DOCKETED

Docket Number:	15-IEPR-03
Project Title:	Electricity and Natural Gas Demand Forecast
TN #:	204949
Document Title:	Transcript of the February 26, 2015 IEPR Workshop on Electricity and Natural Gas Model Inputs
Description:	February 26, 2015 IEPR Workshop Transcript
Filer:	Laura Laurent
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	6/9/2015 9:15:21 AM
Docketed Date:	6/9/2015

COMMITTEE HEARING

BEFORE THE

ENERGY RESOURCES CONSERVATION AND DEVELOPMENT

COMMISSION OF THE STATE OF CALIFORNIA

In the matter of,	)	
	)	Docket No. 15-IEPR-03
	)	
Integrated Energy Policy Report (IEPR)	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, FEBRUARY 26, 2015

10:00 A.M.

APPEARANCES

Commissioners

Commissioner Andrew McAllister, IEPR Lead

Chair Robert Weisenmiller

Commissioner Janea Scott

CEC Staff Present

Heather Raitt, IEPR Program Manager

Ivin Rhyne, Office Manager, Supply Analysis Office

Nancy Tran, Supply Analysis Office

Chris Kavalec, Supply Analysis Office

Anise Brian, Supply Analysis Office

Akoush Katam, Supply Analysis Office

Lynn Marshall, Supply Analysis Office

Leon Braithwaite, Supply Analysis Office

Public Present

Manuel Alvarez, Southern California Edison

Tim Vonder, San Diego Gas & Electric Company

Katherine Bird, Pacific Gas & Electric Company

Sharim Chaudhury, Southern California Gas Company

Ed Martinez, Southern California Edison

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P R O C E E D I N G S

FEBRUARY 26, 2015 10:00 A.M.

COMMISSIONER MC ALLISTER: Well, thank you, everybody, thank you all for coming. This is a very auspicious occasion, the first workshop in the 2015 IEPR cycle. This is a full IEPR, so this is all the bells and whistles will apply.

And just yesterday, at the business meeting, we adopted the 2014 IEPR update which Commissioner Scott, to my right, ably led and facilitated a really broad variety of discussions. Focused on transportation but, really, you know, sort of a partial update as well, and a bunch of other topics. A very interesting and a great product that came out of that.

And I want to thank Heather, and Raquel, and all of the -- yeah, Stephanie, all of the staff drivers of that document. I mean, really, the train, as many of you know and those of you who don't, will find out, but trains definitely run on time, on the IEPR team.

And so, there's no rest for the weary, we're starting the next cycle, now.

And so, I'm Commissioner Andrew McAllister, and I actually led the 2013 IEPR and somehow agreed to do it again. But I'm very excited, actually, about kicking off here and we have a bunch of very high, important

topics to work on through the year.

And namely, the topics that are directly related to the Governor's goals that he announced in January, specifically regarding renewables and energy efficiency. I'm the lead on energy efficiency. We're going to talk a lot about that this IEPR, particularly our existing buildings and how we can do better to create the foundational tools and the informational landscape that we need to identify the best opportunities, target those, and go after them, and facilitate the market to do that. So, that's of that more to come.

Today, we're kicking off with really the basic kind of necessary foundational discussion that will inform the forecast on econ demo, on economic demographics and the broad assumptions that go -- or the various assumptions that go into the modeling and forecasting. This is a core responsibility of the Energy Commission.

To my left is Chair Weisenmiller and he knows better than probably anybody in the State the ins and the outs of the forecast, and how -- at the same time, how important it is. I mean, think -- really appreciate the Chair's dedication to getting the forecast right, and making sure that it's rigorous, and as good as it can be, and as well-informed as it can be, and as

analytically high quality that it can be.

And that's also reflect in the staff's -- that you're going to hear today, present on this issue.

And it's a really a key tool that California uses another state's look-to as a best practice. And it goes over to the other agencies, the ISO and the PUC. We'll be expecting some representation from the ISO. Not sure of the PUC today, but certainly through the course of the year we'll hear from all of the relevant agencies and probably share the dais with them on multiple occasions.

So, I wanted to give the Chair an opportunity to say a couple of works, and Commissioner Scott, and we'll get moving. So, thank you all for coming.

CHAIR WEISENMILLER: Yeah, I just want to thank everyone for coming and thank the staff for their hard work in this area.

As Commissioner McAllister said, this is one of -- what has been historically one of our premier activities. It's one where by statute other agencies are directed to give some deference to our forecast in planning. And as you go forward, it's really important that -- you know, we're trying to develop these in a collaborative fashion, particularly with the PC and the ISOs so that there's pretty much common understanding

and acceptance, but we sort of get their input. As we're moving forward, we get to a real consensus on these issues.

And, obviously, when you look at -- you know, the results come out and eventually you can print them out to how many significant digits you dare. But, essentially, anyone who's been doing this long enough knows that there are inherent uncertainties. And forecasting the future is particularly hard.

And so, looking at, first, the groundings in the assumptions are certainly key, but a lot of the outcome and trying to understand the key assumptions and then trying to understand their uncertainties are certainly part of the way to get to really realistic numbers at the end.

So, I think this is a good step. Obviously, reach out to the IEPR staff saying, okay we -- I guess Janae just had the evening off. I guess you had the scoping document, you know, before going from one IEPR to the next. But, you know, certainly appreciate your long and hard work on this project.

COMMISSIONER SCOTT: Good morning. I'm Commissioner Janea Scott and we did just finish the 2014 IEPR update, so perfect timing for today's kickoff workshop.

I'll just echo many of the things that you heard Chair Weisenmiller and Commissioner McAllister say about the importance of the assumption, the good work we're doing together with the ISO and the PUC to have a joint forecast.

And I think this year, from a transportation focus, I'm the Lead Commissioner on transportation, it's going to be really interesting to see some of the transportation electrification assumptions and different information. And we'll start with a little bit of those and we have a more in-depth workshop in a few weeks on that topic, but I'm very much looking forward to it.

COMMISSIONER MC ALLISTER: Thanks. So, Heather Raitt, take it away.

MS. RAITT: Okay. I'll just go over a few housekeeping items. I'm Heather Raitt, I'm the Program Manager for the IEPR.

In the atrium, the snack room is on the second floor. In the event that there's an emergency and we need to evacuate the building, please follow staff to Roosevelt Park, which is across the street and diagonal to the building.

Today's workshop is being broadcast through our WebEx conferencing system, so parties should be aware that you're being recorded. We'll post the audio

recording in a few days on the website and we will have a written transcript posted in about a month.

Today, we'll have presentations by staff and the opportunity for public comment at the end of the day. We're asking parties to limit their comments to three minutes during the public comment period. And we'll take comments, first, from those in the room, followed by those on WebEx, and then the phone-in-only participants.

For those in the room who would like to make comments, please fill out a blue card and go ahead and give it to me. And when it's your turn to speak, please go to the center podium and speak into the microphone.

For WebEx participants, you can use the chat function to tell our WebEx coordinator that you'd like to make a comment during the public comment period, and we'll relay your question or open your line at the appropriate time.

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

Comments are due on March 11th.

And with that, I'll turn it over to Ivin Rhyne.

MR. RHYNE: All right, good morning. My name is Ivin Rhyne. I'm the Office Manager for the Supply

Analysis Office, in the Energy Assessments Division here, at the Energy Commission.

But more relevant to today's workshop, I am acting as your MC for this first workshop in terms of the activity that's really setting the stage, as the Chair and the Commissioners have mentioned, for a lot of the analysis that's going to be going on with regard to the 2015 IEPR.

We are required under statute to look at and attempt to make reasonable assessments of what the future conditions might hold for energy throughout the State of California. And we look at energy on a number of fronts. And in doing so, we have to look at a lot of the different sectors and attempt to assess them.

So, one of the things I'm going to do today, before we get into the meat, what's going to be presented by our key staff members, our technical leads, is just set the stage for what this process is that we're going through and maybe also share some key caveats as to what it's not. We want to make sure that everyone who participates in this today understands what we are both attempting to do and not attempting to do.

So, first of all, what we're doing is developing a set of cases that we are calling the IEPR common cases. And this is an important terminology.

There are a number of models that are used here at the Energy Commission and as we go through and run these models it is often asked, after the fact, well, how does this case compare to that case? Perhaps a case run in the transportation model compared to a case that was run in our electricity demand model.

And so in doing this, in creating these common cases, we're now able to point to cases where there are the same underlying assumptions run throughout the whole process. And I'll talk about the methodology that we are using to create those cases and refine those assumptions.

And, finally, we'll talk about what some of those input assumptions are. I won't be sharing specific numbers, but I will be sharing some of the key areas of which there are shared input assumptions. And in some cases, where there might have been some conflicting assumptions, how we resolve those conflicts.

So really, the purpose here is to create three cases that translate across sectors. The energy sectors across California are complex, but they are interdependent and interrelated.

