MR. KAVALEC: Okay. Okay, my next presentation is meant to give a status update on our ongoing development of an hourly load forecasting model. A little bit of background. WE typically do forecasts for peak, and for consumption, and for electricity, and natural gas sales at an annual level. However, long-term projections down to the hourly level are becoming more and more important.

We have this issue, because of renewables, of potentially pretty severe ramp-up period in the afternoon. So, we're interested in looking at not just the annual forecast, but the shape, the load profile of typical daily use.

And, as we saw in our 2016 Forecast Update, demand side factors, such as PV and electric vehicles, can potentially shift the peak hour. So, to really do an analysis of what that shift is going to be and when the new peak our is going to be, you really need to do an hourly load forecast.

So, our goal is to develop a model to project every hour of the year, going ten years out for a given geography. And to do that, we're planning to develop a sort of business-as-usual projections for total end-use hourly load. Meaning load that comes from generation of -- or, no matter where the generation comes from, whether it's behind-the-meter PV, or from utility sales. And, then, adjust these business-as-usual projections to account for increasing amounts of photovoltaics, and electric vehicles, along with AAEE, additional achievable energy efficiency, at the hourly level. Demand response and TOU pricing, which we'll hear a little bit more about in our next presentation.

So, once we make these adjustments, it's fairly simple to calculate where the peak is going to be, the maximum hour, which may or may not be a conventional peak hour, what we typically think of as peak, like 4:00 to 5:00, or 5:00 to 6:00, in the afternoon.

In our analysis for the 2016 forecast update, we saw peak hours shifting out to as late as 7:00 to 8:00 in the evening.

So, the first version of this model is going to rely on system-level hourly data, which we get from CAISO, at the -- what's called the TAC area level, transmission access charge level, for PG&&E, Southern California Edison, and SDG&E.

Later versions, once we go through our data rulemaking and, hopefully, begin to incorporate and receive metered data, we can do more disaggregate geographies, and we can also look at individual sectors. But for now, this 2017 forecast, we're doing these hourly forecasts at the system level.

More specifically, what we're doing is we're estimating the ratio of hourly load to an annual average load for each hour. That means 24 regression for each of the three TAC areas. And this is specified as a function of weather. We are currently including temperatures in various forms, along with the dew point as a proxy for humidity. And calendar effects, day of the week, weekend versus holiday, the month of the year, using all the hourly data we have accumulated so far, from the EMS data, which means 2006 through 2015.

The reason we're using a ratio, as I mentioned here, as opposed to an absolute magnitude, is that with ratios then you can plug in your annual average hourly load that comes from our traditional demand forecast, at an annual level. And through those annual forecasts, you're accounting for Econ-Demo and other effects that grow load. And, therefore, you don't have to -- these don't have to be incorporated directly into our hourly load model. That's why we're doing it that way.

So, the bottom part of this slide, this ratio specifies a function of weather variables, calendar effects. And, again, each of 24 hours, the whole year. And we have -- this should be, actually, ten years, not 1 through 7.

Now, so, once you have your regressions estimated and you're ready to roll with your forecast, you need to develop what you might call an average weather year for hourly temperatures. In our hourly load forecast, as in all of our traditional peak forecasts, we assume, because weather is so hard to predict, a "average weather year". Okay. With the exception that we make an adjustment for potential climate change impacts.

However, coming up with a single representative set of hourly temperatures, and using that for each forecast year, again as we saw with our peak shift analysis for the forecast update, you can have pretty abrupt year-to-year changes in projected hourly loads because of the calendar effects.

For example, your hottest temperature in one year might occur on a weekday, but that same hottest temperature the next year occurs on a weekend. So, then, your peak may move out to a different day or even a different month. So, you get these abrupt changes from year to year.

So, we believe that to do a reasonable hourly load forecast you need to do multiple simulations to develop a distribution. And we are doing that through what’s called a bootstrapping process, which is kind of a fancy way of taking random samples of hourly temperatures over the 15 years’ of temperature data that we have. But, of course, you want to retain the relationship between the months, and the weather, and hourly different patterns in a different day.

So, what we’re experimenting with, now, is a random sampling of 28, 30, or 31-day blocks over a 15-year period, depending on what month it is. And through that developing one simulation, and then going back and doing another random sample for developing another simulated year, and on, and on, and on.

So, through these end simulations you will have a median of all the results you’ve projected, and that becomes our peak, or one and two baseline peak forecast.

So, this next graph shows the importance and the impact of using multiple simulations, instead of one simulation, as we did in the 2016 Forecast Update.

The red line shows the results of one

simulation. Okay, one set of bootstrapped estimates for a future weather year. The dark blue line shows the results of using the medians of the peak for each year, using a hundred simulations. And you'll see how much smoother that is. You don't have quite as abrupt year-to-year changes. It becomes smoother.

However, there is a little bit of spikiness that remains in the dark blue curve, so that tells me that maybe the number of simulations need to go up to 500, or 1,000, and we're so we're still experimenting with that.

Further work for this modeling effort, as I mentioned we're investigating what the proper number of simulations should be to give us a reasonable forecast. We want to try and introduce other weather variables. For example, we can develop a heat index using temperatures and the dew point.

We're also thinking about what's called gradient boosting. This is a statistical analysis. It's a form of what is sometimes referred to as machine learning. And that's where you use your model, you project, and then you compare those to the actual. And, then, you use the errors, the difference between the two to educate the model and improve the model performance.

The load shape modifier impacts. As I mentioned, we're doing this at the system level, so we don't have a sector breakout. But you would expect that if residential consumption is going up compared to, say, industrial consumption, then your daily load shape might become peakier because residential use tends to become peakier, or tends to be peakier than the flatter, industrial loads.

So, incorporating this kind of impact we think is important, since we're going out ten years and that could have a significant impact. So, we're thinking about ways to incorporate changing sector distributions into this forecast.

Our plans are, as we're still working on this model, but to vet the model more fully with stakeholders at a DAWG meeting coming up next month, I believe March 17th.

So, anyway, that's where we are on the hourly load modeling.

CHAIR WEISENMILLER: Yeah, thanks, Chris.

A couple of questions. The first is, let's start with our two perennial issues, which might be more significant here. One is sort of the data questions, TAC, Edison questions. And the other one is the weather normalization issues.

So, where are we on resolving those and how -- as I said, my guess is they're probably more significant for the hourly forecast, than the annual numbers. But sort of, certainly, welcome your opinion on that.

MR. KAVALEC: Well, let's see. I'm not sure what you meant by the data issue?

CHAIR WEISENMILLER: There had been something between Edison and the ISO on the TAC questions.

MR. KAVALEC: Oh, okay. So, yeah, you're talking about the EMS data.

CHAIR WEISENMILLER: Yeah.

MR. KAVALEC: Yeah. So, for our weather normalization process, this time we're hoping that we have the utilities using the same data as we do. In the past, they used their own data, which is -- we're not sure exactly why they're different, but they're measured at different points. So, that's one of the reasons why we get different results when we do weather normalization.

So, as far as -- maybe the utilities can comment on that. But as far as I know, we should end up with the utilities all using EMS data this year.

CHAIR WEISENMILLER: Sure, come on up. Please identify yourself for the record, but just go ahead.

MS. HO: Hi. This is -- thank you, Chair, Commissioner Scott, and Commissioner McAllister. This is Delphine Ho from the California ISO.

So, I wanted to explain the difference in the data a little bit and how we're trying to resolve that issue for this coming year and, then, going forward.

So, there are slight differences in the data simply because of the way -- it's all coming out of the same system, but because of the way the data is presented in public sphere versus process, behind the scenes and then provided to the CEC via a subpoena, there are slight differences. And because there were rounding differences, because of the way that the information was aggregated.

So, what we're trying to take this year is taking the information, aggregate it up to the TAC level, so it should be apples-to-apples, the same data. We're going to provide that publicly, to stakeholders, on our website. So, LSEs, other IOUs can all have that information. And it should be the same between what the CEC receives and what's public.

For this year, we're going to have that in a spreadsheet format, going back three years, so everyone can do the forecasting analysis that's required. Moving forward, we'd like to have a more long-term solution so that the data coming out of OASIS, which is our public-facing interface, could provide that information as well.

For us, right now, that's a big kind of IT project undertaking, so that's going to require a little bit more time. But we wanted to provide the Excel spreadsheets so that folks can provide their forecasts as soon as possible for this coming year.

Okay, thank you.

CHAIR WEISENMILLER: Thank you.

MR. KAVALEC: As far as the methodology of weather normalization, that's another topic that we're going to discuss at the next DAWG meeting. That's an ongoing discussion. Because weather normalization is really kind of more of an art, than a precise science, as we've found out over the years.

And at least one of the utilities has some ideas on ways to improve the weather normalization process, so we're going to hear from them at the DAWG meeting. So, that's where we are on that, right now.

CHAIR WEISENMILLER: For the new model, what's, you know, the statistical goodness to fit? What sort of r squared or whatever are you coming out with?

MR. KAVALEC: For these different hourly regressions, it depends on the time of the day and how good of a fit you get. So, for the afternoon hours or close to peak hours you get a 95 percent r squared or above. And, then, in the off-peak hours, 2:00 in the morning, 3:00 in the morning, when temperature, weather plays less -- makes less of a difference, you're down to 75 percent, 70 percent r squared.

And once we develop this model, we'll provide all the statistics anybody could ever want, related to the model.

CHAIR WEISENMILLER: You also talked about how, as you're running the various sets to try to get some sort of smoothing, trying to get an understanding of when, obviously converged, or whatever the right thing would be, that when things are stable, at least. And is there any statistical measure of, you know, whether it's 100, or 500, or 1,000?

MR. KAVALEC: Not exactly. It's going to depend on the amount of data that you have, the goodness of fit that you have, and so on. But we're looking for two things, I think. The first is the smoothness of the results, like you just mentioned.

And the second thing is the normality of the distribution. So, how many simulations do we have to run before we can consider the distribution of the results to be "normal" and, therefore, be able to pick out not only a 1 in 2 from the median, but a 1 in 5, and a 1 in 10 peak hour. So, those are the two things we're looking for.

CHAIR WEISENMILLER: Yeah, those are tricky because I think, if you look at the underlying weather data, particularly correlations across space and time, the distributions are, you know -- I'm not quite sure they're very normal in nature.

MR. KAVALEC: Yeah, you may be right. It may end up that based on -- well, let me change my previous answer, slightly. We want to be able to run enough simulations so that whatever the underlying distribution results from all these runs becomes apparent, whether it's the normal, or r squared, or whatever other kind of distribution.

And, then, from that, again, you'd be able to start picking out 1 in X weather years, as opposed to just 1 in 2.

CHAIR WEISENMILLER: Yeah, you may want to talk to Jim McMann. He and I did some stuff in the 90s which basically looked at 50-year weather tapes across the west, and we were trying to find some correlations. And, eventually, threw up our hands and s imply ran, you know, the weather tapes through, in the various locations, to see what came out. That's the best way we could do the forecast.

But anyway, Jim probably has some recollection on that.

MR. KAVALEC: Yeah, and there's other work to check on that has been done in this area, that we haven't quite gotten to, yet, but --

COMMISSIONER MCALLISTER: So, I just wanted to build on that a little bit, and maybe ask it in a reverse way. So, how much will this new model be able to -- well, will you be running sensitivities on the new model, you know, based on things that maybe are outside the model? So, you know, how robust is the model? Are you going to test for robustness, you know, as uncertainties in climate proliferate? And, you know as, obviously, the future may look different from the past. And you're anticipating some of that. But, you know, what's the plan for running sensitivities in the model that are sort of, you know, outside the boundaries that we might typically consider? You know, just extreme events, and things like that, and develop some expectation of how accurate the model's going to be in those cases?

MR. KAVALEC: Yeah, so we have talked to Scripps, who provides our scenarios for climate change, about doing scenarios using hourly temperatures, and build in climate change impacts not only to our annual results, but to our hourly results.

Yeah, in terms of your general question, it's tricky. There's a lot of different impacts that you could test for, that could lead to skew your distribution, or lead to extreme results, some of what you might call extreme results.

All I can say, now, is that we're in the process of testing our model versus the historical data, and making it as good as we can be --

COMMISSIONER MCALLISTER: Yeah, okay.

MR. KAVALEC: -- before we attempt to start doing forecasts.

COMMISSIONER MCALLISTER: I mean, it's good to hear that the fits are better at the peaks. It makes sense. But that -- and that would be mostly the concern in extreme events is that you'd have some, you know, peak impacts. But you'd really want to pay attention to all the 24 -- all the 8760.

CHAIR WEISENMILLER: Yeah. I mean, certainly, looking at some of the peak load shift types of questions.

COMMISSIONER MCALLISTER: Yeah.

CHAIR WEISENMILLER: Having a great fit there is, certainly, really important.

COMMISSIONER MCALLISTER: Yeah.

MR. KAVALEC: Now, in looking at the historical data, we're very careful to look at how the model performs and during extreme weather events. And so far, using the typical regression and assuming a normal distribution, it gives a pretty good fit for even for the extreme events.

COMMISSIONER MCALLISTER: Okay, thanks.

CHAIR WEISENMILLER: Thanks, Chris.

MR. KAVALEC: Sure.

MS. RAITT: Thanks. Our next speaker is Lynn Marshall, from the Energy Commission Staff.

MS. MARSHALL: Okay. So, for this IEPR cycle we have several changes going on that affect how we need to prepare retail electric rate inputs. So, in the past cycles we simply prepared projects of annual revenue requirements, using the demand forecast to calculate an average annual rate for each of the sectors. And those were input into our sector energy models, residential, commercial, transportation. And they would account for the year-to-year effects on consumption of annual changes in retail electric rates.

For this cycle, now, we want to account for the transition of residential customers to default time-of-use rates, and also support the development of the hourly load forecast model, Chris was just discussing.

So, to do that, in addition to the annual average electric rate, we also need to calculate what we call revenue-neutral time-of-use rate that we can use in our -- in a model to calculate the price response of sector hourly loads, supporting our sector and climate zone forecasts. So, there will be several outputs from this.

So, we'll have hourly load impacts that reflect the incremental changes of the shift to time-of-use rates. We'll have modified single-family home, hourly load forecasts that are input into the self-generation model. And, then, we also want to have aggregated load impacts that can support modifications to the annual peak-in-energy tables that will continue to be needed for planning.

So, let me talk, first, about some of the updates for the annual retail electric rate forecast, and then I'll move back to the time-of-use discussion.

So, much of the data that will be used to update the final retail electric rates won't become available in time for the preliminary rates. The Demand Office needs those in March, so that will be a limited update.

But, primarily, we start with evaluating the revenue requirements data that the larger utilities will submit. On the non-procurement side, that includes looking at their projections of distribution, and transmission revenue requirements. And, then, in particular, we want to look at any pending rate cases and applications. For example, they have some new transportation, some electrification applications that would be incrementally.

There's also, importantly, on the distribution revenue side, the new general rate cases are starting to include requests to support distributed resources integration. So, for example, SCE's 2018 rate case has capital expenditure requests. On an annual basis, it's about 20 percent higher than kind of their baseline distribution cap. ex.

So, we'll see Office of Ratepayer Advocates, and other stakeholders' analysis of that, starting in April, so we can factor, probably, some scenarios around that in the revised rate forecast.

The Cal ISO will update their transmission access charge of revenue requirements forecast, usually in about May, so we'll be able to incorporate that.

And, then, finally, there was supposed to be a cost-to-capital proceeding this year, for the IOUs, but actually, ORA and the IOUs, in turn, have proposed a modification to the existing structure that would result in a slight reduction to their rate of return. So, that should be factored in. Unless we see large objections, I'll probably include that.

So, on the procurement side of revenue requirements, we start with the utilities' reported costs for the resources they already have under contract. Then, we calculate using the staff demand forecast for that utility, what's the incremental, conventional, and renewable need, and then we value those based on the staff market price forecast.

So, for renewables, we're using updated information from our cost-of-generation model analysis, which produces levelized costs for renewable resources.

On the wholesale energy market price, there's three key inputs. Natural gas HUD price, the heat rate, and the California carbon allowance. We don't have the new, NAMGAS scenarios, yet, so those will be included in time for the preliminary rates.

But looking at recent ISO data, it looks like the current implied market heat rate is lower than the assumption I used last time, which was 8,000 Btus per kilowatt hour. Then, looking at our QFER 1304 power plant database data, the statewide average heat rate over the last three years has been about 7,700. So, I'm going to use that as the heat rate input for prices. And I'll show that affects the price in a moment there.

So, okay, and then we have updated the carbon credit allowance price projections. And this is based on Air Resources Board proposed modifications to the Cap and Trade Program. So, there's a lot of uncertainty around where prices will actually end up, given the uncertainty around economic variation can lead to changes in emissions, how much emissions we'll get from complementary policies. There's actually a high probability that you end up either at the soft cap or the floor.

So, for the high-priced scenario, we assume the equilibrium price is at the allowance price containment reserve level, which is like a soft cap. And, then, the low price stays at the floor. And the mid-price is simply halfway through.

So, for each of these, since the credits are bankable over time, in equilibrium you'd expect the current price to be the present discounted value of the final equilibrium price. So, these are just fit using an exponential function to the final equilibrium price.

Okay, so putting all of that together, since I don't have HUD prices, I'm just using the current EIA short range forecast as a proxy to get a sense of what the starting point for the wholesale price will look like. So, combining the current -- the current gas prices than our previous mid-case assumption. They're a little closer to the low case. So, that lowers the starting point of the wholesale energy price by about $6 a megawatt hour, in 2017.

And then, the top two lines show the revised levelized cost used for pricing procurement of new renewables. So, in the updated cost of generation, the levelized cost analysis, the starting point is a lot lower. That's primarily reflecting how much the cost of solar has dropped. I think it was over $100 a megawatt hour in the last analysis, and now it's something like around $70. But reflecting the fact that wind and solar are more mature technologies, and we have tax credits expiring out in the 2021 time frame, we don't -- we're not projecting a big decline over the forecast horizon that we did previously.

Okay. And, then, finally, a methodology change I'm making. One of the key inputs in calculating the rates is how you allocate revenue requirements to the individual sectors. So, in the previous cycle, I just used the current energy -- the current sector allocations and held them constant over the forecast horizon.

So, to better support the impact of time-of-use rates, and support the hourly load forecast, I'm going to use the hourly prices from our PLEXES Dispatch Model to shape the annual price forecast, and then combined with hourly sector loads then you can allocate that to sectors more appropriately. That's consistent with the marginal cost allocation methodology that's used in the IOU rate cases.

And, actually, in those rate cases, now, the PUC is having the IOUs do that analysis more on a forward basis. It used to just be historic year. So, I have -- I can compare our results, for example, to their 2020 marginal cost analysis, and also use their capacity cost allocations, which are usually based on something like the loss of load probability analysis.