So, our transportation sector, our electricity sector and our natural gas sectors all connect to each other under various circumstances. And as policies and

infrastructure changes, and as technology changes they become more and more interconnected.

And so, by connecting the process by which we conduct our forecasting and analysis, we are creating a stronger analytical basis for policy discussions.

But one of those key caveats that we really need to start out with is that this is not an integrated modeling approach. And by integrated modeling, I'm not suggesting that the Energy Commission owns or operates a super computer that allows us to run all of these sectors simultaneously and achieve some pristine results that are exactly transferrable across all sectors.

What we in fact do are run multiple, large, complex models independently. We then show those results in a predictable way across those models, rerun those results, and then hand them back off. And that's a process that we consider a coordinated modeling process, rather than an integrated modeling process.

And just to be clear, this is not a new activity here at the Energy Commission. We started this coordination with the 2011 IEPR. We expanded that process in 2013. And, in fact, some of you may have attended a very similar workshop two years ago, where I got up and ran my mouth a little about that process then, and you may even recognize some of the graphics

that we share today. And then, we're continuing to refine that process as we go forward.

So, what are these common cases that we're talking about? Well, really just saying this is the high case or the low case isn't a specific enough terminology to be very clear as to what it is that we're talking about. High what? High prices, high demand, high heat degree days? What are we really talking about?

And so, the terminology we're using here is we're talking about energy demand. That's sort of the core metric. We have three world views that we're presenting throughout the IEPR common cases. A mid energy demand case, a high energy demand case, and a low energy demand case.

All modeling requires starter guidance. All modeling requires us to make assumptions and put those inputs in, and then run the model to generate what we think the final values are.

We are beginning by updating some recent natural gas production cost curves, and updated economic and demographic data, both of which you'll hear about in presentations today.

But really, at the beginning of this whole process we have to start with the forecast that was made

in the 2014 to 2024 process. And you'll see that, that's CED. That's the California Energy Demand, or some people might know it as the demand forecast. That refers to the electricity demand here in California. It is produced as part of the IEPR process.

We're beginning with that final demand forecast at our starting point for this process. And as you'll see, if you remember the graphic from two years ago, I know everyone has it plastered up on their wall, just like I do, you'll remember from that process. We also did a little bit here.

We begin by starting with that demand forecast and then running our Production Cost Electricity Dispatch Model, which covers the entire Western Electric Coordinating Council.

Those results of the electric -- the gas burn for electric generation are then handed off to our natural gas modeling team. We then run that. Again, that's an independent model. They run that model.

Now, that particular model covers all of North America. It includes assumptions about imports and exports of natural gas, because this is a national, and actually an international marketplace. And so, the model has to be large enough to cover all of that marketplace. And, specifically, North America is the

key segment.

Out of that model, sets of both prices and quantities of natural gas used throughout the North American region are handed off to two other models. One is the California Transportation Demand Model, of which you'll hear some about today.

And that's important because we have a growing sector in the -- a growing segment, I should say, in the transportation area of natural gas-powered vehicles.

We also hand off that natural gas -- those natural gas prices to our California Energy Demand Model, which include models that attempt to capture how for residential, industrial and commercial users of natural gas will respond to those price series.

Both of those models then hand off -- the California Transportation Demand hands off back to the North American Gas Model, and the California Energy Electricity Demand Models both hand off back to the Electricity Dispatch Model for a second pass.

So, we have a first pass which will give us preliminary results and then we do a second pass, which will give us revised results. Between those two passes we will take comments, we will hold workshops. And each modeling team will work independently to conduct those workshops. We will also work together, in an

interdependent fashion, to share those results and make sure that our processes and our assumptions remain consistent throughout.

So, what are some of the input assumptions that we're talking about? Well, there are a number that really matter. They are found in all of the models. And as you can see on the screen, those include GDP, inflation, gross State product, population changes, energy efficiency improvements, of which that's going to be a major topic in this upcoming IEPR, demand response. And things like carbon prices, and weather, and HDD and CDD. If you're not intimately familiar with modeling lingo, that's heating degree days and cooling degree days. In other words, how often is it so hot that people need to run their air conditioners or so cold that they need to run their heaters in their homes, and businesses.

All of these assumptions are foundational to a number of models. And in most cases, an increase in any of these will likely lead to increases across the board for all of the models. But that is not always the case.

In some cases, there are tradeoffs between the high and low energy demand cases. High and low demand cases, really for one sector, in some instances can come at the expense of demand in other sectors. Some

tradeoffs are necessary in defining those high and low cases.

And what we chose in order to define how we would proceed was what we called the major driver test. And just to put it briefly, if an input is a major driver to one model, but a minor driver in others, then it is the model for which it is a major driver that we use as the controlling factor. In other words, the direction of movement for the assumption is set by whichever model has it as a major driver. And when we're lucky enough to have it such that there's only one model in each case, it's a major driver.

So, really, where were there conflicting variables and then which models did we choose? Well, electricity price is an important variable. But, for example, if electricity price goes up or down, it has a larger impact on residential and commercial end-use electricity, but perhaps a smaller but inverse relationship with regard to transportation.

So, people might be less inclined to buy electricity vehicles. But, obviously, the electricity model, it would have the larger effect.

The similar results in natural gas price, so we use the natural gas model to drive -- as the controlling model.

Crude oil price and EV penetration, we follow the transportation model.

Coal price, the direction of coal price, we'd follow the electricity model and natural gas vehicle penetration, we follow the transportation model.

In each of these cases there will be further clarification, both through this workshop and other, future workshops held by each of the individual modeling teams. So, if you have questions about what those exact values are, for example what policies were included or not included, I would encourage you to participate in not only this workshop, but in future workshops for each of the teams.

And then finally, as we look at these models we need to understand what the results mean. The mid case is a reasonably expected trajectory given our best available input. And I say reasonably expected rather than given any certainty.

The Chair, I think, quite ably put it. There is a vast amount of uncertainty associated with not just the models themselves, but all of the input assumptions. So, we make our best professional judgment. We use input from processes like this to make sure that we have the widest range of thinking on these subjects, and then we make our decisions about how these inputs should be

tailored, up or down.

The high and low energy case demands are, themselves, also a reasonable range, but the last bullet I think is the key. You should not take the high and low energy demand IEPR common cases as the most extreme possible cases.

Each of us can think of price spikes or demand spikes, perhaps in different marketplaces, that would shoot above or below the high and low bands that may be presented as a result of this result. Those are obviously extreme and in most cases narrow circumstances.

These are the high and low energy demand cases are not attempting to capture those most extreme scenarios. They are, in fact, reasonable trajectory scenarios, high and low.

The next steps, as I mentioned there are going to be more workshops on a number of these processes. The next one being March 10th. We will be holding a webinar on the production cost model inputs. That is the model that we use to estimate the electricity dispatch throughout the Western United States.

And on March 19th, there will be a workshop on transportation inputs. Throughout this process we will be refining our common case assumption and inputs. And

each modeling group is going to build other scenarios.

And that's, I think, the final, important point that I want to make. The IEPR common cases, the three cases that we are building as a result of this process, do not prevent or limit any of the individual teams as they look at scenarios, or I should say they don't prevent us from looking at scenarios that ask the question what if. What if this were to occur? What if that were to become more or less, higher or lower? It allows us to explore those. But those individual scenarios, the "what if" scenarios, those are to some extent separate from these IEPR common cases.

Finally, I would encourage everyone to participate in the process that we have set up here. It is a public process. And the information necessary to participate is here and we'll have it again on later slides.

So, with that we're going to start transitioning into the presentations by each of our experts. I'm going to ask the experts, we have them here around the table. They'll be presenting from their chairs. And then, as they need me to advance slides they'll just say, you know, next slide and we'll go from there.

We will pause between each major segment and we'll open the floor to clarifying questions. If you

have more than a clarifying question, if you want to make extensive comments, I will ask you to hold those comments and submit the blue cards, as Heather mentioned earlier.

So, first up we have Nancy Tran, who will be presenting on the economic and demographic assumptions. And we'll pull up the presentation.

And Nancy, the floor is yours.

MS. TRAN: Thank you. Good morning, my name is Nancy Tran and I am from the Demand Analysis Office. Today I'll be discussing California's economic and demographic outlook.

We need to define the economic and demographic assumptions for energy demand forecast. We'd also like to provide a general economic overview because the economy is important in other analytical work within the Commission.

More specifically, the purpose of this presentation will be to give an overview of the economy and demographics.

Some background information that is considered in the demand forecast. We're going to summarize comments from experts on the post-recession landscape. And our experts are our data vendors, which is Moody's Analytics, IHS Global Insights. We also use the

California Department of Finance. And we have economic academic experts that we use from UCLA's Anderson Forecast, Jeffrey Michaels, of the University of the Pacific, and Dowell Myers of USC, who is a demographic expert.

And lastly, we're going to describe major uncertainties over the next ten years.

This is the agenda for today's presentation. California's energy policy has made significant progress in reducing energy consumption through efficiency and other demand-related efforts.