Okay. So, moving on to the time-of-use analysis. So, since the PUC decided, in 2015, that we were going to move towards a default of residential customers, to default time-of-use rate, there's a lot more activity than I can summarize on this one slide. But these are some of the key points for our purposes.

There's actually like two different working groups. One's been working on marketing, education and outreach to prepare customers for this transition. And, then, there's another group, the time-of-use pilot group, that has been guiding the development of a couple of pilot projects.

So, the first one we currently have ongoing pilot studies of opt-in rates. Each utility is testing three different rates. That began last summer and it's going to go through 2017. And the goal of that is to provide input to the IOUs and the CPUC that will guide the ultimate rollout in 2019.

Now, starting next year, we're going to have a default pilot, which is essentially an operational readiness test. They're going to transition a large group of customers at once. That will be, essentially, phase zero of the residential default transition, because those customers will stay on that default rate.

And, then, the plan is in 2019 we'll move towards a full rollout of all of those customers who aren't exempt. And there are certain categories of customers that will be exempt.

Now, simultaneously with all of that, all of the IOUs have rate cases that are evaluating how to change their time-of-use periods. So, for example, shifting the peak period from 2:00 to 6:00, to 4:00 to 8:00, or 5:00 to 9:00. There's some discussions around the precise, new periods. But those cases should get resolved and I think we can expect those new time periods to begin being implemented in 2018.

And, then, we also know that SMUD, in their last rate case, made a commitment to move toward residential time-of-use rate, as the standard rate. They don't have

-- there's not a specific rate case open, yet, but we're going to model them on the IOU timeline, for the time being. And, then, when we get more specific information, we'll incorporate that.

I'll say a little bit about what's happening on the nonresidential side. But, really, the big load impacts we want to account for are residential, so we're doing less here.

So, the IOUs have been transitioning the small, medium, commercial and ag customers for several years. For San Diego and PG&E, that's largely complete. I think they'll finish this year. So, a lot of those load impacts are already baked into the recorded hourly loads that go into the demand forecast. Edison has one last batch that should transition in 2018.

So, there may be some incremental effects there. We should see, in this year's load impact analyses reports, I think there will be some estimates of how the time-of-use period change could affect load. So, we're going to look at those load impact reports to identify any incremental adjustments we need to make on the nonresidential side.

So, back to our approach for modeling residential impacts. So, I'll talk a little bit about the overall methodology approach, and then get into the specific sources of assumptions.

So, one thing we know from the research on how residential customers respond to time-of-use rates, is it's very sensitive to local temperature conditions, and customer characteristics. Most importantly, the presence of air condition saturation. So, if we want a methodology that's going to support, ultimately support our forecasts, which are increasingly disaggregate, climate zone, now at an hourly time step, we want to account for variation in temperature across climate zones and across seasons.

So, a useful way to approach modeling that is the constant elasticity of substitution approach. So, it decomposes the price response into a peak/off-peak elasticity. So, that's your load shifting component. And, then, the daily price elasticity measures the reduction in total usage in response to a higher average seasonal rate.

An important part of doing this is that we need to make sure that this -- the rate is equivalent, revenue-neutral, to the annual average rate that is used in the sector models, because they're still running at an annual time step.

And, then, we can use -- Chris was discussing some of the work that like Scripps' doing. Climate change scenarios, we can use this type of approach to include temperature variation over time. And, then, for example, we have in our residential model air conditioning saturations increasing over time, so this formulation can account for that.

And, then, finally, steps estimate what then number of participating customers are, then those hourly, applying the elasticities, you can aggregate those hourly loads. But an important part of the load shape, and this will be related to some of the work going on in the future, to support the hourly load forecast, is appropriate and consistent adjustments to account for energy efficiency, electric vehicles, self-gen. So, it's ideally where we want to get to.

Then, we can apply those elasticities to the adjusted load to provide a modified load shape, that then can feed into the demand forecast models.

So, I'll discuss some of our options for these assumptions. For this IEPR cycle, in particular, there's no perfect options. And, so, all of these inputs and assumptions we're going to talk about at the March DAWG, Demand Access Working Group, meeting. And we really want to other stakeholders' inputs on how to approach this.

So, one very attractive candidate for this analysis, the Statewide Pricing Pilot. So, this encompassed all three IOUs, ran over 18th months. So, it includes two summers and one winter. And for non-summer months, this is really the only California analysis out there, in terms of what price response is in non-summer months.

One of the primary goals of this study was to support load impact forecasting. So, it did estimate the CES specifications. So, there are parameter estimates that adjust elasticities as a function of the hearing and cooling degree differential, peak/off-peak. And air conditioning saturation. So, that really fits in well to supporting the demand forecasting approach we use.

However, this was an opt-in study. And we know from, you know, research on residential price responsiveness, you have a big self-selection effect. And you know that the price responsiveness for an opt-in study will be much higher than if you defaulted customers.

So, this is a starting point. We’ve set up an initial model, using this framework, because it does cover all the months and it gives us a base to get the modeling infrastructure up and running, but it will need some adjustments.

So, that brings us to the next option. The SMUD Smart Pricing Options Pilot. And what's really interesting about this is they had both default and time-of-use options. And you can see in the table, there, that price responsiveness is significantly lower for the default customers.

So, the study authors characterize customers on a time-of-use rate in three categories. You've got always takers, people that are always signing for time-of-use rate because it works for them. You've got the complacents, who wouldn't sign up for it, but if you default them on, they'll stay on. And, then, you have people that are unaware, and they don't know they're on the rate, so they didn't get a price response. In the SMUD study, about one-third of customers were unaware. So, that those unawares and complacents, the combination of those really lowers the average customer response that you can expect to get.

But in aggregate, because you have more customers, you can still get larger load impacts. So, this study could be a basis for doing a statistical adjustment downward to account for the effect of unawares and complacents. However. it is only SMUD. SMUD's got, you know, the highest air conditioning saturations in the State.

So, one might hypothesize that in a climate zone with milder temperatures, that the sort of unaware and complacency discount could be even higher. And we just won't know that until there are some future studies done.

And, then, a third project of interest is the Opt-In Pilot that is currently going on. So, this project was really focused on issues like customer understanding, customer experience, hardship, and awareness to help the IOUs and the CPUC decide on how to design the default pilot rates in 2019. Estimating load impacts was not the primary goal. So, the sampling, the whole methodology is really not geared to estimate price elasticities.

But that said, there are load impacts that could provide an interesting basis for comparison. It is only opt-in, though. And they were legislatively restricted from doing a default at this time. But they did use a pay-to-play approach, where participants got a significant financial incentive to sign up. And the idea there is that helps to attract more complacents into the sample, and maybe offset some of the self-selection bias that you get in an opt-in study.

How effective, you know, how broadly representative the current sample is, we really won't know until we do an actual default of IOU customers and see that comparison.

But, like we said, there are summer load impacts available, now. In about September, we'll see a full year of load impacts. So, I think it could be a good reference. I can model those rates with those temperature -- with temperature data from that year, and give a sense of how the staff model results compare to what we're currently seeing in that pilot.

Okay, some of the other key rate design assumptions. The peak to off-peak rate differential, right, so it is it very mild, 1.3 to 1, or steeper, 2 to 1, 3 to 1? In the initial default rates, and in the default pilot, we can expect a pretty mild differential. Right? This is the -- the PUC called this TOU light. We're transitioning millions of customers to a new type of rate. We're not going to start off with a steep rate. You know, customer understanding and having a good customer experience is the first priority.

But we'll have some clarity on what the initial rates will look like. The IOUs have already proposed the default rates. The default pilot rates for 2018, they'll be working on, they'll be preparing advice letters in January, for the final default rates. And that's going to be informed by a lot of the research that’s ongoing, now. It’s just starting to come out, both pilot research, and then there’s a lot of qualitative research that’s going to inform those decisions.

But what we don’t know is after the first year or two of default will those differentials increase to become more time-based, or will they stay at that more subdued level, which you wouldn’t expect to see that much price response. So, we just won’t know.

On the number participating, I think both the SMUD pilot would indicate, and the current research, there’s not expected to be large amounts of opt-out, but that really doesn’t tell you about what percentage will continue to be unaware.

The IOUs are planning some statewide marketing and education plans to boost awareness and understanding of these changes, but that’s still a big uncertainty.

And, then, another variable that could factor into this is, as of 2020, the IOUs could be allowed to implement a fixed charge. And that could be used to reduce the -- that would reduce volumetric rates, and it could be used to maybe make a steeper tier differential.

So, with all of that, those are good variables to include in some scenarios, since we don’t know any of them. So, going back to how we usually do the retail electric rate scenarios, we have a high demand, low cost scenario, with low natural gas and carbon prices, and then we have a low demand and high rate scenarios.

So, one way we could overlay the time-of-use scenarios onto that is we have, in the low demand/high rate scenarios we assume higher engagement, greater price responsiveness, the PUC is comfortable with increasing those tier differentials because people understand what's going on and are responsive.

And, then, at the other end of the spectrum we have high demand, we have low rates, the tier differentials don't increase very much. You know, people are not engaged. And that would give you kind of the outer bounds of assumptions on the potential load impacts.

And, so, finally, we'll be working on this analysis more, to have some more detailed discussions in the March DAWG meeting. There are a lot of more information, and analysis, and decisions coming out from the PUC, so it will be worthwhile to revisit this in the October/September time frame, and maybe update the assumptions then.

So, any questions?

CHAIR WEISENMILLER: Yeah, let me start out with a couple. One, the thing that struck me so far is the wholesale rate discussion. And, in fact, I will docket a report, a presentation that was done by E3 at the Mid-C Seminar, basically on wholesale prices. And as we add more and more renewables, which we're going to do, they have a zero marginal cost. And, so, that is pushing down wholesale rates. You know, I've seen like a forecast that Bloomberg did that was just, you know, going straight down.

And, similarly, the E3 presentation that was done at Mid-C, again, has wholesale rates just going down. So, certainly, we'll docket the Mid-C presentation. Certainly encourage those doing analysis of it to file comments on wholesale rate projections.

But I know in talking to Bonneville, I mean Bonneville's revenue went down dramatically last year, like $20 or $30 million, because wholesale prices are going down. And, you know, and the good news is we're getting to average hydro this year, so it's going to be a real additional drop in wholesale prices.

MS. MARSHALL: Yeah.

CHAIR WEISENMILLER: So, one needs to work through what's going on, on wholesale prices. So, again, trying to -- again, I'll docket the one seminar. Certainly encourage people to give us input on what they anticipate on wholesale prices. But I think the general perception in the market is that as we add more renewables, just wholesale prices are going to keep going down.

MS. MARSHALL: Yeah, and that's a good point. There was a recent paper published by C.K. Wu, and some other people, analyzing the decremental effects of renewables on the market price. I haven't quite figure out how to translate that into this analysis, but that would be a good thing to do, to work on.

CHAIR WEISENMILLER: Yeah, it's interesting. Obviously, C.K. Wu was at the Energy Commission in the 70s. I haven't caught up with him in a while but, certainly, very smart.

So, the other question, just sort of just to flag for people was, as you said, going into the -- you know, we made a commitment to the PUC we were going to take into account pending rate changes, both time-of-use and fixed charges. And, certainly, need to true up what's going on there, in that area.

MS. MARSHALL: In which area?

CHAIR WEISENMILLER: In both -- well, the rate design in terms of -- you know, and we need to true up with them where they're going, but also the elasticity impacts. So, again, certainly very interested in any analysis any of the utilities are doing on these issues, or the PUC's doing, and get that into our record, too.

MS. MARSHALL: Yeah. So, the current research, specifically is not the -- like the current pathway is specifically not focused on estimating elasticities. And, actually, the PUC decision was very clear on that. The first order of business is to deal with customer education and understanding, and then we'll do the default rollout, and then we'll worry about, you know, load-estimating elasticities.

And, actually, when we do the pilot study, that will be the default pilot, and that will be a great opportunity to really estimate. But that's not a focus of research right now.

CHAIR WEISENMILLER: Well, yeah, I'm trying to figure out how are the utilities taking into account, in their -- does anyone have anything they can help us going forward? That I would just as soon find out now, as opposed to in December, have someone say, well, wait a minute, we have this methodology.

MS. MARSHALL: Sure. And I hope they'll come to the DAWG meeting and share that with us.

CHAIR WEISENMILLER: Right.

COMMISSIONER MCALLISTER: I guess, I mean it seems like there must -- I mean, I don't know if we have a PUC person here. But, I mean, if you're going to go through rate design, and you're also doing procurement, you probably need some idea of what the elasticity impacts of the new rate designs are going to be.

MS. MARSHALL: Actually, there's an interesting thing about the rate-making process. So, when they do like a generate case, and then they'll do the revenue, rate design, they actually don't assume. There is no assessment of price elasticity in rate cases.

So, as an economist, when I first started working on this issue, I went looking for the elasticity assumptions and I learned really quick there aren't any, because you'd never be done.

CHAIR WEISENMILLER: Well, it actually comes out more -- again, credit to this agency for decoupling in the 1980 GRC decision. That before that, the whole rate case games was always sales numbers. But with decoupling, they provide the right incentives for energy efficiency, which I'll credit Bill Marcus for that, in the GRC testimony.

MS. MARSHALL: Yeah.

CHAIR WEISENMILLER: That took that issue out of the rate cases, so people don't look at it. You're right, as an economist, obviously, it's going to occur.

But, again, I think part of it -- you know, the PUC's making these changes. They obviously, historically, always do rate limiters, so that they're rolling into the impacts of rate design changes more gradually. But, you know, we're doing long-term forecasts so, somehow, we have to figure out what it means.

And as I said, certainly remembering some of the prior years, that was the big issue for the PUC staff to make sure we were looking at, you know, the impacts of the rate design changes on mean.

MS. MARSHALL: Yeah.

COMMISSIONER MCALLISTER: But, I mean, I guess I'm -- there has been research on elasticity, and I believe in the time-of-use context, right?

MS. MARSHALL: Oh, yeah, so I just summarized --

COMMISSIONER MCALLISTER: It's a little dated but, yeah.

MS. MARSHALL: Yeah, right. So, there's a lot of studies there. And, actually, there's a lot of load impact studies. For example, their opt-in time-of-use rates, right.

COMMISSIONER MCALLISTER: Yeah.

MS. MARSHALL: So, there's a lot of good information in the load research studies.

COMMISSIONER MCALLISTER: Yeah.

MS. MARSHALL: But, again, it's opt-in. So, actually, in the recent Lawrence Berkeley National Lab Demand Response Potential Analysis, they modeled time-of-use rates by taking the Smart Pilot elasticities response for default customers, and then they used the PG&E Smart Rate Load Impact Analysis to statistically adjust for air conditioning. So, that may be an approach we can look at. There's still questions about, you know, PG&E versus SMUD customers.

So, there's a lot of research out there. I think I highlighted the key resources.

COMMISSIONER MCALLISTER: Yeah.

MS. MARSHALL: But I'm certainly open to any suggestions people have. We may have to, for this cycle, have to do some creative statistics.

CHAIR WEISENMILLER: Yeah, that's what I was leading to. I mean, you certainly tried to highlight.

MS. MARSHALL: Yeah.

CHAIR WEISENMILLER: I'm just trying to say if anyone else is all -- here's another approach to consider, I'd rather hear it now, than when we're getting into the adoption hearing.

MS. MARSHALL: Oh, sure. Yeah.

COMMISSIONER MCALLISTER: Yeah, the only other thing I would say is on slide 6, I mean definitely the -- let's see, what's the curve? The preliminary renewable price seems -- I mean, that's going to look pretty different by the time we get to the end of this, I would think. Because to reiterate what the Chair said, that renewables price there, the blue dots curve seems like it's headed downward and not flatter up.

MS. MARSHALL: Okay. Well, I'll pass that along to our cost of generation analysis team.

COMMISSIONER MCALLISTER: Yeah, okay. Great, thanks.

MS. MARSHALL: Okay.

CHAIR WEISENMILLER: Now, I know she said updates. So, the question is, you know, to double check the update at some point in the record.

MS. MARSHALL: Yeah, that's -- I think the idea for the cost of generation analysis is to put out a new report this year, but it's not complete. So, this is kind of fresh analysis. So, your input is certainly welcome.

COMMISSIONER SCOTT: You mentioned, kind of in the middle of your presentation, I think around slides 10 and 11, that one of the things -- you give a list of things that you will also be considering as you look at the modeling of the incremental TOU impacts. And one of those included electrification. And, so, I'm kind of echoing the Chair's call for information from people who may have it. As the utilities are starting to have the time-of-use rates for the electric vehicles and how people are using those, to the extent that they can get us information, I think that would be really helpful in this space, as well.

MS. MARSHALL: Yes, definitely. A lot of new proposals for time-of-use EV rates.

COMMISSIONER SCOTT: Absolutely.

MS. MARSHALL: So, yeah.

CHAIR WEISENMILLER: Well, thanks. Thanks for your work on this.

We're running a little bit ahead of schedule and we're going to do a shift in the order. Since Commissioner Scott's here in the morning, but the afternoon, we're going to jump to transportation next.

MS. RAITT: So, our next speaker is Aniss Bahreinian.

EXECUTIVE DIRECTOR BAEDEKER: Good morning, Commissioners, stakeholders. I'm here today, I'm Aniss Bahreinian, to discuss inputs and assumptions into transportation energy forecast. We don't have too many numbers to share with you, so we are going to limit the conversations to the conceptual discussion.

We are going to first have a brief discussion of the models. Then, we're going to move into inputs.

And, finally, the assumptions, the implicit and explicit assumptions in the models.

This is a reimagination of the model that we have presented in the past, except that we had way too many things in the previous one. And, so, this is an attempt to kind of declutter the previous version and make it a little bit simpler, with fewer boxes, and circles, so that people could see things better.

And, so, we have divided it into two diagrams. The first one is focused on the model and the second one has a greater focus on the inputs and the outputs.

With this one, as you can see, we are showing the models, the behavior models in oval green shapes. And, so, all the oval green shapes are showing the behavioral models. We have the personal vehicle choice, which is the light-duty vehicle demand model. Commercial vehicle choice, which is the commercial light-duty vehicle demand model. We have the freight energy demand, which is for heavy-duty trucks, et cetera. We have the aviation travel demand. We have the urban travel demand. And the intercity travel demand. The intercity stands for the long distance travel. And the urban travel stands for the short distance travel.

The personal vehicle choice model is the most disaggregate model in the system. It is the more complicated model. And as you know, as some of you know, it estimates consumer demand by about -- for about 362 different synthetic households, so it is highly disaggregated. And we are counting for households by different household types. By the size of the household, by the number of workers in the household. So, we don’t just throw a generic household there and ask how many vehicles they’re going to buy, and what type of vehicles they’re going to buy. We divide them into different sizes. How many workers they have? How many vehicles they currently own? And how much income they are making, different income categories.

And, therefore, we try to be a bit more precise than most other models on the market.