However, economic and demographic patterns remain the most significant patterns -- the most significant factors in determining energy consumption.

For example, this graph clearly shows the impact of the economy on electricity consumption by plotting statewide employment alongside consumption over the last couple of decades.

This also shows the impact of the recession on energy demand. As you can see, the arrow is pointed down at 1990, 2002 and 2008.

The effects of the great recession are particularly apparent as both employment and consumption take a large dip beginning in 2008 and only a little over six years are they approaching pre-recession

levels.

Turning to the forecast for just a moment, here are key economic drivers that we use in our forecast. These are inputted into our forecasting models.

Okay, now I want to start by looking back at the recession. During the recession California experienced downturns everywhere. Over one million Californians lost their jobs. And as we all know, there was a huge housing bust, with home values declining on average 45 percent throughout California.

California also experienced increased mortgage defaults, foreclosures, short sales, and increased income inequality.

This slide shows the severity of the situation. As you can see, in 2009 California had dropped by six percent. California's annual employment growth has returned to pre-recession levels at an annual rate of three percent in 2012 to 2013.

This also shows that after 2011, California is recovering faster than the nation. And we don't expect another recession.

This graph shows, again, that California was hit harder than the nation. To look at this another way, this slide shows the unemployment rate. California was hit harder with 12 percent unemployment. The rest of

the nation was hit with a little less than 10 percent in 2010. California -- well, as you can see, California is on the road to recovery at 7.6 percent unemployment rate in 2014.

Recessions are measured in change by GDP. And sometimes there is a delay in reflection of the unemployment rate.

The next slide. Housing is starting to rebound for single and multi-family units. Economists have stated that this trend is going to continue. Single-family housing will continue to grow a little bit faster than multi-family units.

Now, we're going to move on to California's demographics. This slide shows historical population in California. Population growth is slightly slowing down since 20 to 30 years ago. For example, in this last year population was less than one percent versus 1.8 percent average annual growth from 1980 to 2000.

The next slide. And although population trends have slowed, population is estimated to grow one percent over the next 25 years, and this is according to the Department of Finance.

Now, we're going to go into two important aspects of population growth, which are birth rates and migration. Our experts have stated the following

drivers are associated with population growth. And at the very last bullet, death rates are minor because death rates have little variability. So, effectively, they're not able to raise growth.

An important component of population is migration. According to demographic experts, net migration will continue to be positive due to international immigration. California's inland population growth is expected to be faster than the coastal region. In fact, this has been occurring for the last few years. And coastal regions still have a higher population than the inland regions.

Population growth is projected to be less than six percent for coastal regions and 15 to 16 percent in the inland regions. And this is from 2014 to 2025.

Now, an important demographic characteristic we like to pay attention to are housing trends. These trends will be different and in large part by the patterns of baby boomers on the millennial. There aren't expected changes in the millennial. However, with expected retirees in the next few years, baby boomers will increase.

Millennial tends to be greener in their choices, with more innovative green technologies for easier energy and lifestyle efficiencies. This means

programmable technology through their cell phones, being able to program their thermostats, their lights, their home security system. And this is according to the National Association of Homebuilders, as they assess the demands and needs of different generations.

Millennials, as opposed to baby boomers, like to live in cities versus the suburbs. So, this could mean a reversal in population growth trends from coastal to inland regions.

Going back to the economy, I'm going to talk about short-term, mid-term, long-term growth. And a key driver is the rebound of construction in California. A key driver is -- this table shows residential and nonresidential permits. And as you can see, there's a fairly large increase in numbers from 2011 to 2014.

Other short-term economic drivers include low mortgage and foreclosure rates, low oil and gasoline prices. And as for the government recovery, this is specific to local and state governments, where government jobs can increase. And federally, more defense spending benefits areas such as San Diego.

Mid-term growth will come from a boost in a tech and housing sector. Our experts expect growth, so gross state product to grow at around three percent per year.

Turning to long-term growth, the most recent

economic forecasts have downgraded their assumptions on potential growth due to the long-term damage on the economy that was inflicted by the most recent recession. And it is expected to be greater than initially anticipated. The scarring effect refers to decreased entrepreneurship, reduced household formations, damaged credit from borrowing, rate, mortgage lending standards, minimal labor force participation, and reduced investing in capital stock.

However, long-term growth is expected to keep pace with the nation. Because of the high-tech industry and investments in the infrastructure, overall the next ten years will be about two percent growth compared to over two and a half percent 20 years ago.

Now, we're going to summarize the economic and demographics for four major regions in California. We're going to start with Southern California's Los Angeles Region. Los Angeles is among the largest and most diverse of the regions. The unemployment rate has decreased to less than eight percent. The expansion of technology firms is occurring in Los Angeles and is generated competition for firms in Silicon Valley and the San Francisco Bay Area.

Potential shipping changes caused by the widening project of the Panama Canal will affect the Los

Angeles Region because they have the two largest port sin that region, the Los Angeles Port and the Long Beach Port. It is expected to be less container traffic. However, the magnitude of drop off is uncertain. Also, the Panama Canal will allow larger tankers to transit the canal, possibly reducing the cost of moving oil from the U.S. Gulf Coast to the West Coast. But this also depends on the level of canal fees that will occur.

Moving onward to the Sacramento Region. The Sacramento Region is a healthcare hub and it's benefitting from new hiring and investments in the industry, thanks to the Affordable Care Act. And as well as the demand for healthcare services as our baby boomers age, and our millennials begin to create families of their own. The unemployment rate is less than seven percent.

We expanded the Sacramento Region to include Kern County. Kern County is home to the five most productive petroleum fields in California. Nearly seven percent of jobs in Bakersfield, alone, are linked to petroleum. And that's the highest percentage among all the largest metropolitan statistical areas within the nation.

Most of us are benefitting from the low prices at the pump. However, places like Kern County, who

benefit from the oil industry, are now suffering and the County recently declared a fiscal emergency. Petroleum companies pay millions of dollars in property taxes to the county, which goes towards public safety and schools. When the price of the oil drops, the value of that land goes down, so fewer tax dollars are going to the county. And for the upcoming fiscal year, that's about $61 million that Kern County will lose because of these low oil prices.

It's unknown at this time what the Kern County Board of Supervisors are going to do to make up the budget shortfall, but this is becoming a ripple effect because the drilling companies are laying off employees because their profits are dwindling.

However, this might fix itself soon because prices of oil may go up. This issue will be discussed in our new workshop, on March 19th.

The next slide. Moving back down south, to the San Diego Region, the unemployment rate is currently less than six percent. Growth is expected in biotechnology, defense, manufacturing. San Diego is one of California's most concentrated sectors of clean tech employment, with more than 850 companies.

These companies represent 10 percent of all total green jobs in California, 13 percent of renewable

energy jobs in the State, and 11 percent of energy efficiency and green building jobs in the State.

And lastly, we'll head back up north to the San Francisco Region. This region has suffered less during the recession and recovered at a much quicker place. They're unemployment rate is about four percent. The tech boom has caused strong wage growth and this sector continues to be the main driver in this region's success as tech firms have the ability to integrate their products into infrastructures of business in all industries.

Housing shortages will lead to faster house price appreciation and a need for construction growth.

The next slide. There are many predictions about the California economy. Experts predict positive growth for California. However, there are economic uncertainties.

Well, first, this is going to be our fourth driest year on record and if the drought continues, it will adversely affect the agriculture sector with higher food prices and a loss of income.

As gasoline and oil prices continue to be low, it will fuel the economy, except for Kern County. However, we may return to higher prices. Again, in your next workshop on March 19th, we'll discuss this.

For the impact of baby boomers and millennials, the uncertainty here is the future of living pattern. And the scarring effect, we're not sure how long the scarring effect will last and how severe it is. And, lastly, whether migration patterns to inland regions will continue.

So, in conclusion, we're recovering faster than most states. Growth is fueled by high tech. Population is growing at a slower rate.

You can define traditional as minus new electrification. Our claim is that traditional electricity usage will grow at a lower rate than in the past because of the scarring effect on long-term growth and the low population growth, as well as efficiency efforts. The ultimate amount of growth will be determined by the degree of electrification, such as electric vehicles in ports, and trains.

That concludes my presentation. Are there any questions?

COMMISSIONER MC ALLISTER: No, that's really good. I guess I was wondering about the sort of green job numbers that you had in, let's say in the San Diego Region, I guess, and sort of what the source of some of that information was?

MS. TRAN: It's strictly from San Diego. It's a

government -- it's their local government business economic site.

COMMISSIONER MC ALLISTER: Okay, so that's like (indiscernible) -- yeah, okay. Great, thanks.

CHAIR WEISENMILLER: I guess the thing I wanted to understand is more the inland/coastal dichotomy. And it seemed like the inland was the most -- more heavily hit than the coast by the recession. And at the same time, certainly, we have growth seems to be more inland than coastal, in terms of what we're looking for. So, just trying to understand whether that's a lower base or just the natural demographics of housing forcing people inland.

MR. KAVALEC: Yeah, so there are sort of two things going on in the inland areas -- two things going on in the inland areas. There's more growth because of lower cost of living and lower housing prices. But those areas are also very -- some of them are very depressed, as well. Out in the desert, the lower San Joaquin Valley, the Northern Valley above Sacramento.

And I guess I'm not sure if I'm answering your question, but part of our job is, you know, in our forecast is to accurately reflect that when we produce our climate zone forecasts. What will be the net effect of more population growth, along with a more depressed

economy in those areas?

CHAIR WEISENMILLER: Yeah, precisely. I think that's precisely what our job is. I was just trying to -- thinking about it, you know, I remember I went and met with all the CMUA members at one state and they just answered around the room on how they were doing.

And except in San Francisco, which felt overrun by construction everywhere, everyone else was like the economy's down, sales are down, and it was really a pretty bad story. That was probably more like two -- it was a couple years ago. And, you know, last time in San Bernardino County, again, they were just hammering me, the Inland Empire, in just how bad the economy was there.

And so, they certainly felt the recession. But at the same time, certainly, our projections are for more growth in those areas. But just as I go out in the field that's the message I'm getting. So, just again trying to put things more in perspective or make sure -- I mean, obviously, you're going to use the projections of the various entities and pull them together. I just am trying to reconcile that sort of in-the-field people saying, oh, my God, we were hammered and we're hurting, with sort of the growth projections.

MR. KAVALEC: Yeah, so there has been trend

toward migration inland for the last 10, 15 years. However, when the recession hit, the inland areas got hit more severely and it lasted longer. And that migration into the inland areas slowed down. It was still -- growth was still higher than other coastal regions, but it slowed down significantly.

Now, with the recovery and as I said, the inland areas took a longer period of time to start recovering, at least according to our experts, now that migration pattern, higher growth inland versus the coast, will pick up again.

CHAIR WEISENMILLER: Okay. Also, I guess UC Davis has done some studies on the impacts of the drought on agricultural. I'm just trying to make sure we tie it into those.

MR. KAVALEC: Yeah, as I understand it, they looked at the impact of the drought in 2014 and found that we had lost around 17,000 jobs related to the agricultural sector, and output was down by a couple billion dollars.

So, in terms of reflecting that in the forecast that's tough because, you know, we could have the rainiest year on record next year, you know. So, we typically assume an average rainfall.

CHAIR WEISENMILLER: Yeah.

MR. KAVALEC: So, but I think the more critical issue is related to energy on the supply side, anyway, when it comes to the drought, and renewables, and so on.

CHAIR WEISENMILLER: Well, obviously, we take some attempts to take into account climate change impacts long term. But you're right, presuming that, hopefully, the drought is more a short-term phenomenon than --

MR. KAVALEC: Let's hope so, yeah.

CHAIR WEISENMILLER: Yeah, hopefully. I guess the other thing, one of the big changes last time was we much -- we found it was really a substantially lower population forecast. I just wanted to see how the numbers are holding up, whether we're matching that or not?

MR. KAVALEC: So, you mean -- yeah, so, really, all three of our sources for population have reduced their expectations of population growth in California in the future.

CHAIR WEISENMILLER: Uh-hum.

MR. KAVALEC: So, we'll have a high, mid and a low scenario. But relative to previous forecasts, all those scenarios are based on lower population growth for, you know, the aging of the population, less domestic migration in California. Although,

international migration is expected to continue.

COMMISSIONER MC ALLISTER: Can you talk about, so you have the Moody's and IHC, the sources that we have for some of our data -- well, backing up, one of the things we're trying to accomplish going forward, you know, in this forecast and in future ones is get a more granular appreciation of all of this.

And could you talk about the level of geographic specificity that this data is available at and how that, you know, does or doesn't facilitate kind of getting to more localized analysis?

MR. KAVALEC: Yeah, we had some discussions with them, along with our academic expert panel, on the level of disaggregation that's reasonable in terms of economic and demographic projections. And Moody's and Global Insight both insist that when you're at the county level you're already pushing it.

Below the county level, like it's a census tract level or something, Moody's and Global Insight don't even attempt to produce forecasts at that level. They don't think they can produce anything credible.

So, really, for us the unit, the most disaggregated unit in our forecast is at the county level.

There are other methodologies. For example,

through REMY (phonetic), that attempt to go down into census tract levels, and we've talked to them a little bit. But they're basically just providing a framework for you to do that. You have to fill in all the answers in terms of where the developments are going to be, where the big industrial customers are going to move, and so on.

COMMISSIONER MC ALLISTER: So, I guess, I'll say that there are counties that lend themselves to that kind of analysis more than others. I mean, you're going to have a lot more population in an L.A. County than in, you know, a San Bernardino or something.

MR. KAVALEC: Yeah.

COMMISSIONER MC ALLISTER: Yeah, or Tulare County or something. And that's where the population is and that's where much of the infrastructure is. And so, you know, I'm wondering kind of how going forward we might be able to work with some of the local stakeholders, the COGS (phonetic), the folks who actually do the planning in those areas to maybe push forward on fronts where it might make sense. And I'm not sort of projecting what those might be but, you know, work with the counties or the NPOs to try to project with a little more granularity as we go forward.

MR. KAVALEC: Yeah, I think that's -- I mean, if

we're going to go beyond the county level, that's our next step, we have to take advantage of whatever projections are provided by the local city governments. And, of course, we have to talk with the -- get whatever information we can, energy-wise, from the utilities since they're experts on their own service territories.

COMMISSIONER MC ALLISTER: I mean that's exactly, that's kind of where I wanted to get is that, you know, it's not just about the econ demo, but it's also about the tending on the energy side, specifically. And I'm thinking more for the energy efficiency, but it's really relevant across the board, I think.

MR. KAVALEC: Yeah, and I always say that in our forecasts there are two types of forecasts. There's what I call a fundamental forecast, which is based on equations, and economic, and demographic drivers, and so on. And then there are sort of shifting, or disaggregating that forecast to more local levels.

And to me, it seems that this is where the split is going to occur between a fundamental forecast, at the county level and higher, and a more disaggregate forecast is going to have to be more a shearing off of an existing forecast, rather than a fundamental forecast.

COMMISSIONER MC ALLISTER: I agree with that. I

think you're going to have -- you're going to head to the time to a new methodology, at some point, when you get down to the lower scale.

MR. KAVALEC: Right.

COMMISSIONER MC ALLISTER: And that's appropriate. I think that's probably -- that's practice and that methodology discussion is one that I think over the coming cycles, starting now, but developing it across the agencies so that it's most relevant for us is really a worthwhile thing to do. You know, within reason and resources.

MR. KAVALEC: Yes.

Okay, so we're going to move to the next presentation in this section, which coincidentally will be presented by Chris Kavalec, with the Demand Analysis Office. He'll be speaking on the economic scenarios and projections for key economic and demographic indicators.

So, Chris, all yours.

MR. KAVALEC: I actually have two consecutive presentations here, so I've combined them into one package.

And I'm going to talk a little bit about the timeline for the demand forecast, the idea of demand scenarios, and then turn to the economic, demographic common cases, as Ivin has defined them, that are going

to drive our demand scenarios. And then talk about our efficiency and demand response assumptions. And then we will have other presentations that support our demand forecast, as well as other work, distributed generation, electrification, and rates, both electricity and natural gas rates.

Okay, our next milestone coming up here is data that we receive from the load-serving entities that comes in on -- or that's due on April 15th. And we get data from them on efficiency, demand response, distributed generation, historic sales and peak demand. And they also produce a forecast for the next ten years, for these demand forms.

And part of our work in the preliminary forecast is to compare our forecast with what the utilities are predicting and attempt to resolve any differences.

So, our workshop where that topic will be discussed, our forecast versus the utility forecasts, will be at the beginning of June. We'll then have, after incorporating comments and including some other work, which I'll get into later, we will have a revised forecast workshop in November and December of this year.

In the past, we've had a revised forecast around the October timeframe. However, we would like to incorporate in the revised forecast the summer loads

that we get from Cal-ISO, which we don't get until October. So, we could out a revised forecast like October, but everybody's first comment is going to be why don't you have the summer loads incorporated in.

COMMISSIONER MC ALLISTER: We talked a little bit, or talked with Heather kind of informally about, okay, the statute says we're supposed to get the IEPR out in the calendar year, and all that, but in practice, as you're pointing out, there's just lots of tweaking to do. If we want to do it right, we have to wait for that data in October.

So, I wonder, maybe the Chair can comment on this, but sort of adjusting the timeline to sort of not put the Lead Commissioner in a bind. I mean, the Legislature's wanting the thing out, you know, because we're trying to do it the best way we can, and it's sort of the timeline is dictated by events in a way so --

CHAIR WEISENMILLER: Yeah, I think the reality is, although again, (inaudible) -- will probably jump up and strangle me. Is that at one point I was working, actually, for a utility, trying to figure out how the PUC was doing on responding to the various legislative directions in terms of timings, and it was all fairly bad was the bottom line.