The result of that personal vehicle choice model, which is for the households, is the light-duty vehicle population for the household, which is then being fed into the personal travel demand models, which is the urban and intercity travel demand models.

The vehicle population out of that model is being used in conjunction with the VMT that comes out of these two travel demand models, along with the fuel economy that comes out of the personal vehicle choice model. All three of these are going to result into the fuel consumption that you would see in the end. So, fuel consumption is the output that we are all looking for. the end result of all of our activities is the fuel demand. That's what we are here to forecast.

But in the process, we have to also generate a forecast of vehicle population. So, we have to have both forecasts.

On the other side, we also have the commercial light-duty vehicle demand model, which is generating both the VMT for the commercial light-duty vehicles, as well as the vehicle population, and the MPG. And the result of that is going to be the fuel consumption for this segment of the market.

We are the only agency that separates these two market segments, as we have discussed in the past, and for a good reason. Even though commercial light-duty vehicles are about 13 percent of total commercial light-duty we do see, both in the survey and in the model, that they do have different behavior. And even as recently as the current survey, the 2016 survey, even the results of our PEV survey that we have conducted, it is early, the results are showing that even the charging behavior is different for the commercial PEV owners, versus residential PEV owners. So, you do see differences. And there are good reasons to segment these two markets and look at the differences in their behavior.

We also have two other models that are for light-duty vehicle models, and they are called Government Model and Rental Vehicles. They are for government and rental models. These two models also exhibit different behaviors. They are not behavioral models, but they have distinctly different behavior regarding the VMT.

For instance, rental vehicles have very high VMTs and they have very fast turnover. They're distinctly different from commercial models.

Government vehicles, they have turnover that is longer than the rental vehicles, and they have different VMT for different classes of vehicle. We do see distinct differences between the segments and there are good reasons to differentiate between them.

In addition to that, we have our freight energy demand that, unlike some of the other models that only focus on goods movement, we're also including surveys or economic activities. And the reason for -- these are things like concrete mixers, for instance. Our freight demand model also generates demand for refuse trucks, for concrete mixers, et cetera, et cetera, not just for movement of goods.

The aviation model, even though it is capable of forecasting demand for business versus personal travel, but because we don't have the data to support that, we have to make assumptions that the behavior is the same. But it is a model that can differentiate between those segments.

Off-road model, composed of off-road diesel and off-road transportation electrification. Those models, the ones that you see in the square, they are not behavioral models, they are spreadsheet models. So, they don't really respond to prices or income.

In this diagram, what we show is it has more of a focus on the inputs. The green oval shape here is all of the models, so it is all of the models that you saw in the other diagrams. But here, we have the focus on the inputs, and the inputs are composed of -- these are the key inputs. We have over 150 inputs. Obviously, we can't include every single one of them here, so we have put them into broad categories of inputs here.

And these are vehicle fleet, that mostly come from the DMV. They are crude oil price forecast, which is coming from the EIA. And, then, later we are using Gordon Schremp, now, for this forecast, the IEPR forecast is using it to translate into fuel prices, which is diesel and gasoline prices.

Lynn Marshall, as she discussed right now, she is generating electricity forecast. And our colleagues at the Natural Gas Unit, are generating forecasts for CNG, and LNG, and other forecasts.

Economic and demographic, and other inputs, we are using the same data that the rest of the Demand Analysis Office is using, and the rest of the Division is using. So, everything that Chris Kavalec talked about right now, we are using all of those data. With one exception, for the personal vehicle choice model, we also use what is called American Community Survey. Because we need that fine breakdown for the household types, we have to use American Community Survey to break down all of the households into the fine household types that we need for our vehicle demand forecast.

Vehicle attributes is another very, very important part of our inputs. This time around, we are working with Fuels and Transportation Division, and NREL, in order to generate the light-duty vehicle attribute forecast for our inputs.

And vehicle attributes, for those who don't know the term, it refers to vehicle prices, fuel economy, range, and other attributes of any vehicle. These are some of the very important inputs into our forecast. Fuel economy, obviously, is going to determine how much fuel a vehicle consumes, in addition to the VMT that a vehicle puts on every year.

On top of everything else, we have the 2016 California Vehicle Survey. And this is a crucial piece of our work here because it provides us with the updated data on consumer preferences for different vehicle types. This survey is still going on and, hopefully, it's going to be completed in about a month and a half. And, therefore, we are going to have the most recent, the most up to date data possible.

And this time around, as some of you may know, some of you have heard, we also included a PEV Owner Survey in the 2016 California Vehicle Survey. And the results are being analyzed as we speak here, and we are going to soon see the results.

But it provides us with all of the crucial elements of the consumer preferences, which is going to feed the model. We use the data to estimate consumer preferences for different types of vehicles, for different attributes of the vehicles, such as fuel economy, range, et cetera, and for different incentives that government offers for different types of vehicles, such as PEVs, such as FCVs, et cetera.

And the result of these inputs being fed into the model are the two major outputs that we have. And that is the vehicle -- the vehicle stock forecast, the vehicle population forecast, and the transportation energy demand. I should add here that we are forecasting transportation energy demand for all fuel types. This is another difference. We generate forecasts for gasoline, diesel, for hydrogen, for electricity, for E85, for propane, and I think I called them all. For all fuel types, if I missed anything.

So, what are the sources of our input data? Our forecast uses, has a run of only 150 inputs, and we are using multiple sources of input, both internal and external data sources. Some of the input data, such as vehicle attributes, we are using directly into the model. So, let's say we are working with NREL, we just get the data directly from them and we input it into our model.

Other input data, such as DMV, requires a lot of analysis, a lot of processes, and we have a staff that are dedicated to just this task. It takes a lot of work to use, to analyze that data. And, actually, there are other agencies that are using the result of our analysis. We constantly get requests from other agencies for analysis of DMV data, from other agencies and other divisions.

And some of our data is our -- so, we are the primary source. So, our data, such as the California Vehicle Survey, we are the primary source of data. And our data is currently, for instance, the 2013 survey is posted on NREL website, and for academics and for universities, for researchers to use. It is available on NREL website. And, along with California Household Travel Survey, the two surveys can be used to build integrated models, and everybody can access it. Of course, we don't put any of the identifying information on that website. But without that identifying information, all of the data is there for all the researchers and academics to use.

So, for our forecast, we always have to select a base year. And the selection of the base year is based on the limitations of the data, for the most part. Our DMV data, the latest year that we have, this year, is the 2015 year. And, so, 2015 is going to be our base year.

Selection of the base year is quite important because we use the base year data to do a couple of things. We use the base year data to calibrate the model and to pivot the model. So, it is quite important to get those numbers right. We use the actual data for that. So, as much actual data as we can get, we use for the base year, which is 2015, for the 2017 IEPR.

We have the total fuel consumption by fuel type. So, that means for every fuel type that you can imagine, gasoline, diesel, hydrogen, electricity, et cetera, we have to have a measure or an estimate of the total fuel consumption for this year, for 2015.

Our colleague, Gordon Schremp, for instance, gets a lot of the data from Board of Equalization. They make adjustments to it and they provide the data, for instance on gasoline and diesel consumption, after those adjustments. But what they provide for us is the total diesel gasoline consumption for the entire State.

It is our job, then, to break it down to different sectors. So, that breakdown, by itself, is going to be challenging to break it down by -- remember all those models that we had? We need to break it down by all of those different models.

We also have the total VMT and we are currently, we have been, and we have been working with CalTrans and ARB for a very long time. We have been trying to coordinate, and collaborate, and get our numbers as close to each other as we can get.

Our colleague, Gary Yowell, has been working on translating the fuel consumption that we are getting from VOE, and Gordon Schremp provides the adjusted fuel consumption numbers for him. We try to -- he will use that to translate that fuel consumption, using the fuel economy from the EPA, and then come up with that estimate of VMT.

Currently, our numbers are pretty close to what we have at ARB, with the inside. But we are in conversation with ARB, and with CalTrans, and we want to get those numbers closer together. And there is a meeting that is planned pretty soon, for a conversation with them to see what the sources of differences are, and if we can bring them together. Just as we have held long conversations with ARB on bringing our DMV data closer together. Even though both agencies are getting the same numbers form the DMV, depending on how you're counting the vehicle, we have differences in the total population of vehicles in the State of California.

And, again, we have been talking with each other to reduce the differences in the two agencies' estimate of the total vehicle population, and we have done so. We have reduced the differences. We haven't eliminated it, but we have reduced it and we are in more conversation to get closer and closer to each other.

So, Gary Yowell takes the fuel consumption, uses the EPA's fuel economy number, along with the total number of vehicles in the State of California, and then comes up with an estimate of VMT. And the method is close to what ARB is also using, and we are again going to have further meeting to come up with a number that gets even closer to each other.

So, getting that aggregate total annual VMT for the State of California is quite important for us. Again, it is going to be our challenge to then divide it between the short distance travel, long distance travel, for freight, that's our job to make that division. We have to make that distribution.

Then, we have to have a lot of data on travel activity and people's movement. We rely, we have been working with CalTrans on their Household Travel Survey. We are pretty familiar with that survey. And we have been using that survey, in addition to the National Transit database, to get a lot of data on people's movement, and number of trips, et cetera. So we, again, get data from multiple different sources, and try to resolve the differences, and come up with a good estimate of travel activity.

The same thing is true for goods movement. We use, again, multiple sources. And we, again, look to ARB for our -- to resolve some of these differences. For vehicle stock, again, I already talked about it, we work with ARB, and we also use National Transit database in order to compare the number of transit vehicles that they record. Compare that to our DMV number. So, we do a lot of different comparisons and analysis to come up with our best estimate of what these should be.

And on the aircrafts, we look at the data from Bureau of Transportation Statistics.

So, that is our base year. And we try to get as accurate, as precise as we can get, because it is important for our forecast. That is the jumping board for us. Then comes the forecast years, that is 2016 to 2030.

Then, we have our transportation energy prices. Gordon Schremp is going to follow my presentation. He is going to discuss how he will be forecasting gasoline and diesel. Lynn Marshall talked about electricity prices. And in the afternoon session, they will be talking about natural gas prices.

Income and employment, again, and Chris Kavalec talked about, actually, all of these three, income and employment, economic activity, right, business sector, and price deflator. All of these come from the same sources that Chris Kavalec discussed right now.

Class-specific attributes for LDV and HDV, these we are working with NREL, again, Fuels and Transportation Unit. And we want to emphasize here, also, that these are class averages. That’s important.

These are not vehicle attributes by make and model. It is not the price of Tesla, or the price of Leaf, or the price of Volt. It is the price of the classes that each of these vehicles are representing. These are class average prices. Because the model is entirely based on classes. So, the make and model doesn't matter. What matters to us is each class of vehicle.

Population in the household is by household types. And, then, when it comes to population we are using, again, the same data sources that the rest of the Demand Analysis Office uses. When it comes to household types, we are using American Community Survey. We have already computed the analysis of the 2015 American Community Survey and we know exactly how many households we have in each of those categories. We know how many households we have that are 1-person households, 2-person households, 3-person households. How many of them are only one vehicle, two vehicles, three vehicles, et cetera, et cetera. So, all of that already has been entered.

But when we are growing them into the future, so we know all of the base year data, but when we grow them into the future, we grow them in a way that is consistent with the population growth in the State of California, as used by Chris Kavalec and Moody.

With all of these, they are going to form our demand cases. For, also, demand case, we have selected 2030 forecast horizon. It's a little bit, two years, I guess, above everybody else. One of the reasons is because it covers a number of milestones, policy milestones. The ZEV Mandate 2025, SB 350 2030. We have the different fuel economy, fuel efficiency standards in 2027, 2018, et cetera. So, 2030 forecast horizon covers a number of milestones, policy milestones.

We have three common demand cases. These are defined the same as the rest of the Energy Assessment Division, using the same economic and demographic inputs as the rest of the Demand Analysis Office uses. And, then, we use the same energy, transportation energy prices. And when it comes to electricity and natural gas, we use the same prices that the rest of the division uses. When it comes to gasoline/diesel, of course, we are using the prices that we are projecting.

So, these are the proposed common demand cases. We have the high energy demand case. This is composed of, or course, the high income and high population, which is a component of the high energy demand. But in order for demand to be high, we have to have the low prices. So, we have low electricity, natural gas, and hydrogen prices. We have, also, low petroleum-based fuel prices.

When it comes to mid-energy demand, we have everything that is the mid-case. And when it comes to the low energy demand case, we have the opposite of the high. We have the low income and the high energy prices. So, all energy prices are high, and income and population are low.

This is a departure from what we did in 2015 and 2013. As you may recall in 2013 and 2015 IEPRs we had -- in 2013 we had five demand cases. And in 2015, we had six demand cases. And three of those in 2015 were transportation-specific demand cases, where we kind of searched the place of alternative fuels and petroleum-based fuel prices.

This time around I think there was an interest in reducing the number of cases. And in order to make it consistent with everything else in the rest of the division, then we settled with the common cases. And we deleted the transportation-specific cases.

The key assumptions, when it comes to regulations, is that all current Federal, State regulations are in place. For original equipment manufacturers, including zero emission vehicles mandate, CAFE, et cetera.

All Federal and State regulations in place for transportation fuel suppliers. All infrastructure will be in place to meet consumer demand. And, then, all State and Federal ZEV incentives will remain at their current level.

Notice, please, that the first three bullets relate to suppliers.

I'm going to take you back to the first diagram that I showed here, and I want you to pay attention to the first -- the title of this slide. It says, "Diagram of Transportation Energy Demand Models." That's important. Because what we have here, our forecast, is purely a demand forecast. We don't have any behavioral supply model. This is not an equilibrium model. We do not have any supply model. And that's important when we are considering regulations.

So, going back to this slide -- sorry, I think I went too far. Going back to this slide, notice the first three bullets are all supply related. So, you would ask, well, what are you doing with this? In the past, what we have done, we have asked our attribute contractors to observe these regulations because there's no way our demand cases can observe them. We are forecasting demand. We can't observe them.

So, we have asked our attribute contractors to make sure that they are projecting attributes that are consistent with the ZEV Mandate. How did they do that? Typically, their mode of comply is -- typically, the way they did that, they lowered the prices, they lowered the ZEV prices in order to comply with the ZEV Mandate. They did either, they did one or both of them, they lowered the price of the ZEV vehicles in order to ensure that ZEV Mandate is met, and/or -- it's not or -- and they also increased the number of makes and models. So, they offered more makes and models in the market in order to provide incentive for the consumers to buy them.

So, those were the mechanisms through which they have been trying to comply with the ZEV Mandate. That's how they did it.

We didn't do anything in that regard. What we did do was the last bullet that you see here, all State and Federal ZEV incentives remain at their current levels. So, what we did was to follow the ZEV incentives. We kept all of the ZEV incentives in place. So, if there was a rebate of $2,500 for a PEV, we kept it in place for the entire forecast. If there was a Federal tax credit of $7,500, we kept that in place. Because those are demand-related incentives. We cannot account for the supply-related regulations. But we can accommodate demand-related incentives.

So, that is how. For those of you who are asking or wondering how did we do this? That's how it was done. When it comes to LCFS, Cap and Trade carbon prices, as you have seen in some of the presentations, fuel prices are adjusting for those.

When it comes to light-duty vehicles, our key assumption here, this time, is that we are going to keep consumer preferences unchanged over the forecast period. So, obviously, we are getting the latest set of consumer preferences, with the new survey, and these are end results. But we are showing that consumers have increased their preferences for EVs. We are going to keep them the same over the forecast period.

Now, that doesn't mean that this is actually what is going to happen. We think that consumer preferences for ZEV are going to increase. The question is what is the best way of projecting that increase? And we haven't come up with a good way of projecting it. Otherwise, we know people are going to become more accepting of the ZEV vehicles, and consumer preferences will increase, as our survey is showing that it has increases. Or, at least, I shouldn't say that, I should say preliminary results. By the time we have preliminary workshop, we can who you exactly how much it has increased.

We are also making the assumption that vehicle manufacturers and suppliers will meet consumer demand. So, this is a byproduct, and that’s important, this is a byproduct of not having a supply curve. If we do not have a supply model, the implicit assumption is that, well, whatever you want producers are going to produce, and supply that in the market. So, we don’t worry that if you want a million vehicles, a million ZEV, a million of this vehicle, or a million of that vehicle, we don’t worry that the producers are not going to produce it. We are making the assumption that producers are producing them.

So, this is an implicit assumption that comes from the fact that we do not have a vehicle supply model. But the vehicle manufacturers and suppliers will meet the consumer demand. Manufacturers will offer vehicles with fuel economy, as described in the projected attributes.

So, remember that there are attribute contractors, in this case NREL, is going to provide us with a set of attribute projections, including vehicle prices. So, our assumption is that vehicle manufacturers are going to supply the market with vehicles at those prices.

When it comes to medium- and heavy-duty trucks, we are saying that firms will choose trucks with a payback period of two to four years. Most of the models are looking at payback periods of two to four years.

We are also saying that intermodal freight, compared to total freight, is going to have a fixed proportion and it will remain constant. Intermodal freight is something like, for instance, in a truck is moving a container from, say, port to the terminal. And we are saying, we are making the assumption, because we don't have an intermodal freight in the freight model, we are making the assumption that this is going to remain in a fixed proportion to total freight.

Vehicle manufacturers will offer trucks with fuel economy described in EPA NHTSA, Phase 2 Fuel Economy, and MPG. So, again, because our attribute contractor is going to implement that Phase 2, then we are making the assumption that vehicle manufacturers will offer vehicles with those MPGs, and with those fuel economies.

When it comes to price, our key assumptions are that fuel and vehicle price scenarios cover the range of plausible outcomes. So, we have a range of it. We have the high, low, and mid, and we are saying that the high and the low are covering the range of plausible outcomes. Which is true, really, for all of our forecasts, for everything that we do in our division.

Inflation rate, we typically only have one inflation rate for all three scenarios. And, so, we're assuming that inflation rate is the same for all scenarios, regardless of the economic growth fact.

When it comes to fuels, again we are making the assumption that fuel suppliers will meet consumer demand in all scenarios through domestic production and/or input. Again, it goes back to that same diagram. If we do not have a fuel supply model, which we don't, implicit assumption is that regardless of how much fuel we want, it will be supplied in the market, whether we are importing it from other places, or whether we are producing it domestically.

In this one, what I'm saying is that fuel choice is endogenous between vehicle technologies, but exogenous with, we think, the same vehicle technology, and that can be a little bit tricky.

So, what does this mean? It means, for instance, that when it comes to vehicle prices, when it comes to electricity prices, say, I'm giving you one example. Electricity prices and gasoline prices, they are going to influence your choice between a PHEV and a gasoline vehicle. So, these are choice of two vehicle technologies.

So, if the electricity prices are higher, then versus gasoline prices, then you could pick one technology versus the other. That determines your choice.

However, because we do not have a fuel choice model within the same technology, when you're saying that it doesn't influence, that difference, the price of fuel differential between electricity and gasoline does not influence your choice, when you are going to the pump are you going to fill that up with gasoline or are you going to put electricity in the car?