COMMISSIONER MC ALLISTER: It's not like the

Legislature's really complaining that much.

CHAIR WEISENMILLER: Yeah, so I haven't gotten why are we getting this report in February, instead of December, so I could it read it over the holidays, you know. So, yeah, I think we're just going to continue --

COMMISSIONER MC ALLISTER: It would be nice to be in sort of full compliance, if possible, you know, but not a huge deal.

MR. KAVALEC: Yeah, our plan is not to move back the adoption, itself, it was just to move -- reduce the time between the revised forecast and the final forecast and adoption.

Okay, next. Okay, defining our demand scenarios and I refer to the baseline here, we have our forecast broken down into two components. The main baseline demand forecast and then an additional piece that includes additional achievable energy efficiency. And together, the baseline and the AAEE savings give us a managed forecast.

So, I'm sticking here with baseline demand scenarios. As usual, we will have three cases, a high, a mid and a low. Where in the high case we have higher economic and demographic growth, lower rates, lower self-generation impacts, which means higher sales. Climate change impacts, we get temperature scenarios

produced for us by the Scripps Institute of Oceanography and they provide multiple scenarios, 12 to 15. And we typically choose one of the higher scenarios, in terms of temperature change, to use in the high demand case. And in the mid demand case we pick a scenario from Scripps right around in the middle.

Low electrification meaning, basically, more electric vehicles in the high demand case.

And the opposite in the low demand case, and then our mid, we have assumptions in between the two and that's our more likely case, I guess we call it. And that's typically the forecast that's used in resource planning.

Okay, so our economic and demographic common cases that will be used in our demand forecast, along with other analysis.

Three takeaways, from Nancy's presentation earlier, that are important to the forecast. We are aware of the scarring effect and the impact it's had on long-term growth. However, there's very few experts now talking about a second recession. And that's important in defining our scenarios.

The combination of housing recovery, and increase in new construction of housing, plus the aging of baby boomers, and more and more empty nesters, and

the characteristics of millennials to form smaller households, this is likely to reduce average persons per household. Which all else equal means more households, and the household is the unit which we use to drive our residential forecast. And I'll talk about the implications of that in a minute.

And then our migration patterns within the State, it's indeed we're resuming higher population growth within the State. Well, that makes our climate zone analysis important, looking at the inland areas versus the coastal areas, particularly when we're talking about peak impacts.

Next. So, we have a total of nine scenarios available to us from Moody's and Global Insight. I didn't provide a full description of each one. But as an example, in the higher demand cases you have assumptions like a faster recovery in Europe, oil prices staying lower longer.

And then the opposite in the lower cases, oil prices begin to go back up more quickly, and the EU continues with its economic issues without any improvement.

So, of these eight cases, I guess it's eight or nine cases, I used a very scientific method to develop a range by choosing the highest and then the lowest in

terms of growth among these different scenarios. And then our mid case is our Moody's -- what Moody's refers to as their baseline or most likely case.

Next, so a quick look at some of the key economic variables that drive our forecast, as well as other analyses.

First, personal income. We have the three scenarios, high, mid and low in the green, dark blue, and purple, respectively, for our new forecast.

And the mid case scenario that we used in our last forecast, the 2014 update, is shown in red. And you can see here, hopefully, that the personal income is almost identical between our new proposed economic scenario and what we used in 2014.

Next, roughly the same case for statewide employment. Again, the red curve is basically on top of the dark blue. Those are the two mid cases, the old and the new. A little bit higher growth in employment, a little bit more optimism about employment growth versus the last forecast. But overall, very little difference.

Manufacturing output, you'll see the two, the mid and the low cases crowded together there. And this is typical of Moody's, which we use for the mid and the low case for manufacturing output. They're manufacturing output predictions are not very responsive

to their definition of scenarios, not very responsive to changes in GDP, and so on. So you have, as usual, the mid very close to the low, and the mid as well very close to what we used in our forecast update in 2014.

And Global Insights, also as usual, is much more optimistic about manufacturing production in California than is Moody's.

I want to take a moment to talk about number of households because this is important to the forecaster. The difference we're showing here is important to the forecast. Typically, in the past, we had been fairly conservative when it comes to projecting changes in the average size of households. The more, the bigger drop off you have in average household size, all else equal, the more households you're going to have.

And so, we've been conservative because we haven't seen much of a pattern change in the historical data. It's remained relatively flat. However, we now have DOF, Moody's and Global Insight all saying there's going to be a reduction in average household size, meaning more households.

And as Nancy discussed, there are good reasons to believe this is going to happen. We have more and more empty nesters with, potentially, smaller homes, an increase in new construction, and millennials who tend

to form smaller households. So, overall there's reason to believe we're going to have a drop off in average persons per household.

So, the results of all this, if you look at the red line there at the bottom, this was our mid case assumption for number of households in our previous forecast. And as you see, it coincides with our new, proposed low case for number of households. That's because we're assuming a drop off in all three of our scenarios in persons per household, which increases the number of households.

So, this is what I'm proposing, but I'd like to hear from the utilities, what their own expectations are in terms of household size, assuming you use a household size or number of households in your own forecasts. We'd like to hear what you think. Not necessarily today, but in comments, written comments afterwards. Because as I said, this is an important component of our forecast and we have two mid cases now, the previous versus the new, that differ by a couple hundred thousand households in the forecast period.

COMMISSIONER MC ALLISTER: Is that coming from your data sources, Moody's, et cetera?

MR. KAVALEC: Yeah.

COMMISSIONER MC ALLISTER: So, projection of

number of households.

MR. KAVALEC: Yeah, so the -- actually, I should go back. Could you go back three slides? Yeah, right there.

So, I defined in general what our economic cases were going to be. For population and households it's slightly different. I forgot to go over this earlier. We like to include a scenario from the Department of Finance because they're the experts in California demographics.

COMMISSIONER MC ALLISTER: Right.

MR. KAVALEC: So, in this case our low demand case, or low growth case comes from DOF. Moody's base case gives us our mid demand for both population and households. And then in high demand we have Global Insight.

And as I said, all three of these, the two vendors and DOF, are predicting reduction in average household size over the next ten years. So, that's going into -- I propose that as going into our forecasts for our three scenarios.

COMMISSIONER MC ALLISTER: Okay, great. So, we're talking households but, essentially, you know, population I guess is there. Equivalent for information on, you know, the other building sectors, commercial,

and kind of square footage type stuff, do they do any of that as part of the data they provide to us?

MR. KAVALEC: They don't. We get our floor space data from Dodge.

COMMISSIONER MC ALLISTER: Oh, okay.

MR. KAVALEC: Okay, and that's a whole other story.

COMMISSIONER MC ALLISTER: Yeah, I know, that's a different -- it's kind of a parallel discussion, so not exactly this, but putting all the pieces together is kind of important. Thanks.

MR. KAVALEC: Okay, up to slide 15 here. Well, I guess I'll stop there, and before the next part of my presentation and ask for questions or comments.

COMMISSIONER MC ALLISTER: No, I'm good. Chair?

CHAIR WEISENMILLER: Yeah. No, I was going to say the one that's just been mentioned, just on the demographics, just the statistic one. Actually, when the (inaudible) -- is that from 2007 to now, so our net zero on immigration from Mexico into the U.S. Obviously, if you go back to .201, or whatever, up to that period of time it's much higher.

MR. KAVALEC: Right, which is one of the reasons why persons per household was remaining flat rather than dropping, as the DOF has been predicting.

CHAIR WEISENMILLER: Yeah.

MR. KAVALEC: Okay, efficiency and demand response, the next slide. First, efficiency. As usual, we have new initiatives to account for within our forecast. In this case, we have new appliance standards which are expected to be adopted in May, I understand.

Our practice is to wait until standards have been finalized and adopted before we include them in the forecast. So that means in May, that means that new appliance standards will appear in our revised forecast, but not in our preliminary forecast.

COMMISSIONER MC ALLISTER: So, by that you mean, just to be perfectly clear, that it basically goes into the base case? It sort of moves from AAEE over into just the --

MR. KAVALEC: That's right. What we used to call "committed", but we don't use that term anymore.

COMMISSIONER MC ALLISTER: Yeah, exactly. Go where, yeah, we all are going to get committed.

MR. KAVALEC: We have new IOU programs for 2015. And then we have 2014 and 2015 POU programs to account for. And we will have, by the time of our revised forecast, new estimates for additional achievable energy efficiency coming from new IOU potential study ongoing at the CPUC.

CHAIR WEISENMILLER: Well, hopefully, we'll have EMV also. I'm tired of getting new, potential studies, but no EMV.

MR. KAVALEC: Yeah, as I understand it --

COMMISSIONER MC ALLISTER: Who are you looking at?

MR. KAVALEC: -- the EM&V, the '10 to '12 study is going to be built into the new, potential study. And it's also, the '10 to '12 EM&V results were used to adjust the 2015 reported savings for the IOU programs, as I understand it.

CHAIR WEISENMILLER: Right.

COMMISSIONER MC ALLISTER: Yeah.

MR. KAVALEC: Yeah, but there's always a long lag between the --

CHAIR WEISENMILLER: I'm hoping you're doing the independent assessment of that?

MR. KAVALEC: Or course.

COMMISSIONER MC ALLISTER: And where do the POUs and IOUs sort of compare along these lines?

MR. KAVALEC: Well --

COMMISSIONER MC ALLISTER: Not in terms of their results, but sort of just where they fit into the base forecast versus AAEE, that kind of thing?

MR. KAVALEC: The POUs typically only fund one

year ahead, so we would have something for 2015 as, you know, finalized, adopted, whatever you want to call it, program savings.

The IOUs operate in three-year cycles, but they have -- because, just because of different conflicts and other proceedings they've done 2013-2014 as one lump, and now 2015. But they're typically practice is to go, you know, at least three years ahead, and that may increase to seven to ten years.

COMMISSIONER MC ALLISTER: Yeah, I was going to ask how are you proposing to deal with the rolling portfolio concept in terms of where you stick the anticipated savings?

MR. KAVALEC: Yeah, the way I think of it is there -- I think there will be a component of that which we could call, you know, approved, and included in the committed forecast once that all gets hashed out.

But I think there will continue to be programs that won't yet be defined within the rolling portfolios that would have to stay as part of the future potential and, therefore, AAEE savings.

COMMISSIONER MC ALLISTER: So, where would that discussion happen between -- is that in the DOG (phonetic) -- or is that in -- sort of where does that discussion between PUC staff -- so get a sense for the

forecast of what's likely to occur in terms of their program structure.

MR. KAVALEC: Yeah, these are typically, well, in the last cycle and in this cycle we've -- the potential study participants, Navigant and CPUC, have been reporting and discussing the findings for the potential study in DOG meetings. And that's going to continue in this cycle, too. And we've had a couple meetings, already, for the new, potential study.

COMMISSIONER MC ALLISTER: Okay, thanks.

MR. KAVALEC: So, our estimates for additional achievable energy efficiency will come as before for the IOUs from the potential study.

We are going to attempt to do something similar for POUs in this cycle, which we didn't do last time, taking advantage of the demand form data they submit, whatever EM&V studies are available for the POUs, and AB 2021 reports, and so on.

Hopefully, with all those sources and more discussions with the POUs, we can come up with something credible in terms of AAEE savings.

A little bit more about the potential study. They incorporated their expectations after discussions with us, future building and appliance standards, as well as federal standards. And, of course, future

incentive and behavioral program savings out ten years.

And then we have a slew of programs, policies we're interested in, and I've listed here some. But our plan is to work with Navigant and the CPUC to incorporate these policies into the potential study through one or more scenarios to reflect potential in an AB 758 world or a PACE world.

However, the potential study is being done in two stages. State one, which is going on now, and state two which will be later in the year, and into next year. And the reason they're doing it like this is they needed to produce something quickly, both for developing the 2016 goals at the CPUC, and providing something in our forecast for 2015.

So, this is being done in a rush, so it's basically a refresh of what they did in 2013. The real analysis for things like zero net energy, and AB 758, is not going to happen until stage two. So, that means it won't be part of the 2015 IEPR forecast.

It's conceivable, it's reasonable to expect that we could include the second stage, the results from the second stage in our forecast update next year.

COMMISSIONER MC ALLISTER: So, you're talking just not having it even be in the AAEE?

MR. KAVALEC: Well, when you introduce a

specific policy like, say, Proposition 39.

COMMISSIONER MC ALLISTER: Right.

MR. KAVALEC: You've got to do some additional analysis in terms of targeting, you know, the building types you want to target, gathering more data, developing specific measures. So there will be -- in the potential study they do sort of a broad brush, so there will be savings coming from schools and other building types that would, in real life, be part of what Proposition 39 provides. But they're not addressing it specifically.

COMMISSIONER MC ALLISTER: I guess I would encourage us -- so, these are pretty different, zero net energy and OEO we're going to try to do. So, that could elicit some general sense of what the results of that are likely to be, you know, assuming some level of success with that. I mean, we have a clear policy mandate across the agencies, or policy goal across the agencies, so that's a very specific discussion.

You know, AB 758 is more of a portfolio of initiatives so not really, in and of itself, evaluatable in terms of its expected impact. It really would be measure by measure or, you know, initiative by initiative, but one of those initiatives, you know, such as Prop. 39.

And then we'll have -- well, we already have a pretty large group of approved implementation plans, with specifics in there, that we have in this building already. So, that -- you know, those won't be evaluated savings with the NMB (phonetic) reports this year, obviously, because they're just now -- the shovels are just coming out, really, on those projects.

But we do have, I think, have a good sense of what the schools are going to do in terms of projects. So, how can we kind of parlay that into some sense going forward?

CHAIR WEISENMILLER: The other question we have is that some of it we're getting into attribution questions.

COMMISSIONER MC ALLISTER: Yeah.

CHAIR WEISENMILLER: And particularly, in the additional savings area you could easily see a situation where we'd be saying, well, this is going to happen because of Prop. 39, and the utilities are saying it's going to happen because of their --

COMMISSIONER MC ALLISTER: Incentive programs.

CHAIR WEISENMILLER: -- incentive programs, and God knows what else.

COMMISSIONER MC ALLISTER: Yeah.

CHAIR WEISENMILLER: Somehow, there's probably a

list of things that happen which, you know, may be attributable to any number of things. But, certainly, in each of those programs they may want to attribute everything to them. But we have to worry about double counting there.

I was also a little bit curious, because the first line is about future building standards, but when we get to zero net energy, I remember you and I both scratching our head trying to figure out what in the hell the building standards were going to be in 2023, or whenever. When, you know, we've gone to zero net energy for residential it's like, okay, well, what's the encore for the next two standards after that which, somehow, Navigant is projecting. You know, sort of what's the difference between the two.

COMMISSIONER MC ALLISTER: Yeah, so just following up on the Prop. 39 issue. I mean, I think, yeah, there will be many -- there will be a number of projects, hard to say how many, that actually get done and save energy, but have zero participation from the portfolio of utilities.

So, those are real savings that happen and upgrades that happen but aren't -- you know, they impact demand, but aren't necessarily within the wedge that has to be with programs.

MR. KAVALEC: Right.

COMMISSIONER MC ALLISTER: So, I think we probably ought to think that through.

CHAIR WEISENMILLER: Yeah, but isn't some of this the up-to-code-question? So, if the utility programs aren't funding, getting the savings to code --

COMMISSIONER MC ALLISTER: Yeah, to some extent. To some extent.

CHAIR WEISENMILLER: To some extent. And again, as we're trying to parse this out -- you know, it's interesting to make a list here, but there's nothing to discuss on that issue, on what that might mean.

COMMISSIONER MC ALLISTER: Yeah, that's right. But I guess there's some sense that there are many projects that may be just to code, that the schools are getting funding to do that are producing savings. And, you know, the big question is would they have happened without the Prop. 39 funds. And I think there's -- you know, I'd like to dig into that issue a little bit to see what we think, how we think. For the moment, how we think they're going to influence demand.

I don't actually -- for our purposes here, I don't actually care about the attribution per se, but really just how they impact demand. And then we know they will, so we kind of need to think about that, I

think.

MR. KAVALEC: Yeah, we can definitely have more internal discussions on this.

COMMISSIONER MC ALLISTER: Yeah.

MR. KAVALEC: And develop our own estimates. However, you know, this is the natural platform to account for things like Proposition 39. Because, as you said, there's going to be overlap with other programs.

COMMISSIONER MC ALLISTER: Right.

MR. KAVALEC: So, it's good to have one platform to do everything so you can account for any, you know, overlap between different types of initiatives.

CHAIR WEISENMILLER: No, I think having -- my big concern, as I said, was making sure, A, we're accounting for everything, but we're not double counting for everything.

MR. KAVALEC: Right.

CHAIR WEISENMILLER: And so, you know, obviously I would tend to say the PUC EMV programs, the attribution has really been phenomenally difficult. And I'm just saying let's not repeat making attribution something that gets in the way of getting accurate numbers out.

MR. KAVALEC: Yeah, exactly.

CHAIR WEISENMILLER: Either under or over

accounting.

COMMISSIONER MC ALLISTER: Yeah, we don't have to make the attribution problem our problem in terms of the forecasts.

CHAIR WEISENMILLER: Right, that's all I'm saying.

COMMISSIONER MC ALLISTER: The PUC will have to work it out for them to figure that out. But that's really a like ratepayer money issue more than an overall demand issue. Yeah, thanks.

CHAIR WEISENMILLER: Again, as you know, there's been this big evolving issue of to the extent the PUC incentives are tied to going beyond curve code. Then we're left with how do we achieve the savings up to code?