So, that's an assumption we make. How do we deal with it? We are exogenously forcing that choice. We are using the EPA's rules, or we are in the conversation with the ARB and we come up with a ratio of what portion of the VMT will be EVMT and what portion will be gasoline. So, it is not endogenous to the model, the result of the fuel price differentials. It is being imposed on the model. That's what this means.

Transportation energy demand forecast only accounts for energy used from tank to wheel, to power the movement. So, we are only, really, accounting for motor power. Anything that happens before or after, we don't account for that.

Key assumptions when it comes to transportation electrification. Again, we are looking only at on-road motive power. That means we are looking at all those vehicles that have -- that are driving on public roads in California. That is those vehicles that have -- that are registered for on-road operation by DMV. Those are the ones that we are looking at.

But I also want to kind of differentiate, because a lot of the off-road discussions also include rail as off-road. We don’t do that. We are also including rail and high speed rail in our transportation energy demand. I just want to make that one clear.

Stationary and off-road use of electricity in transportation sector and off-road use of electricity in commercial and industrial sector is accounted for by TCU model. So, what is TCU? TCU is transportation, communication and utility. That is one of the models in the Demand Analysis Office that accounts for electricity consumption in that sector. The sector that accounts for transportation, communication and utility. Mostly, ideally, that model should account for stationary use of electricity, say, in transportation.

One example would be, for instance, let’s say you’re talking about Greyhound Bus Station. They have to turn on the lights, right? They have to turn on the light. So, TCU accounts for electricity use for lighting Greyhound Bus Station, while we are accounting for diesel used for the buses in moving from point A to point B. That's what we are doing. So, TCU accounts for electricity use.

However, when we were completing our off-road transportation electrification in the last IEPR, most of what was in that contract, off-road transportation electrification, was accounted for in the TCU. We did not account for most of those.

Any questions?

COMMISSIONER SCOTT: I do have questions, but I'll wait until you're finished.

MS. BAHREINIAN: Okay. All right. So, we had, as most of you may remember, in 2015 we had a contract with Aspen, and Marshall Miller of UC Davis. And he completed a project for us, or one of our forecasts that was called "Off-Road Transportation Electrification." It includes things like forklift, for instance. Forklift is used in industrial and commercial sector. Forklift, really, is moving things, right? I mean, technically, theoretically, it's something that moves, right? And I just said, multi-power, right? So, really, we should be accounting for it, right?

But it was accounted for in the TCU. That's what I'm saying, that off-road use of electricity in commercial and industrial sector is accounted for by TCU. This is what we did last time.

And we have to improve upon this distinction between the TCU and transportation energy forecast, which is done by our unit.

Key assumptions, when it comes to travel, is that changes in sector economic activity change travel demand for goods movement. So, for instance, if there is an increase in agricultural production, there's going to be an increase in demand for goods movement in that sector. That's what it means.

Land use changes do not change travel demand. This is an assumption. Why is this an assumption? Because we don't have a model that accounts for it. It doesn't mean that that is correct, it is just because we don't have a model that accounts for the impact of land use changes on travel demand.

When it comes to commercial light-duty vehicle, what we do is we use VMT per vehicle. Part of our distinction between commercial and household vehicle choice is that our commercial light-duty vehicles -- the commercial sector has higher VMT. And that is one of the good things that we do, we segment the markets. We have higher VMT. And, but the way we account for it is we have VMT per vehicle.

But we are really forecasting that into the future, how this VMT per vehicle is going to change over the forecast period. So, we keep it constant over the forecast period. So, as the number of vehicles grow over the forecast period, total VMT grows. But VMT per vehicle remains the same.

Again, key assumptions for economic, income distribution does not change with changes in income. Notice that in all of our economic forecasts, we are growing income, but we haven't said anything about income distribution. And I, for one, have not seen any forecasts of how the income distribution is going to change in the future. I haven't seen any, actually.

Income scenarios cover the range of plausible outcomes over the forecast period. That's, again, an assumption that is true for all of the forecasts in our division.

Growth rates over the range of plausible outcomes cover the range of plausible outcomes over the forecast period. So, growth rate refers to things like agricultural sector, how it is growing in different scenarios. We are covering the range of plausible outcomes industrial sector, commercial sector, financial sector, et cetera, et cetera.

Key assumptions explicit. Air passengers behave the same whether they travel for business or personal reasons. Air travel remains the same whether they travel for business or personal reasons. Again, I said that the model is capable of distinguishing between these, but we don't have the data that can distinguish between business travel and personal travel. And for that reason, because we are using the same coefficients, then we are not distinguishing. Because we don't have the data to support it, we have to use just one set of coefficients.

We also are saying that there is a single growth path for aviation fuel economy. We get that from EIA, and there's only one path. And, so, we have to make the assumption that there's only growth path.

And, finally, we are saying that light-duty vehicles do not migrate between commercial and personal market segments. So, we said that we have the household market segment, residential market segment, and we have the commercial market segment, and we also said we have government and rental. We have all these market segmentations. But these are separate models, lining alongside each other. These models do not talk to each other. There's no bridge between them.

We all know, all of us know that cars move from one segment to another segment. I, myself, I bought a car from a fleet. It was a one-year-old car, and it had 89,000 miles on it. So that car, the car I bought, moved from the commercial sector to me, in the residential sector.

But our models, currently, do not allow for that. It is our plan, sometime in the future, to create a bridge model to move the cars from one segment to another segment but, currently, we don't have that. And that's why we say the assumption, if we don't have that model, then we are implicitly making the assumptions that LDVs do not migrate between commercial and personal market segments, while we know that it actually happens.

Even in 2009, when we were looking at the DMV data, when the prices were high, we did notice in the DMV data that some of the cars, some of the hybrid cars actually moved from the residential sector, where the flow was actually reverse. Commercial sector was actually buying some hybrid vehicles from the residential sector because fuel economy was better and prices were higher in that time. So, moves actually had reverse -- some of the cars had reverse flow. We saw that. It is happening. It's just that the models currently do not allow for that migration. That's all.

Questions, comments?

COMMISSIONER SCOTT: I do have some questions and comments for you. Kind of back near the beginning, I will note that I'm really happy that you are working with the Fuels and Transportation Department, and also with NREL on the vehicle attributes. That's really important. The vehicle attributes that we had are quite out of date. They don't reflect the different types of models that we have available in the plug-in vehicle, plug-in hybrid electric, and hydrogen, and the ranges, the chargers, the infrastructure, all of that. So, having that updated will really help provide some robustness to that component.

I also want to note that I was glad to hear you mention, when you were talking about the key inputs and sources, that we are collaborating closely with the Air Resources Board and with CalTrans. I think it's important for the State to kind of speak with one voice and not have a bunch of different numbers out there, where we spend half of our time explaining why our numbers are different. And, then, sort of the message we're trying to send with those numbers is lost because you've spent so much time trying to explain why one number is different than the other. So, I appreciate you all working together with CalTrans, with the Air Resources Board to make sure that we have a robust set of numbers.

And I had some questions for you. On your slide 10, we talked about key assumptions of regulations. And you mentioned that that's supply side, and so that it's not really included in our demand, transportation energy demand. And I'm not quite sure I understand that. I'm not sure how we put together a demand forecast that doesn't account for any of the regulations in the space that we are looking at demand.

MS. BAHREINIAN: Okay. So, this is the slide 10, right?

COMMISSIONER SCOTT: Yes, and you mentioned that the first three bullets were related to supply.

MS. BAHREINIAN: Yes.

COMMISSIONER SCOTT: And, therefore, cannot be accounted for in the demand model that we have. So, what is the demand model reflecting, if it's not reflecting the regulations that go with the sector that we're looking at?

MS. BAHREINIAN: And because notice that the ZEV Regulation, for instance, is a regulation that is designed for manufacturers. It is there to motivate the manufacturers to offer these vehicles in the market. They are required to offer them in the market and sell them.

Our consumers are motivated by the price of these vehicles. And, so, the only thing that can motivate our consumers to purchase them is the price. And as I said, the ZEV doesn't directly apply to the consumers, the ZEV Regulation doesn't directly apply to the consumers. Rather, what they need to do. What we do is work with NREL, prior to that with Sierra Research, or prior to that with KGD (phonetic). What our direction to our attribute contractors was, one of our directions was that you need to project these attributes in a way to ensure that ZEV Mandate is met.

So, it was their job to make sure that the ZEV Mandate is met. How do they do that? They do that by lowering the prices. So, they project, for instance, EV prices. And whether that is, for instance, comparable to gasoline vehicle prices.

And we take their prices, input it into the model, and then see how the consumers respond, that they are buying the same number of -- the vehicles that would be required by the ZEV Mandate.

COMMISSIONER SCOTT: So, to follow up on that, most of the regulations that we account for in the Energy Demand Forecast are not regulations directed at consumers. So, when we're talking about anything on the appliance efficiency side, on the building efficiency side, on solar, on any of those other things that we're accounting for, those are not regulations aimed at consumers. But they're still able to be counted in the demand forecast in those sectors. So, I'm not really understanding why we can't do that here. I mean, I heard what you said. But, you know, if we say we're have a million solar homes program, we assume that there's a million solar homes out there. Not that we have to talk somebody into buying a solar home, is my understanding.

And I might be getting that wrong, but I can't -- I'm not understanding how we can have a transportation energy demand forecast that doesn't include the regulations that go along with transportation energy demand.

MS. BAHREINIAN: Because our demand, in our models, in our demand, consumers have to respond to the prices. They don't know anything about the ZEV Mandate. And, for instance, when we had -- even when we had our focus groups for the survey, we asked all of these questions. And a lot of our respondents don't even know about the regulations.

Some of them, I should tell you, when we gave them some of the handouts about the different types of vehicles, they did not even know that these vehicles existed.

COMMISSIONER SCOTT: But you don't have to know that the vehicles are there for the regulation to be either driving down the fuel economy standard, to be providing additional models that people can buy. You don't need to know that an energy efficiency regulation is there, when you go and pick a computer, or when you're designing a building, but those things are still incorporated in. So, I'm trying to understand. And, you know, maybe we can take the discussion offline.

But I really don't understand how we can have a robust and useful transportation energy demand forecast that doesn't account for the things that are driving some of that.

The reason you put a CAFE standard in place is not to talk a consumer, necessarily, into buying a car that gets better miles per gallon, because overall we're trying to reduce petroleum consumption, right? So, to not count that in where we're going with petroleum consumption I'm not -- that's the disconnect I'm having here.

MS. BAHREINIAN: Well, the consumer, when they are going to the dealership and they want to make a purchase, they look at the vehicle price, they look at the fuel economy, and then they also look at the gasoline prices.

One, for instance -- first of all, you know, the manufacturers have to offer vehicles with good fuel economy because CAFE standard requires them, right? They have to offer those vehicles.

But it is the consumer's choice to buy that vehicle or not. It is their choice to purchase that or not. And if you look at, for instance, when the prices of gasoline fell in 2014 and after, you could see a distinct increase in the number of larger vehicles. You could see that in the vehicles that are sold on the market.

Why? Because when they see that gasoline prices are lower, they have the tendency to move towards the larger vehicle. This is how the consumers are making their choices.

CHAIR WEISENMILLER: Yeah, but aren't the auto manufacturers adjusting the sales price to basically comply with government regulations?

MS. BAHREINIAN: Yes, they do that.

CHAIR WEISENMILLER: Okay. So, I mean, so we don't -- so, I guess what I'm saying, we don't necessarily have to get into the question of, you know, should GM provide a $9,000 -- you know, lower the cost of the Volt by $9,000 to encourage sales. It's going to happen because of the regulations.

MS. BAHREINIAN: Yes. But that is why the attribute contractor is going to account for the fact that GM is lowering their price.

CHAIR WEISENMILLER: But I mean, again, GM has to comply, so they will adjust the prices of their models to comply with the regulations using the CAFE, or the California regulations.

MS. BAHREINIAN: Yes. But it is GM that is doing that.

CHAIR WEISENMILLER: Yeah.

MS. BAHREINIAN: And it is those lower prices that are going to -- so, from our demand side, consumer is responding to that lower price. They're not responding to ZEV. They don't even know what ZEV Mandate is. They are responding to the lower price of the vehicle and the performance of the vehicle.

Just consider, for instance, the Tesla. Consumers are falling head over heels for that.

CHAIR WEISENMILLER: Right.

MS. BAHREINIAN: Just consider, you know, the fact that 400,000 people just went and bought the Model 3. They put their money. They like the vehicle performance, they like the price, and they go for it. They don't even think about whether this is a regulated -- this is part of the regulation or not. They look at the price, they look at the performance, and then they spend their money.

COMMISSIONER MCALLISTER: Well, I guess let's just elaborate on that Tesla example. I mean, so we have a goal. I think there are two ways to look at it. One is we're going to achieve the goal and the market is going to figure out how to do that. So, GM is going to figure out how to sell those cars. Part of it is price, but part of it is many other hedonic, you know, characteristics, right.

So, I mean, how are you distinguishing, say, between a Tesla, that is an expensive car with, you know, a high price and, you know, fuel economy that's not that different from other electric vehicles, and another electric vehicle that's cheaper? I mean, are you segmenting customers and saying, oh, there's a certain customer segment that wants this more expensive car? I mean, low price -- it is about a huge variety of attributes. And it seems like a little bit of, at least in the near term, just sort of out of thin air to sort of say we understand, you know, the breadth of consumer influence is a little bit beside the point. When we're really just trying to -- we're trying to map a path that gets us to our goal. Which we have a solid regulatory environment that I think will ensure that the market takes that seriously and achieves it.

So, it seems like it's a little bit cart-before-the-horse here, in terms of, you know, you're trying to sort of going to make the case that consumers really are going to do this, when we actually know that it's going to happen.

MR. BAHREINIAN: In the case of the Tesla, it all follows on the attribute contractor and how they are projecting the prices.

If you recall, in 2015, one of the things that we did, which was new, actually, was we used the DMV data and we came up with what we called the sales-weighted transaction price.

So, we don't look at the individual vehicle prices because, remember, our models are class average. They are not make and model based. They are based on class average. So, we looked at the class of Tesla, whether the class, let's say, is large car of EVs, with that range, with those characteristics, and then we looked at all of those cares in that class that are offered, how many people purchased them. And we looked at the prices of those cars and we took an average, a sales-weighted average price.

Now, whether the attribute contractor is also going to use that sales-weighted average price or not, that's something that we can discuss with them. But we are using that because you have the luxury class, and then you have the regular vehicles. We don't distinguish between luxury and non-luxury. We have an average price for the class of vehicle, with different attributes.

So, whatever is decided, it is reflected in those prices. And the price projections that our attribute contractor, based on their knowledge of what is going to come to the market in the future, they are going to give us those price projections. Then, we use those price projections, we provide that to our consumers and we tell them, okay, these are the prices. This is the range of the vehicles. We have the fuel economies. This is the price of gasoline. This is the price of electricity. This is how much it is going to cost you per mile to drive this. Because we all know that EVs are more efficient than gasoline vehicles, and the cost per mile is a lot lower than gasoline vehicles.

We give our consumers all of that information and then we let them make their choices. And that's all that they need to know.

Now, ZEV, to the extent that it is going to influence the manufacturers to lower their prices, it is going to be reflected in the attributes that NREL is going to provide us with.

COMMISSIONER SCOTT: Well, maybe you can help me with an analogy here. And I don't know a good, necessarily, one to pick. But maybe it's a new appliance standard. And, to me, what I feel like what you're saying is let's say we put in a new appliance standard that all refrigerators across California have to meet. But we aren't going to count that in our demand on electricity because people may or may not decide to buy the refrigerator. And, so, we've got to make a bunch of different assumptions about what the price of that refrigerator has to be in order to figure out how to calculate that into the electricity demand forecast.

But, really, the point of that regulation is to drive down the overall amount of electricity that's being demanded at a certain point in time, and so that's how you would roll that kind of a regulation into it. So, to me, it sounds like on that one you -- we wouldn't count those because we can't guarantee that people would buy the refrigerators, and so that would put it into this same kind of supply assumption, and not into the demand forecast.

And, so, if you're missing key regulations or key -- yeah, regulations that are designed to drive not one person, but an entire industry a direction, or designed to reduce petroleum consumption, or designed to reduce electricity consumption, but we’re not going to count that because it really depends on what the consumer wants to do at the end of the day. That’s the part I’m having a hard time making the connection with.

MS. BAHREINIAN: Okay, so let me ask another question. Does the standard, the refrigerator standard, does it require the stores in California not to carry anything but that standard?

COMMISSIONER SCOTT: It might or it might not, I’m just --

MS. BAHREINIAN: Because that would make the difference. If it is --

COMMISSIONER SCOTT: So, on the CAFE side, all of the cards have to meet a CAFE standard.

MS. BAHREINIAN: Exactly.

COMMISSIONER SCOTT: Now, and so, but what I hear you saying is if a person won’t buy that car, then we can’t count the CAFE standard into the transportation energy demand. I just -- I don’t think I’m articulating this very well, but I’m having a hard time making this connection.

MR. KAVALEC: Maybe I can add something.

COMMISSIONER MCALLISTER: The analogy with the standard, I mean, yeah, it's a -- if you don't meet the standard, you can't even sell -- you know, you can't sell that device. So, it's a little -- I mean, it's a good analogy, but it's not quite exactly complete.

But I guess I'm just kind of trying to understand why we, at the Commission, who -- I mean, so, it seems like in these averaging assumptions and sort of, you know, the choosing of certain characteristics, a limited quantity of certain characteristics that cars have, that fully captures consumer behavior. I think it's kind of folly.

I mean, people are going to -- the market is incredibly rich. People buy things for a variety of reasons. They buy cars -- you know, the larger piece is important for people, the prestige piece, the color. I mean, people buy cards for all sorts of different reasons. And I think that, you know, the manufacturers and the sellers of cars know that way better than we ever will.

So, you know, I feel like it's good to have an appreciation of that in the model, but that's more of the tail, not the dog. Right, the information from the marketplace about what is and what we assume will, or what we need to happen to sort of get to where we need to go, that's kind of what we need to model. And, then, as we go, we can understand, you know, in a deeper way what customers -- why customers are making those decisions. But that's more of an after-the-fact thing, instead of a driving.

Like, I think if we've purporting to predict consumer behavior and make that drive our forecast, then that seems like a little cart before the horse to me.

MR. KAVALEC: So, years ago, I worked in transportation and this issue came up a lot. Ideally, what you would want to do is go through an iteration process between supply and demand. So, to the best of your ability, you project what vehicle attributes are going to be, then you make the forecast based on how consumers are going to respond to those attributes.

The result may be, for example, that CAFE is not met. Then you go to the next iteration. We're not meeting the CAFE. We're going to have to add -- we, the suppliers, are going to have to start adding more fuel-efficient technology, or change the models that we offer, change the prices among the different models. And then you go for the next round.