COMMISSIONER MC ALLISTER: Yeah, so really what we're talking about here is a code compliance penetration problem. I mean, in large part, anyway. So, what is our -- for existing buildings, you know, Prop. 39 is an existing building population, and to what extent we believe that projects are happening and bringing those buildings up to code.

And so, you know, how much of that is happening incrementally because of Prop. 39. That's really the fundamental question.

MR. KAVALEC: You're probably aware of the baseline analysis that's starting with the -- we're doing with the CPUC, looking at actual compliance issues and other opportunities for savings, and end uses that don't meet the code and, particularly in existing buildings.

COMMISSIONER MC ALLISTER: Yeah, I think that's a very, very necessary discussion. So, I'd really like to see that moving along and get as much of that into each successive forecast as possible.

CHAIR WEISENMILLER: Yeah. Well, I had to listen to testimony, yesterday, about how no one complies with our existing building standards so --

COMMISSIONER MC ALLISTER: Exactly. So, to that extent 758 is, you know, hopefully going to be a discussion for it and working on the compliance problem. But I think in terms of getting, you know, anticipating real savings that we can sort of say they're likely to come from that effort, I think that's pretty difficult until we get down the road and we have some experience.

And, you know, again, we're going to have a lot of discussion in the 758 context, and further down the road on the IEPR, about end-use data for purposes -- not just for the forecast, but for other kind of market activation purposes. And I think that's a really

important discussion at the policy level going forward. So, thanks.

MR. KAVALEC: Okay. The next slide. The final topic, demand response. The latest terminology to use when talking about demand response that gets incorporated on the demand side is load modifying demand response. And the actual definition of what constitutes load modifying demand response is still being discussed at the CPUC.

But currently, we include two types of load modifying demand response in the demand forecast. Non-event-based, which includes time of use rates and load shifting. And then event-based, which is critical peak pricing and peak time rebates.

As I say, this discussion or the definition of load modifying is still being hashed out. And when that gets resolved, it's likely we're going to have more programs to include as load modifying demand response in our demand forecast.

We get these numbers, what we currently use, from annual IOU Load Impact Reports that come out in April. Currently, in the last forecast at least, we had a total impact on load out ten years, between 200 and 300 megawatts. This is for all the IOUs combined.

And as I said, this is going to become more

significant once we resolve the specific definition of load modifying versus supply side demand response.

We are also, at the same time, working with CPUC and Cal-ISO staff on an analysis of TOU rates.

CHAIR WEISENMILLER: Actually, based on the direction of President Picker, myself, and Steve Berberich, that also had better include fixed charges and other rate design changes, period.

MR. KAVALEC: They are in there.

CHAIR WEISENMILLER: That's good.

MR. KAVALEC: So, we are expecting much more widespread penetration of TOU rate structures starting in 2018 or so, on the residential side. So, we thought it would be prudent to attempt to start measuring what the potential impacts of widespread TOU rates on the residential side are going to be in terms of load.

And we have developed six scenarios that assume varying levels of participation and hourly structure, and do include fixed costs, fixed charge. We're concentrating on the residential side. However, we're also looking at small commercial, which hasn't been totally integrated into TOU rates, yet.

Two of the scenarios that we're developing are specifically to address the duck curve issue, and that is low net supply during the middle of the day, followed

by a steep ramp up to your peak in the evening.

So we, and ISO, specifically, is looking at projected load shapes out ten years and attempting to develop a rate structure to address the duck curve.

There are obviously many uncertainties in this kind of analysis given we're talking about new hourly structures that we don't have any experience with. And we have to base the results in terms of people's response to various pilot programs that have happened around the country.

We don't have anything, really, in terms of experience with a much larger general population TOU rate impact.

So, anyway, my point is there are a lot of uncertainties. And our position, at least up to now, is that this analysis will be stand-alone and won't be incorporated directly into the demand forecast.

COMMISSIONER MC ALLISTER: Are you -- there has been quite a bit of work done on this, or at least a few reasonably large studies in California on time of use and on, you know, some of the technology components like, you know, how do people respond to thermostats and some like that. But there is some analytical work on response to time varying pricing, right?

MR. KAVALEC: Yeah, so there's enough studies

out there to where I think we can come up with something reasonable for --

COMMISSIONER MC ALLISTER: Yeah.

MR. KAVALEC: -- in terms of pricing elasticities, how people respond. But, you know, there's wide variation in those pilot studies and so you're going to have a large -- you know, any way you view this, a large band of uncertainty.

COMMISSIONER MC ALLISTER: Yeah.

MR. KAVALEC: So, we thought this would be a good first step just to develop a general sense of what these impacts might look like. And then, when we have specific plans to look at it at some point in the future, we can hopefully incorporate impacts directly into the forecasts.

COMMISSIONER MC ALLISTER: Yeah, great.

CHAIR WEISENMILLER: Yeah, that makes sense. Again, I think this year starting the analysis and just trying to understand the potential, but certainly not in the baseline at this point, right. I don't know whether the PUC decision you can process, but no one anticipates that being done in time to really give you a chance to make it into the forecast variables.

COMMISSIONER MC ALLISTER: Yeah, and this is also an area where it's relevant for the existing

building stock. And if it drives -- you know, if we find that there's major driving of behavior change through rates, and that that has potential to drive the Governor's third goal, then we obviously want to put that into context. Right now, it's not -- doesn't have to be in there, but this could change.

CHAIR WEISENMILLER: I think the other thing to make sure they're on the table is the last time, after we'd gone through, after doing energy efficiency, I think we then rolled into the PUC's LTP, and people looked at the DG or the behind-the-meter forecast and said, oh, my God, they don't match up. So, in this year's process we need to find a way to again get some consistency on assumptions on self-gen, the behind-the-meter stuff, be it DG, rooftop, you know, CHP, you know, storage, whatever. We need to have a conversation with the technologies, among the three agencies, and get that. Because, ultimately, the net load numbers, as you said, again, are what we're trying to get to in some point. And that of not just energy efficiency, but if there's a lot of rooftop solar, that also affects what's going on or what the need is.

And so, basically, you've done a lot of analysis on it. I mean, the PUC has done analysis, also. So, we just need to figure out a way to -- DOG workshops, or

whatever, to at least get out some of these differences. Obviously, ZEV's sort of another area, although I think that conversation is more with the Air Board. Although, I would anticipate the PUC to get somewhat more interested in those forecasts, also.

MR. KAVALEC: Okay.

CHAIR WEISENMILLER: The other one which, again, just to make sure it's on the record, that's very important to President Picker, is as the PUC gets more into, you know, distribution planning that trying to figure out a way to map -- as far as you can disaggregate down into their planning areas, since they're trying to make sure that when the distribution plans come in the summer, you know, that it's relatively consistent with our adopted forecast. Although, there's a certain amount of magic, or whatever, to try to convert our forecast as far as you've gone down to what a substation load is. As you know, it's a really disaggregated area. But some way of trying to get -- President Picker really wants to -- and this is certainly a strong point, trying to get some consistency between the DG that's submitted and our forecast.

MR. KAVALEC: Okay.

COMMISSIONER MC ALLISTER: At some level what our interface is, you know, too much granularity is no

longer a good thing. But for if we are -- if we're serious, I mean if we are serious about the climate goals, we've got to be able to get to a point down the road and agree across the agencies that we have some equivalence, or some appreciation of where different resources compare and don't. And so that we can -- and for advancement purposes needs to be at a relatively local level, right, in terms of distribution grids. So, what's the pathway to get to that agreement across the agencies.

CHAIR WEISENMILLER: Yeah, and again I think all of us know that going from where we've gone down to that level is going to have a lot of uncertainty. But at the end of the day someone has to do it. I mean, certainly in all these various models. And so, at least if there's a conventional wisdom on it and it's transparent. That's the other thing I really want is to make sure everyone knows this is how you get from A to B. You know, it may not be perfect, but at least this is the convention and there's discussion among planners on what's the best way to do that.

COMMISSIONER MC ALLISTER: Yeah, and along with that sort of the risk of uncertainty assessment, you know, like where you get to an answer. You know, what are the air bars and can we -- you know, are they too

wide to be able to actually use it for planning. That's a pretty key piece of data that needs to be dragged on down to the lowest level.

CHAIR WEISENMILLER: Yeah, so anyway, I think conceptually, again, I'm thinking more that we're trying to sync up generally the preferred resources, not just energy efficiency this time. And at least have an understanding about how to get to the -- how this can feed into the distribution learning process.

MR. KAVALEC: Okay, well, that was all I had.

MR. RHYNE: Okay, good. Thanks Chris. All right, thank you, Chris.

So, our next presenter is Anise Brian (phonetic), and I'm going to pull up here presentation. Anise.

MS. BRIAN: Good morning, my name is Anise Brian and I work in Transportation Energy Forecasting Unit, or TEFU, of the Demand Analysis Office. And I'm here today to talk about Transportation Electrification and Electricity-Using Transportation.