The same with ZEV. You're only getting, you know, 2 percent penetration. Well, you're going to have to add more ZEV models or you're going to have to lower the prices.

And we did this to a limited extent in the past, but we always ran out of time. So, basically, the problem we're dealing with here is we have a partial equilibrium and we don't have -- we haven't had the time, at least in the past, to go through and do a full equilibrium model with supply and demand.

COMMISSIONER MCALLISTER: Yeah, so I agree with that. I totally agree with you, this iterative process helps us learn, it helps the market adapt. We can come up with policy recommendations. Okay, we're not meeting our goal. We're going to have to do the same thing with the doubling of efficiency and any other -- you know, any other big policies that we have.

Yeah, so I agree with that. I guess, I feel like I've heard some version of this for a couple of years running.

CHAIR WEISENMILLER: What I would say is that, you know, we're talking about the transportation demand forecast. You know, we're not necessarily looking at the supply side of the equation. And that's true, you know, like when you're doing the residential forecast, we're not trying to figure out whether the four-wheel take industry can build up -- match the demands for what we've built in. You know, it's hard-wired in. It's not an overall system. It's the demand forecast. And, so far, it's been a pretty good assumption the Chinese are going to build every PV plant module we need, if not more.

And, similarly, we're assuming something on residential housing. You know, that that's going to occur. And, you know, in some areas of the State it's not occurring in terms of actually getting it built. But, again, it's a demand model that we do to simplify life. That, you know, that if you really tried to do an all-encompassing model, we'd probably never get to a conclusion on an IEPR cycle.

So, I guess what I'm saying, on the transportation part some of what -- you know, you've flagged a number of simplifications. I don't mean defensive. Again, you're doing a demand forecast model, yeah. You know, and the more we can simplify things, get it done, and then start flagging some of the second order effects, you know, as we go forward, that would be good.

MR. SCHREMP: And Commissioner --

CHAIR WEISENMILLER: And keep the boundary.

MR. SCHREMP: Oh, I'm sorry.

CHAIR WEISENMILLER: Yeah. Keep the boundary, you know, tight.

MR. SCHREMP: And, Commissioner Scott, this

Gordon Schremp, Energy Commission staff.

Asking about -- as Aniss pointed out, there are supply aspects on this slide. And she says this is not a supply model. It doesn't mean that those regulations are ignored or they don't exist. If we were doing, as Chris suggested, a supply assessment, we'd look at availability of certain transportation fuels, say, to meet the Low-Carbon Fuel Standard.

And, then, in that kind of analysis one might observe, later on in the regulation, some specific fuels might be not as available, scarcity, links to higher prices, or higher market clearing credit prices, as an example in that kind of supply analysis.

But, no, that's not the work that we're doing that feeds into the demand model. Although, we recognize the regulations are in place, we have different fuel specifications. So, how we capture that is on the price side. We look at higher prices in California for specific fuels because we have regulations that differ from most of the United States and maybe most of the neighboring states.

So, in a way, we are -- we know what the regulations are on the fuel side, and we try to capture that in more expensive fuels over time, if we think that's appropriate, because of the nature of the regulation.

COMMISSIONER SCOTT: Okay. I don't have any other questions right now.

CHAIR WEISENMILLER: So, good. Let's take a break until 1:15. Thanks.

(Off the record at 12:23 p.m.)

(On the record at 1:51 p.m.)

CHAIR WEISENMILLER: Okay, let's restart.

(Pause.)

MS. RAITT: Okay. We're improvising here. Thank you for your patience. Gordon Schremp is going to go ahead and start his presentation, and we'll be changing the slides for him. Thank you, Gordon.

MR. SCHREMP: Good afternoon. Remember, good things comes and go too late, so now you're going to find out why you had to wait so long for my presentation.

So, the next slide, please? Are we on, or not?

Apologies. Can you hear me, now? There we go.

So, the next slide, please. So, Aniss, before lunch, was talking about the modeling effort for the Demand Forecasting Unit. And one of those inputs certainly was transportation prices. But before I get to sort of the end part, the purpose of why we're doing that, which Aniss explained a little bit, I want to sort of step back and look at the historical information because that can be instructive as to where we've been, what happens with the prices to provide some context to the whole -- you know, the whole forecasting genre of looking forward in prices, either in a low, mid, or high point.

The next slide, please. So, this slide is historical prices going for both gasoline and diesel fuel in California, all the way back to 1995. And I think a couple of important takeaways from this slide is, certainly when we do a forecast, do we forecast a 50-percent drop in prices over a period of less than a year? The answer, of course, is no.

Do we forecast significant deviations down and back up, oscillations like that for transportation fuel prices? No, we don't do that.

Although, we've had those in California and certainly in other parts of the nation, they do occur. So, that's just to let people know that, yeah, there will be a price forecast, but it's not precisely predicting what prices are going to be one year to the next. There is a great deal of uncertainty.

This is what was covered in a previous IEPR workshop, when we did a panel, and we were talking -- we had some experts talking about price projections, crude oil prices, and they were talking about a significant amount of uncertainty associated with crude forecasting values because of what goes on in the marketplace, the players, both OPEC, non-OPEC, geopolitical events, and the significant changes in demand.

So, just wanted to let you be aware, let that sink in that what happens historically can be significant deviations from what we forecast, even in the very near term.

The next slide, please. So, gasoline prices in California are more expensive and there are reasons for this. Certainly, taxes, which will fluctuate over time relative to that of the U.S. average do change. That difference is now down to 7 cents. It’s been as high as 17 and 19 cents in the past. Although, taxation policy in California, and the formula used to calculate tax on gasoline was changed in 2010. And, as a consequence, there’s been a degradation in the amount of tax applied to gasoline and that of diesel fuel.

So, we also have a higher production cost for gasoline and that’s because we use a unique formulation in California. It’s California reformulated gasoline, and an assessment made by the Air Resources Board, it costs between 10 and 15 cents a gallon more than conventional gasoline.

There are some newer fees, environmental fees, and these are significant to include because they're meaningful in magnitude. They're not just a penny or two, or fractions of a penny. So, these are fuels under the CAP, and these is part of the AB 32 program for Cap and Trade that apply to transportation fuels, and Low Carbon Fuel Standard, or LCFS.

So, both of those have a monetary quantification. The Oil Price Information Service is one entity that endeavors to calculate what they think those transaction prices are, and the value, and the size of the credit. So, currently, in 2017, that's about 14 cents per gallon.

So, the last is refinery issues. And we certainly have our share of those in California. 2015 was a very significant year for refinery problems. And, as a consequence, we saw much elevated prices in California. So, you put those all together and that's why California prices are more expensive.

Now, going forward, as Aniss was talking about, assumptions you'll keep levelized going forward. And I think for us it's wherever the taxes are in place, now, we assume that differential will be maintained. We know, historically, that hasn't happened. But there are changing taxation regulations in other states. There are changing, even, proposals this year, in California, to increase the excise tax for both gas and diesel that have not yet been adopted. I'm not saying that they will be, but that would change that differential we have in our assumption.

So, the next slide, please. This just shows a bar graph and what the relative difference in California retail was versus U.S. average. And, then, you see the huge jump in 2015. That was a consequence of refinery, significant refinery problems that lasted, for ExxonMobil almost 17 months. So, that rolled into 2016, which is why the differential was so high in that year relative up through, say, 2009 through 2014. And, now, it's back down to a -- I wouldn't say a more normal level, about 47 cents. Right, I think this morning, it was about 62 cents a gallon. So, there's some other refinery problems going on right now. So, this just shows that we do pay more for our gasoline here. It is more expensive.

And this is something that feeds into the model into the amount of, you know, the cost of the fuel for a vehicle that's of a specific fuel type or, if one's looking at different types of technologies, with different types of fuel prices.

The next slide, please. Diesel, it's the same thing. There's the same number of factors that we look at for why the fuel is more expensive. Taxation, it's about the same as gasoline differential. The production cost is not as great for California's own reformulated diesel fuel regulation. And we also have fuels under the CAP, and the Low Carbon Fuel Standard, which account for about 17 cents a gallon.

And refinery issues, I know for gasoline it's 10 cents or more. We see, in the diesel market, the diesel market's a little bit different in California. Meaning we're a bit more excess production capacity for diesel fuel. And, so, refinery problems we've seen over the years haven't impacted diesel prices as significantly as they have gasoline.

So, the next slide, please. In a similar fashion, we're showing the various annual average differentials to the U.S. diesel price, and that's on-road, ultralow sulfur diesel, more recently. And you'll note that in 2015 there was a jump up, but that's really not associated with the refinery problems we had in that year. It's more associated with fuels under the CAP coming into the program January of 2015, and that sort of pass through of that fee, if you will, is nearly equivalent to the average differential increase between 204 and 2015.

The next slide, please. The next slide. So, looking at -- I want to look at crude oil and some other factors. The biggest push to move retail gasoline, diesel, and jet fuel is crude oil. Crude oil is the driver. That's the way it is in California, that's the way it is in the United States, other parts of the country. This is the feedstock that's used to make these fuels and it's the same feedstock used to make all these fuels in refineries.

So, you can just look at this chart and you see, wow, red line goes up, green line goes up. The red line goes down, the green line goes down. But similar, they follow each other very closely. That's because this is the dominant factor determining what the retail price of gasoline will be.

The next slide, please. Diesel, different color blue, the same result. It will follow crude oil very closely, mostly. But looking at these lines moving around a little bit, it's hard to discern what -- is this difference the same one year to the next? One period to the next?

Let's go take a look at the next slide. And one more, please. Thank you. So, this is the difference between the retail price and subtracting crude oil. So, if the difference was always the same, this would be a flat line. Of which, clearly, it is not. It moves all over the place. It's been rising a little bit later in the period, and that's when we had some significant refinery problems. So, there are other reasons the retail prices fluctuate, other than the change in price of crude oil.

The next slide, please. Here are a laundry list of reasons, and there is an arrow next to a specific bullet to indicate what impact these kind of factors have on prices. Moving them up, both directions, if they're in the middle of the pack there, or down below. You could have a change in the futures contract prices, for example they fluctuate all the time. And they have a direct impact on retail prices in California because of the nature of how wholesale, DTW prices are set relative to futures contract prices. So, that's an example that that moves around.

So, these kinds of factors are what will change prices significantly over very short periods of time. However, as Aniss was explaining before lunch, we have to make assumptions about what will the taxes be going forward over the forecast period. What will be some of the other environmental factors? Will they change? Will they become more difficult to achieve, you know, compliance in a specific regulation? Therefore, will the fee go up? And, so, that's our assumptions for the Low Carbon Fuel Standard, the fees will escalate over time, as the regulation becomes more challenging.

And, so, in a preliminary release of the information, we'll show you what our assumptions are for how high those fees might be, as one example.

The next slide, please. This is just an example of you can have a situation where crude oil prices in the first red oval are -- the crude oil is the yellow squares in the bottom. They're dropping a little bit, flat and then dropping. And you're seeing that the wholesale prices, the lines in the middle, are rising rapidly.

So, this is an example where crude oil is not really pushing up those prices of wholesale and then on to retail, this is really a result of refinery problems, significant ones. As well as the transition to a -- from one winter recipe to summer recipe gasoline that always increases prices because the cost of making gasoline goes up for that transition.

And similar, the second oval, red, in the middle of the chart you see crude oil prices are falling and here we have prices rising significantly in the whole sale market, and to a lesser extent in the retail market. So, crude oil movement is not the final say in where retail prices will end up because other factors can, for a shorter period of time, have a stronger influence on retail prices.

The next slide, please. So, let's talk about here's some purposes of what it is used for, meaning the price forecast, which you don't see in front of you at this time. And that is, what Aniss was talking about, vehicle purchases, utilization, how much I drive my vehicle? Do I shift to some other type of mode of transportation because prices are high? And, so, changing prices over time can influence decisions like this.

So, then, you also have other types of price comparatives. I'm looking at compressed natural gas prices, or LNG prices versus diesel price. I'm a long-haul trucker. Okay, Aniss was talking about in the freight model you have payback periods. Change to a fuel and a technology type and it pays back in a certain number of years. Well, how do you calculate that? That's because there's a price difference between the fuels and how many miles you travel for your vehicle, and what the cost of your vehicle is relative to the other technology.

And, so, differences in prices over time, in our forecast, will in the model influence some of the results you see for freight and fuel switching.

The next slide, please. So, here's another example of where you're looking at a chart of the bars are the percent of new vehicles sold in the United States, that are in the passenger car category. Not light truck. The red line is the price of retail gasoline in the United States.

So, price of gasoline rises, consumer, U.S. preference has been a greater percentage of passenger vehicles which, arguably, have better average fuel economy than the light-duty trucks and the SUVs. Prices fall, I'm buying less passenger vehicles, more SUVs.

So, that's why the price forecast is important in vehicle preference by consumers, based on the type of information you have on the cost, the relative cost of the vehicles in their classes, as Aniss was saying, not individual makes and models.

The next slide, please. So, I think Aniss covered this. We're covering, certainly, the traditional fuels, gasoline and diesel, they're the dominant fuels right now, and at least for the foreseeable future.

Natural gas and electricity charging prices are also covered in the division. And hydrogen, jet fuel for the aviation model, propane and E85 are other fuels we will also be projecting prices for, used as modeling inputs.

Not covered, biodiesel, renewable diesel, bunker fuel for marine vessels. We do not project prices for those. Biodiesel and renewable diesel are blends that are incorporated into diesel fuel that goes into commerce. It’s unusual one would be purchasing, especially in the private sector, a B100, 100 percent pure biodiesel or 100 percent pure renewable diesel. So, these other fuels are, really, they would be reflective of what the going price is for diesel fuel at the time.

The only sort of nuance or caveat to that statement is the fact that those different types of fuels will command premiums in the Low Carbon Fuel Standard that will be LCFS credits. So, that has a value to the seller and those credits can be sold to obligated parties and it will be a revenue stream.

So, even if your cost of making those other renewable fuels is more expensive, this is an example of a revenue stream that helps offset higher cost.

The same goes for E85. Ethanol has been, for most of 2016, more expensive than gasoline. And E85 has a fuel economy penalty of about 25, 28 percent compared to the normal blend of gasoline, E10. So, it’s challenging, just on the current market prices, to find discounted ethanol sufficient to discount your E85 price.

But what purveyors of E85 are doing are using the credits in the Low Carbon Fuel Standard that they have imbued in that fuel, and selling those to obligated parties as an additional revenue stream. So, once again, an example of an environmental program providing other revenue stream for retails and even commercial clients to sell those fuels.

The next slide, please. So, our methodology is, as I mentioned, what drives prices for the petroleum-based fuels? Crude oil. So, we look to the Energy Information Administrative, EIA, their Annual Energy Outlook, or AEO. And they do this once a year. they will do an update in the spring. And they have many different cases or scenarios, whatever the word one wants to use.

And what we want to do is try to best align what those crude oil prices are in their scenarios to our three common cases. So, we want to try to be on as much of the same page, at least make sure the crude oil is, as long as we can be. So, we think there's enough cases and selection there to do that.

We'll be making some adjustments to the retail prices that EIA has. Since they don't forecast California retail prices, we will have to make our own adjustments. And, so, higher taxes, higher production costs, and low carbon, and the fuels that are under the CAP fees will be part of our adjustment that we'll be rolling out with our preliminary analysis and showing you what those are.

So, an example can be, where Aniss was talking about, a high scenario and a low scenario, as to with prices, a high-price scenario, for example, could be where the carbon markets are going up to a higher level. Versus a low price environment, where the carbon prices, there is ample supply, they're at a moderate level, likely around where they are today, about $100 a ton. And, so, you don't see a large escalation of the fuels that are under the CAP. But you would see a rise in the market for Low Carbon Fuel Standard because of how you calculate that credit is based on how far away you are from the baseline and your carbon deficit.

So, that program will become more expensive over time, even if one assumes the price of carbon stays at $100 a ton.

So, hydrogen, the last point there, we will be working with our colleagues, in the Fuels and Transportation Division, to come up with a joint hydrogen fuel price forecast. The division is responsible for working with outside parties to put additional retail hydrogen out there, in California. So, there's a great deal of experience and data being collected on what it does cost for these facilities, and what kinds of prices one might expect over the forecast period. So, that's why we want to work closely with them to be on the same page.

The next slide, please. So, just, yes, you have no slides here with the prices, preliminary prices. You'll have to wait a little bit more. In an upcoming workshop, and we'll be presenting that information. And even more important, what are assumptions are that we use and what adjustments we did make to EIA's cases.

And, so, we look for people to give us, at that time, feedback on why did you select those EIA cases? Why did you make those adjustments? Why didn't you make other adjustments? And, so, that would be the kind of input we'd like to see from stakeholders on what we did do. But, unfortunately, I can't show you just yet.

So, any questions?

CHAIR WEISENMILLER: Yeah, I've got a couple. So, you about the carbon allowance price. I just wanted to make sure you ended up consistent with the graph on Lynn Marshall's presentation, page 3? Actually, I'm looking at it right now. But she's got a high/low for Cap and Trade. So, anyway, I wanted to make sure we tie to that.

MR. SCHREMP: Yes, we will be consistent with the price of carbon, which goes directly to fuels under the CAP.

CHAIR WEISENMILLER: Right.

MR. SCHREMP: The Low Carbon Fuel Standard, that's part of the calculation. And, so, we want to make sure, to your point, that we're using the same carbon price in the three common cases, yes.

CHAIR WEISENMILLER: Okay. The other question is, obviously, forecasting gasoline and diesel are very uncertain. So, I'm trying to get a sense, from you, of the range of uncertainty and whether it's symmetrical, or high or, you know, where you think the greater uncertainty is in terms of upside or downside?

MR. SCHREMP: I think the biggest uncertainty -- I mean, when I was showing that one chart, if we could maybe go to slide 2, or 3, the next one, please. So, you see that, I mean we had the mother of all recessions. And that was global, that was U.S., that was quite a commodity bubble burst. And a monstrous drop in crude oil prices and retail prices. I would say highly, highly, highly unusual that did occur. I mean, it did occur, it's an historical event.

But to your point, the uncertainty, I would say based on what's gone on and how our market is a more isolated for transportation fuels in California, and the West Coast in general, that the uncertainty is we have seen several instances of a (indiscernible) in the system that results in what? An increase in price, and a rather significant one at times. Not the opposite.

I mean, so I think going forward you could have an underlying base forecast for crude oil. You might stay in that range over the next three to five years pretty close. But you could, in California, have some very significant deviations in the upward direction because of significant unplanned outages at refineries in California.

So, to your question, I think, yes, the risk or the uncertainty is some of these deviations, we can't predict how many exactly. But we've had enough, now, to have one really good one every other year to have that be an expectation.

CHAIR WEISENMILLER: Okay. Andrew?

COMMISSIONER MCALLISTER: No.

CHAIR WEISENMILLER: Okay, thanks.

MR. SCHREMP: You're welcome.

MS. RAITT: So, our next speaker is Asish

Gautam, and he's from the Energy Commission staff.

MR. GAUTAM: Good afternoon, Commissioners, members of the public. My name is Ashish Gautam, staff members in the Assessments Division. And I'll be going over some of the changes and updates we're planning to make for the treatment of distributed generation in the 2017 IEPR.

First, just a quick review of where we were in 2015 and 2016 IEPR. When we were finalizing the 2015 IEPR, we had some uncertainty surrounding the expiration of the Federal Tax Credit, and the PUCs NEM decision. So, we decided to go and assume that the tax credit was going to expire. At least, that seemed to be the consensus back then. And we created some bookend scenarios regarding net metering. We assumed reform of net metering in the high demand case, and full retail credit in the low demand case. And, then, split the average additions between the two bookend cases.

And when we were presenting in the 2015 workshop, you know, just a week before the PUC gave the solar industry a big win there and, you know, we weren't able to accommodate any of the changes there. At the same time, the Congress passed the extension of the ITC. And, then, so these were some outstanding issues that we promised to resolve in the 2017 IEPR.

In the 2016 IEPR, we looked at some of the issues surrounding forecast PV additions. We had utility staff, federal labs, and the Federal EIA come by, in one of our workshops, to give us an overview on how they approach forecasting PV additions.

We also addressed some of the issues surrounding the whole peak shift phenomenon and the need to go to an hourly forecasting to really handle some of these issues.

And, so, we've listened to some of the feedback we received in the 2015 and 2016 IEPRs, and we've made some changes that we want to address in the 2017 IEPR.

First up is the ever-increasing call for more geographic disaggregation of our forecast. So, Chris has talked a little bit about some of the changes that he's made for us. What remains is to map our consumption profiles from our sector surveys, to the new climate zones. With the new geographic layout, we also have to update our PV shapes.

This third sub-bullet here is a point I think the Chairman made last -- in the 2016 IEPR, about the need to kind of go beyond just the large POUs, mainly SMUD and L.A., and it also coincided with some of the responsibilities the Energy Commission has for the POUs' IRP filings. Staff, in our Supply Office, reached out to us about how we might be able to disaggregate some of our DG forecast to kind of support their efforts there.

So, we're looking at how -- what changes we can make. I think there are 16 POUs in total. Of that six, we already are forecasting, and of the 10 that's remaining, we're still trying to wrestle with what we can do, how many of the 10 we can cover. There are some data issues. It appears a lot of the POUs don't have the load research capability to give us the data we need. We haven't made a decision, yet, but we're still trying to figure out what we can do.

Let's see. So, a big focus for us, in the 2017 IEPR, is the achievement of big PV adoption in the residential segment. This is where additions are really concentrated. PG&E has about 60 percent of their total PV stock in the res sector. Edison has about 66 percent. And San Diego, a lot more, roughly about three-quarters of the PV is in the res sector. And, so, one of the -- can we move to the next slide -- issues we faced was to create more customer profiles to model adoption.

In past IEPRs, we've only used a single profile. So, there was a question of can you really rely on a single profile to characterize all the different residential customers out there?

So, we have expanded our profiles. It seems like every IEPR we address one issue, but a whole bunch of other issues keep coming up. So, you know, this is one effort of trying to get more data to help us create more customer segments to model adoption of. And, so, this is what we are proposing for the 2017 IEPR.

So, the next slide. The other changes we want to make, Lynn presented earlier about some of the efforts she's doing on the time-of-use rates, so we do plan on incorporating the TOU rates for IOU residential customers in the 2019. And I think, I believe we're also addressing it for SMUD. For the other POUs, we've not addressed a whole lot, yet, but hoping to get more feedback on the upcoming DAWG workshop on how we can move forward there.

Regarding net metering, one scenario we have for post-2019 is to look at maybe just giving wholesale compensation based on the TOU periods, and also that Lynn's working on. You know, in the NEM proceeding, there was a range of proposals that stakeholders put out. We'd like to hear more in the next DAWG meeting about option scenarios we could take, and try to look at for the 2017 IEPR.

And, then, the other change is the extension of the tax credit. Obviously, we missed it in 2015. But we do plan to address it for this IEPR. It's been extended until 2021, where there's a phase-out of it. And I think the res credit goes away and the non-res stays at 10 percent.

The next slide, please. One of the other issues we're dealing with is the Net Zero Energy Homes. I believe the 2019 Building Standards are going to try to take this on. So, we are coordinating with our standards -- the building standards on what their thoughts are about net metering, and how we can roll that into our analysis for one of the optional scenarios.

We received a lot of feedback about adoption modeling for PV. And prior IEPRs relied on the payback period. It's the holdover from earlier studies.

Last year, when we had NREL and other staff, other utility staff members out here, they talked a little bit more in detail. And NREL actually had a study that they did, looking at how -- what kind of factors customers are responding to. So, they looked at environmental and economic reasons. The economic reasons were kind of the dominant one, the dominant issue that decided -- that was a factor in them adopting PV.

Within the economic factors that they looked at, there was payback, bill savings, and the levelized cost. And in their analysis, they determined that customers were really responding to monthly bill savings. This had more to do with the whole leasing structure that, you know, the sales staff of the national companies were really pushing.

And, so, we did receive data from NREL about how we could incorporate their survey findings into our process, so we're looking into that.

The other thing that -- other source of data we see from NREL is a new, potential analysis for solar regarding granular geospatial data they have in their possession regarding potential by different building types, and county efforts. Narrower than county, I think, looking at rooftop orientation and just kind of what kind of a lens they are. So, that's another piece that we want to incorporate, and try to map that to our 20 forecasting zones right now. So, that's where we are.

The last part here, energy storage is making a lot of waves here. So, we are looking at incorporating both stand-alone and net payer energy storage. This is still an ongoing work and we're hoping to have some materials for the upcoming DAWG workshop.

The next slide. And just some other updates.

We're trying to think about longer-term about how we can do a better jobs in terms of modeling adoption. And we did become aware of a took from NREL, that they had developed, and last we received approval at the last week's business meeting, to enter into an agreement with NREL to bring this tool in house. So, we're looking forward to working with them on that.

We have a couple of studies underway, looking at changes in load shapes, and new sector surveys. We're hoping to incorporate some of their findings in there. I think for the sector surveys, they might not be finished until 2018, but that's just a timing issue that we have to deal with.

And, then, this last part, we had a workshop early this month regarding coordination on DER, growth scenarios for the DRP. You know, the work always has been that the IEPR Demand Forecast feeds into other processes. But the utility staff have access to much more granular data. And, you know, depending on how they do the studies, their results might depart from the IEPR Demand Forecast. So, what will be the process to align their findings into ours, so there's a possibility that the findings from these other processes would actually feed back into the IEPR. So, this will be a topic for future DAWG meetings.

I believe that is it for me, so I'll take any questions you may have.

CHAIR WEISENMILLER: Well, I mean, I think, again, I'll go back to my normal point that from the Barrier Study (phonetic), it's pretty clear that low income -- you know, owner-occupied housing is one thing. Rented space is a different thing. And at least the NREL stuff I've seen so far hasn't really distinguished. I mean, you may have a lot of sunlight on the roof, but, A, you might not have a very good roof, or you might not own the building.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: So, in those cases, you've got to somehow figure out a way to parse those out.

MR. GAUTAM: Yeah, so what we have done, for the most part, is limit our analysis just to single-family, owner-occupied housing types.

CHAIR WEISENMILLER: Right.

MR. GAUTAM: And there's a lot of effort for the disadvantaged communities regarding community solar.

CHAIR WEISENMILLER: Right.

MR. GAUTAM: I believe that's more on the front-of-the meter type deal, so we're not addressing directly here, but it's not really being ignored. There's a lot of interest going.

CHAIR WEISENMILLER: Yeah, there's a lot of interest. There's not much in California. As President Picker would say, don't expect much. But I don't know how good his forecast is on that.

One of the other things is that going forward you need to keep your eye on potential tax reform. You know, that certainly, if the Ryan Tax Measures pass, and you get to a marginal tax rate of 15 percent, that's going to have a big impact on a lot of the leases.

MR. GAUTAM: Yeah.

CHAIR WEISENMILLER: You know, going forward. But, certainly, as costs go down on the solar systems, they're going to be less dependent on the least side of stuff.

MR. GAUTAM: I think, roughly three or four years ago, leases we remaking the dominant share. But now, I think what we've looked at is about 60 percent or so interconnected in the IOUs are owner owned.

CHAIR WEISENMILLER: Yeah. Another thing would be to look at -- Borenstein has some pretty good data that he's tried to parse out on the income distribution of solar adopters. You know, they tend to be -- and he's tried to go through it census tract by census tract, and spin that out. So, that's sort of another --

MR. GAUTAM: Dimension.

CHAIR WEISENMILLER: -- another dimension to look at. Obviously, the early adopters tend to be wealthy.

MR. GAUTAM: Right.

CHAIR WEISENMILLER: But that also, at the same time, I think a lot of the battery interest is basically upselling. If you've got a lot of early adopters who, you know, have had a solar system, it's pretty easy to go back and sell to them. It's easier to sell to them the batteries than to the low-income places.

MR. GAUTAM: What we've looked at NSHP (phonetic) data is that most of the storage is really stand alone. We haven't seen much uptick in NEM there,, yet.

CHAIR WEISENMILLER: Uh-huh.

MR. GAUTAM: But, you know, depending on how the net metering decision goes, that could really switch things up.

CHAIR WEISENMILLER: Yeah. Andrew?

COMMISSIONER MCALLISTER: Yes. Okay, so, yeah, thanks for that. And, you know, it's good to see the sort of continuity from the last couple of discussions, and you're following through on the issue of the day, and making progress on resolving them. So, that's great.

I wanted to just -- this idea of granularity and, you know, the whole process of all the forecasts as moving to be more granular. So, just really a broad encouragement to say, you know, let’s be ready for having very granular data, at some point, that we can use to match up with the other kinds of information we have, demographics, et cetera. You know, ZIP plus 4 (phonetic), or even more granular than that, you know, depending on how we want to do projections on going forward.

MR. GAUTAM: Yeah.

COMMISSIONER MCALLISTER: So, you know, the 802 benchmarking data, you know, so that will include much of this multi-family population, and we’ll know about those buildings and, hopefully, we can do some segmentation.

MR. GAUTAM: Yeah.

COMMISSIONER MCALLISTER: You know, low income, market rate, different sizes, different types, different jurisdictions, different program impacts, for example, that will effect diffusion of solar.

MR. GAUTAM: Yeah.

COMMISSIONER MCALLISTER: So, I think that’s very exciting and I think it will really help our -- help do better local projections.

Let's see, I guess an encouragement to align on the TOU front. I think you may have said that, already, but the Chair may have said that already. But, certainly, the scenarios that Lynn talked about earlier, and what the PUC's working out, you know, we definitely want to have the same suite of possibilities and have that aligned across the various sub-forecasts.

And, then, I had a question. One other sort of recommendation is you mentioned, along the way, that you're coordinating with the Building Standards Office, which is great. I think there are a whole bunch of areas, actually, a number of areas where they are asking similar questions. So, how NEM is going to work out, you know, I think we're all interested in that and there's a lot of work going on. And, certainly that impacts the cost effectiveness of the Building Standard development. You know, measures that do or don't pass muster, depending on the NEM scenario.

MR. GAUTAM: Yeah.

COMMISSIONER MCALLISTER: But, you know, would also, would encourage you to talk with them about that, and about how storage is characterized, because they're also thinking about that.

And, then, finally, a question. On the POUs, are they collecting the individual system information?

MR. GAUTAM: Well, I believe they all --

COMMISSIONER MCALLISTER: The interconnection information?

MR. GAUTAM: So, from the IEPR, we do get interconnection data. We make a request for most payers, only POUs with 200 megawatts or higher report. So, we do miss -- I believe there's like 45 or so POUs, but we only capture about a dozen or so. So, there is a gap that we have for the other ones.

We've relied on the SB1 POU report. But this is the last report, I believe we'll be getting from there, so there will be an issue there about data gaps.

COMMISSIONER MCALLISTER: Okay. So, I guess -- go ahead.

CHAIR WEISENMILLER: I was going to say, we may want to talk to MCP and CMUA about continuing that report, if that would be helpful on the data side.

MR. GAUTAM: Yeah, we'll follow up with them.

CHAIR WEISENMILLER: Okay.

COMMISSIONER MCALLISTER: You may have brought that up. The IOUs are supposed to be, you know, basically continuing that databased, based on interconnection data. And I guess last year we had this discussion a little bit, and it seemed like some of the fields that they had been collecting under the CSI were falling away. I guess, maybe, do you have an update on all of that?

MR. GAUTAM: Let's see, so in terms of CSI -- the fields that -- from what I understand, a lot of the fields are still being collected, but there was a gap between when the CSI data collection stopped and when the IOUs started collecting the extra fields, so there is a gap there.

I'll have to get back to see if there are other issues regarding collection on those fields. I think one of the issues we've had is the solar tilt and orientation seems to be not as clean as we had hoped, so that's an issue when we're trying to characterize the generation profile.

COMMISSIONER MCALLISTER: Anyway, I agree with the Chair that it would be great to have that be truly statewide, smaller POUs notwithstanding.

MR. GAUTAM: Okay.

COMMISSIONER MCALLISTER: Okay, thanks.

MR. KAVALEC: Hi. I'm, once again, Chris Kavalec. And my final presentation, today I'm going to be talking a little bit about our timeline, a little bit about the way that we forecast, summarize that, and then talk about the remaining important inputs and assumptions that are going into the 2017 IEPR Forecast.

The next slide. So, our timeline looks like this. First off, just a reminder, the 2017 IEPR Demand Forecast is a full forecast, one that we do every two years, as opposed to the forecast update that we did in 2016.

The first step has already been taken. We've requested the information from the utilities, including their own forecasts, in our demand forms and instructions that have been sent out. And most of them are coming back this month, and then some are coming back in April.

Here we are, today, in our Workshop on Forecast Assumptions. And we will get to work on the forecast and have a workshop on our preliminary forecast in early August.

And at this workshop we will typically compare our forecasts to those of the utilities, in an attempt to reconcile any differences we may have. Taking that information, along with other comments from stakeholders and internally, we will develop a revised forecast and have a workshop sometime in December of this year.

The next slide. As far as the way we forecast, you've all seen this before, I'm sure. We, basically, forecast using a bunch of different sector models, residential, commercial, industrial, TCUs, as was mentioned earlier. We have, our residential and commercial models are full end-use models.

We also incorporate the transportation energy forecasts, and self-generation that Ashish was just talking about.

All of these results get aggregated, and summarized, and calibrated in our summary model. And, then, the summary model provides annual data to our peak model, which applies load shapes to give us an annual peak. And, also, I put in there hourly model. That's going to be integrated with our peak model.

On the sort of the top left there, what I'm going to be focusing on, in terms of additional input assumptions, we've already talked about the economic and demographic inputs. We've talked about self gen, and electrification and electric vehicles, TOU rates.

Some of my remaining discussion on inputs and assumptions is focused on efficiency and demand response.

The next slide. As is confirmed by this slide here.

Okay, the next slide. For efficiency, in our demand forecast we distinguish between what we call committed efficiency savings, and that means savings from efficiency initiatives that have been finalized, approved, and/or already implemented. And that includes codes and standards, as well as utility programs.

And the other category is efficiency reasonably expected to occur in the future, through future programs and updates to codes and standards. We refer to that as additional achievable energy efficiency, or AAEE.

So, what we call our baseline forecast includes only the committed efficiency. And, then, we adjust that baseline forecast to account for AAEE, and that gives us a managed forecast that is used in the State for resource planning purposes.

The next slide. So, first off, a little about committed efficiency. As we move from forecast to forecast, some of the efficiency initiatives, previously considered AAEE, become committed. And, therefore, have to be integrated into our baseline forecast.

So, for this forecast that includes what’s listed here. A new update to Title 24, in 2016, 2016 Appliance Standards. We also have 2016 and 2017 IOU programs, previously AAEE, but are now fully funded and implemented. And, as well as 2016 POU programs.

The next slide. As far as AAEE savings, because of the timing of the various analyses, we’re not incorporating a new round of AAEE savings until the revised forecast. It won’t be in the preliminary. More specifically, the IOU 2018 and beyond efficiency goal setting is not going to be completed until August. And from those, we derive our AAEE savings.

And for POUs, again, this will be in the revised forecast. But that will come from potential studies and individual utility plans, along with target setting related to SB 350. And just a little bit about SB 350. This is the way I see it working, and the Commissioners can correct me if I'm misguided here. For the IOUs, the CPUC, through their goal setting, will decide how aggressive they're going to be in lieu of SB 350. And those goals will give us, at least for our mid-case forecast, the IOU contribution to the SB 350 targets.

On the POU side, our AAEE is going to come through a combination of existing potential studies, individual utility plans, and what the Commission comes up with through our target setting process for the POUs, for SB 350.

The next slide. The other category is here load-modified demand response. We include some demand response on the demand side. That is specifically programs that aren't integrated, fully integrated into the CAISO market. That includes, at the moment, two subcategories, non-event based, which includes the time-of-use rates and permanent load shifting. And event based, which is peak pricing and peak time rebates.

We get estimates of the savings from those programs, from IOU Load Impact Reports that come out every April, and are vetted through the CPUC process.

In the past, the impact of load-modifying demand response has been in the couple hundred megawatt range for the IOUs, combined. Of course, this time it will be higher because we're integrating more default TOU rates. So, expect a significant change in the amount of what we call load-modifying demand response.

The next slide. Other miscellaneous assumptions. We incorporate climate change impacts into our forecast through scenarios, temperature scenarios provided by the Scripps Institute of Oceanography.

We discussed, before, transportation electrification, including EVs, and high-speed rail, coming from our Transportation Unit.

Project CHP impacts, in terms of on-site generation, are provided to us from our Supply Analysis Office in the Division.

And kind of a fun topic here, the impact of legalized marijuana. We hear stories of marijuana growers crashing the grid in Oregon. And in our Econ Demo Workshop, we had a representative from the ag industry, and he mentioned that the impact of marijuana was probably one of the more significant impacts or determinants in how much growth there's going to be in the ag sector, in California.

So, this is probably not something we can build in directly into the forecast, yet. But I think it warrants at least some discussion about potential impacts.

So, that does it for the demand forecast.

CHAIR WEISENMILLER: A couple questions, Chris. One of them is the sort of proverbial elephant in the room. On the energy efficiency side, one of the things we have to figure out this year is what the new Administration means in terms of Federal programs. You know, at this point it's all sort of oh, my God. But, presumably, between now and forecast adoption we'll have a better sense of exactly what they're doing.

MR. KAVALEC: Yeah, and in terms of estimating those impacts, I was thinking that this could be done through, at least for the IOUs, the potential study. And including in the potential study more and less aggressive amounts of Federal standards. And because you need to -- you can't just do it in isolation because if you make a big change in the Federal standards, that's going to impact how much savings you're getting from the program side. Anyway, that was the way I envisioned that.

CHAIR WEISENMILLER: And I guess the other question is the reality is there's already marijuana growing in California. How large the loads are we don't know, and how much is either connected to the grid or not connected to the grid. And, so, in a way we're trying to figure out what the legalization could mean in terms of deltas?

MR. KAVALEC: Uh-hum. Yeah, and it really depends on how the industry shakes out and how fast it shakes out. If it remains a bunch of small growers, in their greenhouses, that's one thing. If it transitions quickly to large growers, which means more energy efficiency in terms of production, that would be -- that would have a significant impact on your energy forecast. So, like I said, it's probably too early to try and do something relatively cohesive and precise. But it at least warrants some discussion of the issues involved.

CHAIR WEISENMILLER: Yeah. And, certainly, if it's possible to get any -- any information that anyone has on so far what's going on, or what's going to happen, you know, it would be interesting to sort of feed that in.

So, you're right, I think this year is one of more collecting information, trying to think about what next steps are.

COMMISSIONER MCALLISTER: There is at least one proposed utility program to target that sector, actually the marijuana sector, with efficiency. So, there's some anticipation that this will be a relatively big deal.

And I, you know, on a few of those real estate sites, you know, there clearly is a submarket, now, and I think a thriving market on buying and selling properties that lend themselves to marijuana cultivation. So, you know, certainly it's coming, so we need to be prepared.

I just had a couple of questions.

(Inaudible comment.)

COMMISSIONER MCALLISTER: Yeah, exactly. And I guess there's also the Fed overlay of the legality of the whole thing.

So, let's see, so I guess I want to just build upon something you said. I'm glad it's happening. So, I agree with your characterization of the AAEE, and sort of what it's going to be based on. And just encourage the forecasting team to really keep tuned into the IRP process, and to the goal-setting process, itself, and sort of how that plays out, you know, with the POUs.

And I guess the idea is that the doubling, part of the doubling will be -- will fall into that relatively reliable AAEE category and part of it will be beyond that, and more of a market transformation aspect, and we'll have to encourage different things as they happen, and that will be more of an iterative process going forward.

But I want to make sure that we're not confusing the issue by talking about different kinds of AAEE and really trying to focus on, you know, in the IRP process, have that resource be talked about as such, and have that mean the same thing as it does when you're talking about it in the forecasting context. I think that's important because it's already confusing enough, so we don't want to confuse people further.

the other thing I want to talk about a little bit, and maybe get some ideas is, you know, as the AAEE from one forecast moves over to be committed in the next forecast, I think that's entirely appropriate and I think, you know, makes a lot of sense.

On the other hand, when we do talk about the long-term impacts of efficiency policies, we tend to kind of lose what got subsumed into the baseline. And, so, keeping a long-term view of what has happened, you know, what used to be considered AAEE or additional, and now is not, still sort of coloring that a different wedge. Or, at least having the ability to crank out the graphics that show that as a different wedge, than just subsumed down there in the baseline I think is important for the narrative. I mean, because the narrative is that we've been doing this for a long time, and a big chunk of what's now baseline energy consumption is as low as it is because of the efficiency. And that's not clear just from the individual IEPR, you know, forecast in a given year discussion.

So, I want to work with you to produce some of those kinds of visualizations of, you know, what we are taking advantage of, what benefits are we accruing, today, that are actually the result of what once was additional? So, I think it's important to kind of do both things in the present, and then also have the long-term view.

So, I guess my question is, you know, can -- do you have the levers and buttons to push to be able to do that?

MR. KAVALEC: Yeah. In terms of the standards, we model each set of standards individually, so it's easy to break out a given set of standards. And the programs, we also do year by year, so we keep track of a program year to year, or year cycles. So, yeah, that should be no problem. It's just a matter of sitting down and talking about specifically what you want to see, and I think we can do it.

COMMISSIONER MCALLISTER: Thanks, Chris.

MS. TANGHETTI: Okay, good afternoon. I’m Angela Tanghetti, and I’m with the Supply Analysis Office of the Energy Assessments Division.

So, as you notice from some of Chris’s slides, early on of the process flow, that the production cost model, or as he referred to it, as the electric dispatch model, is the first model to be run in this IEPR analytic process.

So, we’re not only the first team to provide -- you know, to start input assumptions, but also to provide some simulation results here, today. Since these production cost model simulations from PLEXES, which is the production cost model we use here at the Energy Commission, is directly used as input to the NAMGAS model, specifically the natural gas use for electric generation in the WECC.

So, the next slide, please. So, as you can see, the topics that we’re going to cover today are, you know, the load forecast, the load profile updates, some energy efficiency projections, some OTC compliance plan updates that’s different from the 2015 IEPR. Our hydro generation projections have been updated. And from that, we have also the RPS projections in different RPS portfolios. And, then, we're also going to present some selected simulation results.

What's not here, which we also have in our tool, is the GHG projections, which Lynn presented earlier, so those are also embedded in our simulation model.

And we've also incorporated some updated Burner Tip prices that are based on the final IEPR NAMGAS results, as well as the GDP Deflator that's been updated for the 2016 updates.

Jason Orta's the next presenter and he'll probably go over a slide on that.

But just some noteworthy differences that have impacted, slightly, some simulation results from the 2015 Final IEPR Burner Tip prices is that we're noticing less of a margin of gas prices between Northern and Southern California, so the deviation is really narrowing.

And the gap is increasing just slightly from the southwest prices to Southern California. So, the southwest is becoming a little bit cheaper throughout the forecast period, compared to the Southern California prices.

Another update for this IEPR cycle, that we're kind of proud of, is that Paul Deaver, a colleague of ours in the System Modeling Unit, spent many months refreshing our generator heat rates. And this was based on 2010 to 2014 SIMS data, which is hourly reported of generation and fuel use data. And this is for all generators in the WECC.

So, right now, this Heat Rate Report and the heat rate details are in the review process and we hope to have that posted soon.

And it's interesting, for some of the observations, is that previously we modeled vintages of combined cycles that were, you know, based on the years they were built. Say, 2002 to 2005, 2006 to 2010, and 2011 to present. So, everything in that vintage, basically, had the same heat rate curve. But now that we've utilized some SIMS data to look at this, we've noticed that some of the heat rates have some degradation in them, as opposed to what we previously thought we observed. And we're trying to understand whether this is more of an owner type of maintenance policy, or whether it's because of more cycling of these combined cycles. So, there is a slight degradation in some of these heats rates. So, we're going to do a little bit more research to see if we can understand the reasons for this degradation in heat rate. Not all of them but, you know, each one has a personality, so we've been able to capture that in these updates of our heat rate curves.

The next slide, please. What I kind of wanted to go over here is everybody talked about their three common cases, and we've kind of introduced this fourth common case. And we're calling it the high EE common case. And I'll go over the exact projections in a later slide. But we just wanted to let you know that this slight -- this case is, basically, just an informational effort. And it does not attempt to predict how policy issues will ultimately be addressed.

There's a parallel 2017 IEPR technical analysis underway, with the recent staff report and workshop last month, and it was called "The Framework for Establishing the Senate Bill SB 350 Energy Efficiency Savings Doubling Targets."

So, this staff paper was presented in a workshop about a month ago and there's a link to it on our website.

So, go ahead to the next slide. This is just a link to the load forecast updates that we've included in the rest of the WECC load forecast that we have used, as well. So, again, these are just linked to those forecasts and how we extrapolated the TEPPC forecast to the years 2027 and 2028, which this IEPR cycle's going towards.

The next slide. It's hard to try to figure out how to present this data, because there's so much of it, because we modeling the WECC. So, I just kind of wanted to go -- since we've gone, in other workshops, over the updates to the demand forecast, I just wanted to show a little bit about what we're assuming for out-of-state load forecasts.

And, in general, the 2017 preliminary forecast is less than what we assumed in the 2015 IEPR, for regions outside of California.

What we don't show here, too, is also we do develop a high and a low demand case for regions outside of California. Previously, in the 2015 IEPR, we used the TEPPC common case assumptions, which was just kind of a gross estimate of 10 percent above or 10 percent below the mid case, which caused some big variations.

And, so, what we decided to do this time was take the same differential between the high and the low that California is assuming. It's just kind of -- it's hard to gather that kind of data for every region in the WECC, so we just are trying to assume as California goes, potentially the rest of the WECC goes. A simplifying assumptions, but we did try to generate something for the rest of the WECC for a high and a low.

Go ahead, the next slide. Oh, another -- this was a long overdue update on our team's part. And, again, Paul Deaver, as our staff who's kind of replaced me as a lead heavy data lifter, updated our Mr. Load Shape tool. And it's a tool that takes recently hourly load data for LSEs, or balancing authority areas in the WECC. For California, we're able to obtain a lot of the LSE data, which is better on a BAA basis, because each LSE does tend to have its own kind of individual load shape. So, we're able to gather that more. So, in California, as we get further and further from California, sometimes we're just limited to the BAA or sometimes the utility is able to provide us hourly loads. But we have to have a consistent set of data. It just can't be 2014 here, 2015 here. We want to develop the same forecast period.

So, for this update, we used 2009 to 2013 hourly loads to generate hourly load curves for all regions in the WECC that we're doing load forecasts for.

And, in general, this did cause the hour -- the peak shift hour in our historic load shape. So, we're looking at the peak load hour, in general, going from hour 15 to 16, shifting to hour 17. But, again, it's definitely each LSE has its own personality, so there's been different shifts in different regions.

To this historic load shape, we then are able to study the impact of the behind-the-meter PV and AAEE projections, because we do have hourly profiles to describe those, as well. So, we're able to understand a peak shift throughout the forecast period, as well.

We're not only seeing a trend in the peak shift hour, but also the peak shift month. It seems to be shifting later and later in the summer, at least in California.

And we did use the same -- were consistent with the Demand Office on their PV profiles and hourly AAEE projections.

Okay, the next slide. Again, these assumptions have already been covered in another workshop, but I just wanted to provide a link to exactly what we're assuming in the production cost model.

And I just wanted to note that the TEPPC common caseloads we're using are what they call Version 1.5. I think they're up at 1.7, now. But at some point we have to hold off. So, maybe in our revised forecast. Not maybe, in our revised forecast we will include more current assumptions from the TEPPC common case.

The next slide, please. Here's our specific assumptions for that fourth scenario that we talked about. And these are the details, again, for our high AAEE common case. And, again, this only impacts

California loads. We didn't develop high AAEE or EE projections for other regions in the WECC. And, again, these are simply developed projections and they're going to be replaced by more in-depth analysis being conducted in parallel processes through the IEPR. So, again, it's just a very simple approach. And, again, this is just an illustrative case that we'll be running to look at the impact on RPS targets and natural gas use.

COMMISSIONER MCALLISTER: Just a quick clarification question. So, this is the high AAEE -- this is basically the doubling scenario, right?

MS. TANGHETTI: Yeah.

COMMISSIONER MCALLISTER: Okay, so it's not the high AAEE in the forecast terminology. Okay, so, I got a briefing yesterday on this, and other things, and looked at this. And these numbers actually do go along well with the conversations we're having about what the doubling goal looks like.

I guess my suggestion, which I've sort of mulled over since then, would be maybe to call this a high EE scenario and not a high AAEE scenario. And that way it's clear that it's sort of, you know, all of the above efficiency and not just what we're calling, more surgically, AAEE. So, that's the only change. Otherwise, I think it's great.

MS. TANGHETTI: Oh, and, yeah, just to make it clear, again we're -- again, this is our preliminary, so we're working to refine these things. And, yeah, we struggled with the name for this one, for the longest time. So, again, we'll consider that in the future. Thanks.

Okay, so the next slide. This is just a kind of a little overview of some of the OTC changes. And, mainly, the Encina is of interest. It's been pushed out a year. Encina One, we're looking at retiring the first quarter of this year.

Moss Landing 6 retired as of last December. And, then, the Diablo Canyon, we're assuming that they're adhering to the Joint Proposal Settlement Agreement, with Unit One going out in 2024 and Unit Two going out in 2025. This is a little bit different than the current OTC schedule, but we've been assured that PG&E will update that filing with the State Water Resources Control Board.

Again, and these are the same in all common cases, high, mid and low.

Okay, the next slide. This is just of interest. We just wanted to show what the hydro projections, because hydro projections do impact gas use in our model, and how they have evolved over time. And 2015 definitely is the lowest, with 2016 looking much more promising.

For our revised simulations, we plan to include the 2015 hydro generation in our average monthly hydro projections. In PLEXES we used average monthly hydro projections based on a rolling, 15-year average. So, those do continue to -- the same average value is used every year throughout the forecast period because we are building average load shapes, we're using average temperature conditions. So, we've just gone ahead and used our average hydro conditions.

So, by April, we plan to have a complete set of scrubbed 2016 monthly hydro generation that we'll just roll into our next forecast.

And the impact of -- the next slide, please. So, for California, we're just showing the impact of one more years' worth of hydro generation. It really, basically, had no impact in our hydro projections for California for the 2017, compared to our 2015 IEPR projections.

Okay, the next slide. The next slide is the rest of the WECC. So, this is a little bit more interesting. Incorporating another years' worth of hydro generation did have an impact in, specifically, the northwest region. So, hydro projects, just with this one year, have gone up for -- in the 2017 IEPR, compared to the 2015 IEPR. And, again, this has an impact on gas use, so that’s an interesting update.

Okay, the next slide. These are our annual RPS targets compared to the 2015 IEPR. In the early years it’s similar. Again, driven by a slightly different demand forecast. Our demand forecast is lower for the 2016 IEPR update, than in the 2015 IEPR. And you’re going to see significant differences by the end of the forecast period because, in the 2015 IEPR we assumed that 33 percent persisted from 2020 on. And in this IEPR cycle, we’re looking at 35 percent RPS targets in the year 2021, up to 47 percent by the year 2028. So, these, again, are our RPS targets for each scenario.

Okay, the next slide. Okay, this slide has caused -- now, we’re on simulation results. I’ve kind of gone through some of the key inputs. This slide caused me some deep thought and, well, angst, really, and to understand the drivers for the drop in the 2017 forecast values, in the early years, compared to the 2015 IEPR.

Oh, no, no, no, back on the California side, that one. That one’s where I’m still on, is this one.

So, you know, this is just an example of assumptions driving forecast. So, what we want to go over here is some of the key assumptions that have driven this drop. And modeling assumptions, as well as data assumptions.

And the first, again, is the 2016 IEPR update has a lower starting point, but not that much lower, so compared to the 2015 IEPR. Well, except for the exception of LADWP, but we're looking at it statewide here.

So, in this round of IEPR simulations we added or replaced some modeling constraints. And the first one we added was that we're now requiring all generation that's contracted for, that's out of state, be delivered to California via contractual pass. And the reason we didn't include this assumption before is we thought, you know, this generation, significant amounts are forecasted -- the contracts are forecasted to expire throughout the forecast period. And that, you know, we have this trend toward ore regional coordination, so let's not hardwire these imports into California.

But what turns is just looking at two years' of EIM data, now, that it really hasn't, significantly, in the near term changed dispatch. So, that hardwiring these imports into California, be it renewables, nuclear, and a little bit of coal that's still left out there, a small amount of hydro, that we are driving down some of the gas generation in California, as well as kind of seeing a little bit higher levels of imports.

And, then, the second thing is we've also removed the Cal ISO local min. gen. constraint. And in the previous set of modeling we said that for all regions in California you had to have 25 percent of your generation being met locally, by gas-fired resources.

And, now, what the ISO is recommending in our simulation modeling, and what they have implemented, is something called the NERC BAL 003. It's a frequency response obligation. And what this turns out to do is actually be less binding than the 25 percent local min. gen.

So, the ISOs have observed this in their simulations, and they're trying to recalibrate their frequency response model to see if, in fact, these generators really are, and can't respond as quickly. So, we might be a little bit increase in that, but for now it's not as binding as a local min. gen.

However, for L.A., SMUD, and IID, we still do implement a 20 percent local min. gen. constraint, so there is still that there.

We may look at for -- I was having discussions with the ISO, they just presented these results last week. And they said, for San Diego and the greater Bay

Area, we may want to consider adding some kind of local min. gen. because the ISO, as a whole, the frequency response, some of it needs to be more localized. So, we may look at enhancing that. But it still won't bring the gas generation up to the levels that we were forecasting in the 2015 IEPR.

Yeah, so we're also observing more renewables on the margin, certain hours of the year.

We've also incorporated a 4,000 megawatt net export constraint. Whereas, in previous simulations we allowed a free flow of exports. And, you know, right now the bound is 2,000 and 5,000 for specific cases in the LTPP, or the PUC's IRP process. But, again, that's only Cal ISO wide. So, 4,000 megawatts, we don't really have a strong analytic basis for it. But we, through this process in the next few months, we're hoping to work with either a contractor and looking at historic data to kind of try to calibrate a more robust net export constraint.

Minor drivers, again, is the Burner Tip price deviation between Southern California and the southwest. So, that's it for the California slides.

So, when we go to the next slide, we look at WECC --

CHAIR WEISENMILLER: And I just want to note that if you think about this years' actual hydro conditions, the gas burners are going to be dramatically decreased.

MS. TANGHETTI: But we've tried to look at 2016 generation data so far, but we don't have enough in, yet. And, so, what we did is we looked back at 2015. And 2015 is definitely higher than what we're seeing in 2017, but it was one of the worst hydro generation years.

So, we think we're doing a better job in calibrating to history, now, with this -- with these updates to the simulation. So, yeah, hydro generation does have an impact and what we assume here is average hydro conditions.

So, now going on to the WECC wide, now we see, in general, the gas use is just basically redistributed. So, instead of it being more California-centric, based on our assumptions in our model, we still have kind of the same range of gas use on a WECC wide basis. So, other regions had to step up for the assumptions that we made in California about local min. gen. and kind of allowing the generation that we're contracted for to stay in those regions.

And, then, the other thing is we have a narrower band in this set of fuel use results. And that's because we're using the differential between the IEPR update high and the IEPR update low cases, instead of just 10 percent higher and 10 percent lower for the high and the low common cases.

I think -- again, through this process, we also would like to present, at some future IEPR workshops, the GHG implications of these scenarios. But they're, basically, just hot off the press this week. So, we're struggling to get the data out there because we owe results to the NAMGAS team. So, we're in the process of being able to provide more interesting simulation results in a future IEPR workshop.

So, I think that's it. Do you have any questions?

CHAIR WEISENMILLER: Yeah, I've got one comment and one question.

MS. TANGHETTI: Okay.

CHAIR WEISENMILLER: And I'll start with the question. When you talk about the WECC going from plus or minus 10 percent, to matching the California delta, is that the California delta on a percentage basis, or on a gigawatt basis?

MS. TANGHETTI: It's on a percentage. We it based on the net energy for load and on the peak forecast.

CHAIR WEISENMILLER: Okay, that's good. I was also going to note, on the turbine question degradation, what I was told, historically, by some of the generators is they go through, say, a major maintenance, say, every five years. And they will see degradation until they do the major maintenance. And at that point, actually, may even pick up the new BISRAM model, you know, parts from GE and get better performance than they had the first time.

But generally, so one of the questions as you look at the data, is if you can really pick out when -- if any major maintenance occurred and you may, again, see a performance enhancement then.

MS. TANGHETTI: Right.

CHAIR WEISENMILLER: At least a return to the original, if not better.

MS. TANGHETTI: That was another thing that Paul Deaver's going to look at with this data, is looking at that, as well.

But even with the time period that we're looking at, in some of the same vintages, just some generators seem to have more aggressive maintenance policies than others. So, that may be part of it, too. Some may replace them sooner and some maybe replace them later.

CHAIR WEISENMILLER: Well, we certainly had the one unit we lost down, you know, between -- you know, at PG&E and Edison. And, basically, what the owner had said was they had just deferred -- they didn't have any money, so they deferred maintenance until finally something went and, now, the plant's dead, you know.

COMMISSIONER MCALLISTER: It seems like the other thing is that, you know, maybe their business model might have shifted, or just the dispatch that they're receiving shifts, so their capacity factor changes, or they -- you know, they're just -- what am I trying to say? Just they operate more hours at, you know, some non-optable [sic] -- you know, in one position or other of efficiency. And, therefore, maybe their heat rate goes down as a result.

You know, operating at a lower efficiency with a different kind of call.

MS. TANGHETTI: Yeah. If there's stops and starts that are impacting these degradations, as well.

CHAIR WEISENMILLER: No, I remember when Edison sold off its plants, the VP at the time told the workers that, historically, they used to have like six starts a year. And, now, they're like two to three hundred. So, it was going to be they needed -- they told the workers to really be prepared to, you know, turn the thing up and down more than ever before, but amazing.

COMMISSIONER MCALLISTER: So, they're heat rate would go down.

CHAIR WEISENMILLER: Yeah.

MS. TANGHETTI: Okay, thanks.

CHAIR WEISENMILLER: Okay, thanks. I think that's all we have.

MR. ORTA: Good afternoon. My name is Jason Orta and I'm with the Supply Analysis Office, in the Energy Assessment Division.

The next slide, please. So, I'm here to discuss the inputs and assumptions behind the North American Market Gas Trade Model, which has been referred to here and which I'll refer to as NAMGAS.

They key word here, in terms of that model, it's a North American model. So, the model simulates natural gas supply basins, pipeline infrastructure that's connected to them, which is connected to demand centers.

And this is an iterative model. It iterates back and forth between these components to find and economic equilibrium at all nodes. So, what we get out of this model is a forecast of prices, demand and supply.

The next slide, please. So, this model is run on the Market Builder Platform, which is a platform produced by Deloitte. And, basically, in order to do these forecasts well, we have to reconstruct the way the natural gas market looks like in North America. And, so, it's changed a lot in the last couple of years, so staff has been incorporating these changes.

The model will include the assumptions in the California portion of the model to account for the common cases, which have presented already.

In recent years, there's been quite a bit of change in the pipeline system capacity in North America, as last IEPR, in this presentation they discussed the new resources, fairly new resources coming online in states, such as Pennsylvania and Ohio. But after that, some of the infrastructure to transport that gas to the south, towards the Gulf of Mexico, has come in, in the last few years. So, we include that additional pipeline capacity.

And closer to us, there is additional pipeline capacity going in from Texas, and Arizona, and New Mexico into Mexico, which expects to have a substantial increase in natural gas demand over the next 15 years.

The market is becoming more internationalized, as additional liquefied natural gas export capacity has come online and is under construction.

And another change that we've done with this model is our approach to it, is the staff approach to it. So, it's more of a team effort than it used to be. And staff, working in conjunction with our technical support resources, so that, you know, we have multiple eyes on this model. There's a lot of inputs going back across time, and across space. And, again, which is the North American Continent, 49 states, Canada, and Mexico.

The next slide, please. You've heard this already. These are the assumptions we are going to -- the scenarios we're going to build for this model.

The next slide. An important -- so, what we have to simulate is supply and demand of natural gas. And, so, on the supply side of things, the model distinguishes between proved and potential resources. This is an important distinction. By proved, we mean resources in which the capital has already been invested, but there's some operational costs to be incurred in the future. Potential resources are underdeveloped resources, in which capital costs have not occurred.

And, so, the costs of developing these resources define -- you know, these are technically recoverable resources and they're more likely to be developed as prices rise. And, so, which, if you look at the market in its current state, we've had production go up each year for the last ten years. Prices are very low and we're probably not going to see many of these resources developed in the near future.

The next slide, please. So, just to give you an idea about additional resources, this graph here compares the user supply cost curves. The one on the left is the supply cost curve in the 2007 IEPR reference case, compared to the 2015 case. And we're going to get updated data from the Colorado School of Minds' Potential Gas Committee, in April, to update this.

But as you can see, basically, this is the -- this is, basically, because of the advent of fracking, and shale, and extraction of gas from shale, you see the cost curve going to the right, which means more can be produced at the same cost.

The next slide, please. A lot of the time that we spend on this model is trying to build reference cases for demand. And this means putting in information, demand-type information for the 49 states, Mexico, and Canada. So, this is done through what we call the small M model, which is a model within this large model. And, so, this model will include once we -- we're currently building the reference case. And once we're ready to input, for instance Angela's data, we will modify this to include modifications for California and the WECC.

So, the next slide, please. So, what we do is we model demand in five sectors, residential, commercial, industrial, power gen, and transportation. So, a lot of this relies on recent historical demand for gas. That, you know, basically, that what's happened in the past is an indicator, not the complete indicator, but it's an indicator of what will happen in the future.

So, in the area of residential and commercial, the variables we use are mostly similar, historical demand population price, and so forth. The difference is that in commercial we don't incorporate population as a variable. But in residential we do figure that more people need heating when it gets cold in the winter, if there's more people around then, potentially, you'd have an increased demand for heating.

So, we also look at the industrial sector. In modeling, the assumptions are a little bit different there. We include industrial production. And, also, all the demand factors incorporate various types of weather. So, cold weather in the industrial/commercial, and in residential. So, we incorporate cold and hot weather.

But in power generation -- the next slide, please. Power generation, we also -- and this is a very important sector for, you know, obvious reasons. You know, we're all concerned with the interaction between gas, the gas system and the power system. So, what we look at here, we look at costs of other fuels that are used to generate electricity, hydroelectric and renewable generation. Which, just looking at EIA's data for 2015, natural gas use in the power sector, you see a pretty good spike. And part of the reason for that is, is that, as Angela showed you in her slide, there was a decrease in hydroelectric generation in the Western United States.

But also, since we have to pay attention to natural gas demand in the rest of the country, you'll see that other utility fleets in the South, in the Midwest, and the East Coast, are switching more to natural gas. And, so, we do see that in the data.

We also include -- we have a demand -- we model transportation demand, as well. And this is, in terms of gas use, this is a very small portion of gas demand in California and throughout the country, but we do include that in our model.

So, the estimated price elasticity, as you can see it on the screen there, this is given to us by the Baker Institute. And we assume that the demand for gas is a fairly elastic one because of, for instance, the availability of substitutes and, you know, the ability to choose to whether -- for instance, residential, you can use a blanket instead of turn on the heater, for example. But I'm not cold right now. I know some other folks were, earlier.

The next slide, please. Oh, next slide. Thank you. So, we talk a lot about what goes on in North America, as it's inputted into this model. And, so, we -- one of the purposes of this exercise is to examine what are some potential vulnerabilities for California? What are some potential opportunities for California.

And, again, I keep repeating this, because this is very important, the gas market is linked, so we cannot look at California in isolation. Which, you know, we get a lot of our gas from Canada. And some of the supply in the southwest, more of it could potentially go to Mexico as they switch the fuel in their electricity fleets, as well, and also for in their industrial facilities there.

So, there's definitely -- you know, we're at the end of the line here, in California, but these factors create opportunities and vulnerabilities.

The next slide, please. So, in our reference case we've constructed this reference case and we started with 2014. And the thing that -- what you really see here is you go across these years here is that, you know, we go from 2014, 2020, to 2025. Throughout the continent, you definitely see the growth for gas demand in the power sector. You know, we were kind of of -- we were looking at these numbers at first, you sure that it's going to go up this much? Well, between 2014 and 2015, which is the 2015 is not on this slide, we saw a one trillion cubic foot increase in gas demand in the power sector. And just, you know, and it's -- and, so, that's huge. I mean, that's pretty substantial.

And these are increases that you don't -- you know, we have data going back about 30 years that you don't really see very often.

Another thing that we have to assume is the proved reserves. So, that's approximately 324 trillion cubic feet. This was the most recent EIA estimate. That is a little bit lower than the last IEPR cycle. These numbers, I have colleagues who have done this for years, who tell me that these numbers are revised a lot. The estimated resources in places like Texas, West Virginia, Pennsylvania and Louisiana decreased in that time.

We also make assumptions, in addition to the supplies, we make assumptions in terms of, for instance, how much the electricity systems throughout the country will go away from coal. So, we assume, based on an analysis of the EIA's forecasted fuel use, that 53 gigawatts of coal will be converted starting in 2015, going into 2050.

And we also incorporate, it's not on this slide, but we also incorporate renewable mandates. Because since we're looking at the whole continent, we look at what are the various renewable standards throughout North America.

So, the next slide, please. So, again, these are some additional assumptions. These haven't changed from the last report. Again, we're going to be updating the reserve total.

Since this is a simulation that includes, that tries to simulate behavior or market participants, including pipelines, suppliers, et cetera, we have to make assumptions on, you know, their rates of return. Resources, we're assuming 12.2 percent, real after tax. Pipeline investment, 8.4 percent return. And over the years this has been -- these estimates come from financial reports submitted by publicly traded companies in this area. And these are -- you know, this is where this comes from.

And, so, we also include scenarios for additional technologies that could come in. But, you know, it’s other than mandates. But at the current price levels right now, prices are really low so there’s not much discussion of that these days.

And, then, also include a factor for a one percent technology development. Because one of the things that we, going back, that you can see, basically, the difference in gas and available reserves, and the cost, and the ability to get more of them is based on technological change. So, since we’re looking at a long-term horizon, that’s going to be very important.

The next slide, please. So, the next part of this presentation is where the information, the HUB prices that are produced, what other Energy Commission models this will be used at. For an example here, the HUB prices from PG&E, City Gate, Malin, SoCalGas, and others, will be used to estimate power plant Burner Tip prices.

Another thing I forgot to mention, but now is a good time to mention it, is that we produce here annual HUB prices. And, so, in order to run this model here, the annual price needs to be converted into a monthly price, and to try to demonstrate, you know, estimate a seasonal effect based on power demand throughout the year. And using pipeline utilities tariffs, transportation cost is added on top of that.

The next slide, please. One thing that I figured out in listening to these presentations today is that I owe a bunch of groups here some data. And, so, I've listed the various models that will incorporate that HUB price data.

And one of the ones that I didn't include here is a cost of generation model that the person running that is patiently waiting for data, as well.

And again, when will that be available? The next slide, please. Staff is scheduled to have these results in mid-March. And the findings from those runs that will include the IEPR scenarios, will be ready by then, with a workshop that's already been scheduled for Tuesday, April 25th.

So, if there's any questions or comments, I will be glad to address them.

CHAIR WEISENMILLER: Yeah, I had a question and a comment, both.

MR. ORTA: Sure.

CHAIR WEISENMILLER: So, starting with the question. You know, from when I've been in Mexico, it's pretty clear that Texas is trying to really sell a lot of gas to Mexico. And I was wondering how you're factoring that into the analysis?

MR. ORTA: Well, we do include demand nodes, demand centers on the other side of the border. And to build our reference case, we used their forecasts of demand from their Ministry of Energy in Mexico. And they're looking at pretty aggressive growth. And, so, we incorporate that.

But we've also, as I mentioned earlier, there's additional pipeline infrastructure coming in from West Texas. And, so, that's being incorporated. That's already incorporated into the model, as well. So, we've -- a lot of the work we've spent so far, since there's been all these changes in the last few years, is try to play catch up with the existing infrastructure.

CHAIR WEISENMILLER: Okay. And in terms of comments, I mean, one of the things we struggled with on the last full IEPR was sort of gas prices.

MR. ORTA: Uh-hum.

CHAIR WEISENMILLER: And we had, I'm going to say, relatively low prices and the model output was relatively high prices. We tried to smooth that in a way. But, certainly, going forward it's going to be important to sort of -- you know, the shape's important.

MR. ORTA: Uh-hum.

CHAIR WEISENMILLER: And I think, as we get closer to where the step was supposed to occur, you know, not, obviously, we have that much of a step up.

But, again, I think as we go through this, it's just all of us will need to focus on the gas prices. And, certainly, commentary from any of the stakeholders on gas prices or gas would be good.

MR. ORTA: Okay, great. Thank you.

CHAIR WEISENMILLER: Okay, so thanks a lot.

MR. ORTA: Thank you.

CHAIR WEISENMILLER: We're going to go to public comment. And we'll start off with our Public Adviser. We're doing some work arounds around some of the logistical challenges.

MS. MATHEWS: Yes, this is Alana Mathews, the Public Adviser. And I have a few announcements. I believe Heather is going to announce that we're going to have a break. And, then, I'll have some instructions on how we're going to facilitate public comment.

So, do you want me to make those instructions now, or just wait for her to make her announcement?

MS. RAITT: So, basically, Alana covered it. Because we're having technical troubles today, we're going to take a little break so that we can have folks in the room be able to make comments at the tables. And Alana's going to talk about how folks on WebEx can still participate, because we won't be able to hear your voice in the room. But she's got a work around so that we can still relay any comments over WebEx.

MS. MATHEWS: Okay, thank you. So, what we are going to do is those who are joining us by WebEx, and would like to make a public comment, the Public Adviser's Office is going to read your comment for you. So, we are just asking that you e-mail that to the Public Adviser's e-mail address. And that's simply publicadviser@energy.ca.gov. And just stay on WebEx because we're going to post that for you. Again, it's publicadviser@energy.co.gov.

Once you e-mail those comments to us, we will read them for you on the record. What we are also asking is that you can use the chat function to let us know you intend to submit a comment that you want to be read. That way, we can monitor the e-mail address account and be looking for the comments that we want to have, because we don't want to miss anyone the opportunity, to have anyone speak and offer their public comment.

So, again, the e-mail is now up on WebEx. Thank you.

Okay, the Chair is making sure that everyone heard me. And I do apologize if you were just recently muted. Yu didn't miss anything. Again, we have sort of a two-step process. If you are joining us by WebEx and you would like to make a public comment, we apologize that we're having technical difficulty and are not able to allow you to make your comments, yourself. The Public Adviser's Officer will receive your comments and read them for you.

So, the two-step process is, one, we want you to use the chat function to indicate to staff you will be submitting a comment that you want read. Once you indicate that, using the chat function, please e-mail your comments to publicadviser@energy.ca.gov. And I believe that the three-minute allowance is what's usual given at the Energy Commission. So, we will do our best to make sure what you e-mail to us can be completed within the three-minute time frame.

If you have any additional questions about how this process is going to work, or you want confirmation, you can still use that e-mail address, publicadviser@energy.ca.gov. Thank you.

(Off the record at 3:46 p.m.)

(On the record at 3:52 p.m.)

CHAIR WEISENMILLER: Great, we're ready.

Please, we have one public comment. Yeah, we have one public comment in the room.

MR. ADDY: I guess this is it?

CHAIR WEISENMILLER: Yeah. Actually, so there's two mics there. One of them is on the internet and one of them is for the room.

MR. ADDY: I see.

CHAIR WEISENMILLER: So, if you can somehow speak into the room, we're set.

MR. ADDY: Both of them, all right. Okay.

Well, thank you, Commissioner. My name is McKinley Addy and I'm with Atra, the virtual integrator of low-carbon/high-efficiency technologies at scale.

I appreciate the opportunity to comment. I have a greater appreciation for the value of the IEPR process and the exercise, now that I'm no longer with the Energy Commission, and I want to comment the staff for their work.

By way of feedback, I want to highlight the importance of the CEC's IEPR work and, in particular, the transportation energy price forecasts.

In my past role as part of the team here, my colleagues and I were consumers of these fuel price forecasts for internal analytical purposes, and policy reports, and goal setting, and so on.

In my new capacity with Atra, we rely on these forecasts for investment decisions. And I was surprised, recently, when a leading industry partner, who's considering investing in California's auto tech space, highlighted the uncertainty around natural gas prices into the future as one factor in the investment decision making process.

And as I listened to Lynn Marshall's presentation, it seemed to me that changes in electricity rate structures can also be a consideration by private parties exploring investments in the transportation electrification segment.

Both observations point to the importance of CEC's transportation energy demand and fuel price forecasts, and staff's efforts to develop robust forecasts on which business decisions can be made.

We are looking to the CEC's IEPR process for competent forecasts that industry has confidence in to make investment decisions, as several industry leaders are relying on the timely availability of this information from the transportation energy demand and fuel price analysis to make some pending decisions.

The timely availability of this information will move these decisions forward. And we encourage the agency to do the best that it can. And to the extent that we can contribute to the process, we'll be happy to. Thank you.

CHAIR WEISENMILLER: Well, thanks. Thanks for being here today. I think it's really good to hear the feedback, to the staff that, indeed, their analysis really matters.

And, also, at the same time to really get it right. You know, I remember over the years, when I was doing due diligence, I always got to sign the affidavit saying, this is based on my best professional judgment. And always wondering, okay, this billion dollar project goes down the tube, what happens next? But, fortunately, I maintained my reputation. So, thanks.

MR. ADDY: Thanks so much.

CHAIR WEISENMILLER: Do we have anyone on the phone? As we said, we have this arrangement where, if you send an e-mail to the Public Adviser, it will be read into the record.

If there's none then, certainly, again, we're happy to take -- I'll go back to Heather to make the public comment -- or not the public comment, but the comments on this workshop and whatever, two weeks.

MS. RAITT: Maybe you can repeat this, as this is not going over the WebEx, but due on March 8th, I think.

CHAIR WEISENMILLER: Okay, on March 8th, written comments are due. We're certainly looking forward for written comments. As I say, we've flagged a number of issues we'd love to have more comment on from today, or feedback from anything from today would be great.

So, again, thanks. And this meeting's adjourned.

(Thereupon, the Workshop was adjourned at 3:57 p.m.)

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REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 7th day of March, 2017.

Kent Odell
CER**00548

TRANSCRIBER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were transcribed by me, a certified transcriber.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 7th day of March, 2017.

Barbara Little
Certified Transcriber
AAERT No. CET**D-520