Next, please. I think that the best way to start this thing is to kind of clarify what we mean by transportation electrification. And what I have done here is to divide this transportation electrification into two sectors, on-road and off-road. And we borrow

the on-road from mostly the DVM, that identifies all vehicles that go on public roads should be at the DMV.

As you can see here, in the second rectangle to the right, we also have public transit which includes short-distance light rail and high-speed rail. So, obviously, these are not on roads as we see them, but they are -- so I put them all into one category and called them on-road.

And another reason why we make this distinction is that for the on-road transportation we have our own internal models and we use them.

Whereas for the off-road, as I will explain later, you're going to solicit the services of another consultant.

On-road transportation refers to -- or transportation electrification for on-road travel transportation is basically travel with personal vehicles, and that is for both residential and commercial customers, as well as mass transit, like light rail, like buses, like conventional rail that we have in California, and there's one high-speed rail that is going to begin operation in 2022.

On-road transportation also relates to goods movement and service trucks. And this is we're talking about freight, goods movement, but also service trucks

that are used in short-term purposes for activities, such as utility trucks that are serving utility customers, and garbage trucks, concrete mixers, et cetera.

Off-road transportation electrification refers to the extent to which seaports and airports, for instance, will be electrified. We call this off-road because many of the equipment and vehicles are in these ports and not all of them are registered. Not all of the equipment are registered.

And other off-road vehicles are marine vehicles, recreational, agricultural, or warehouses, and construction and mining. So, they're used in all of these different sectors.

I should add that in the past forecast, in the past IEPRs, what we have done is we have taken off-road vehicle numbers from EIA, and we have been using a simple growth model to grow them over the forecast period.

Obviously, the intrinsic assumption in that kind of methodology is that none of these off-road electrifications are going to happen. The Commissioners advised us to incorporate electrification and that's what we're doing this time around.

The next, please. Off-road transportation, this

is a table that we have borrowed from EPRI's 2011 Report on the project. These are basically examples of different vehicles and equipment that are operating correctly on transportation fuel.

As you can see here he's using, for instance, the gasoline, et cetera, but they all have electrification options. And so, with our off-road transportation electrification we'll try to hash out how much of it is going to remain diesel, how much of it is going to be electrified and what is that going to do to electricity demand for this sector.

As you can see here, in this particular table that EPRI has, they include passenger rate as off-road. And, actually, they refer to it not as off-road, they refer to it as non-road. But we are using a way in our on-road model, so that is one difference between the two.

This slide is focusing on the transportation major forecasting models that we own here, at CEC, and with these models we are able to project sector-specific demand for transportation image. These sectors include freight, transit, personal auto for both commercial sectors, commercial light-duty vehicles, as well as residential light-duty vehicles, and aviation models.

All of these models are economic models. And

what that means is that they account for the impact of time and cost of an activity on the demand for a product. So, if price of something goes up, obviously, the demand for that something is going to go down. When it comes to transportation, another type of cost that is involved when it comes to travel is the travel time.

So, when time of travel goes up in one area, then also one mode, then consumers are going to use another mode.

In addition to the cost and time of an activity, we also did economic models that account for income and/or economic output in different choice processes. If there is a growth in income, obviously, there's going to be a growth in diesel ownership. And with the growth in diesel ownership, then we are going to see an increase in new vehicle sales, which is going to increase the market of electric vehicles being purchased.

All of our models only account, when it comes to the transportation energy, they account for the tank-to-wheel energy consumption.

The next slide, please.

COMMISSIONER SCOTT: Can you say just a little bit more about the tank-to-wheel consumption?

One of the reasons I ask is I was thinking on

the slide before that one, for ships. And, you know, the primary fuel, of course for ships, while they're traveling across the ocean is that residual fuel. But then they come and they plug in when they get onshore. So, when you're accounting for tank-to-wheel, that's not counting that part?

MS. BRIAN: Well, these are the models that we operate in -- actually, see, this is our own model.

COMMISSIONER SCOTT: Uh-huh.

MS. BRIAN: So those for the ships we are using -- actually, we are going to talk about this a little bit later. Aspen Environmental Group, and we're going to have them to do that forecast.

COMMISSIONER SCOTT: I see.

MS. BRIAN: So, this is why it specifically relates to the models that we build and operate inside the Commission.

COMMISSIONER SCOTT: Okay.

MS. BRIAN: This slide talks about the light-duty vehicle demand, which is a major part of transportation electrification. And our light-duty vehicle demand models are quite unique and actually more extensive than many others that are offered in other State agencies. They cover all kinds of fuels, everything ranging from diesel gasoline, hydrogen,

electricity, ethanol, et cetera. So, we cover a wide variety of fuels in our models.

And as such, what we do is create a competition between them. So, the model is allowed to substitute between different fuel types, as we are required to do. These models (inaudible) -- for inter-fuel competition, and between all the different fuels. So, if the price of gasoline goes up or down, then it is going to have an impact on demand for other types of fuels.

Other key factors that we have, in addition to fuel prices for instance, is the diesel price which has a prominent role in the demand for electricity or demand for market for different fuel types.

If the diesel prices of one fuel type are very high, that is going to mimic demand for vehicles with that fuel type, and vice-versa.

We also allow for fuel economy, range, acceleration, and a whole bunch of other factors that we incorporate in our model to be able to forecast light-duty vehicle demand.

I should also say that our model is also the only one that I know that distinguishes between commercial and residential sectors. And that is important because commercial buyers have a different behavior compared to residential buyers. A commercial

buyer may want to buy, for instance, a PHEV because that gives them the flexibility whenever they are going on their business trips to shift fuel.

Residential customers may have higher preferences for EV, for instance, because then they can just charge their vehicles overnight and they can go the distance that they want, and they usually travel smaller distances.

Commercial owners may have preferences for time it takes to get to a fuel station. On the other hand, residential customers may want -- residential buyers of vehicles may only be concerned with the fact of can they charge their vehicle or can they fuel in certain locations or not. So, time is not as much of a factor for them, as it is for the commercial buyers of vehicles.

We also use a simple growth model to forecast electric vehicles, so that one is not necessarily a behavioral model. But our light-duty vehicle demand models are behavioral economic models.

The next slide. Other transportation electricity use, we also have transit models. One of them is called urban transit model and the other one is called intercity transit model to refer to short distance and long distance travel. And, therefore, to

the extent that these sectors are electrified, we also account for those.

When it comes to long distance travel, we are accounting for high-speed rail. Commissioners directed us last IEPR to account for high-speed rail and we did so. But the high-speed rail, at the present time, is a post-process stage of our model. We first generate our demand in our own models and then we account for the impact of high-speed rail on everything else. If more people are traveling with high-speed rail, that means fewer out that are traveling on road and, therefore, we have to make adjustments for it.

And then we also have our own model for goods movement and service trucks, where we are accounting for different fuel types in this sector.

There is another unit in the Demand Analysis Office, another model that's called transportation, communication and utilities. And this model accounts for electricity demand used in the transportation sector. So, these are the stationary uses of electricity and that amounts to electricity used, for instance, in bus stations, in rail stations, in fuel stations, et cetera, et cetera. And that is a separate model from the one that we are operating.

Environmental group will be forecasting

electricity use in seaports and airports, as they have other off-road stationary and mobile equipment uses in transportation.

Next, please. The key uses to our on-road transportation energy demand forecast, as everybody can imagine, is energy prices. Energy prices are going to be very important. It's one of the significant factors that drives our model. And our staff is forecasting petroleum-based fuel prices, this is based on EIA crude oil prices. I'm sure you all have heard about what has happened to crude oil prices these days. So, nobody really dared to forecast crude oil prices these days. And we are waiting for EIA to generate their forecast. Hopefully, mid-March, EIA is going to be presenting their crude oil price forecast and we are going to use that to generate our own transportation fuel or liquid fuel price forecast, which is gasoline, diesel, ethanol, et cetera.

Electricity and natural gas price forecast are the same as those used in the division's electricity and natural gas demand models. My colleagues, later, are going to talk about electricity and natural gas price forecast.

When it comes to plug-in electric vehicles, which is the major component of this transportation

electrification, other inputs are quite important. And that is what we call, in general, refill attributes, the most important of which are the vehicle prices. So, the relationship or the energy price of these vehicles, compared to other vehicles are very important in the decisions of the household whether to buy these vehicles or not. Since we are forecasting, for instance, the diesel prices for EVs are going down in the future, then that is going to move up demand for EVs in the future, as their prices become more competitive with other fuel types.

If price of fuel cell vehicles are higher than price of EVs, customers are going to buy more EVs and fewer FCVs, and vice-versa. So, these are important factors that are going to determine demand for PEVs.

I should say, also, that when we are forecasting demand, the penetration has been mentioned so far is that we do not -- our models are going to generate demand for these vehicles. So, we are forecasting the sale of these vehicles and then, every year, we are also forecasting population of these vehicles.

Penetration usually is there for penetration rate and some people take that as an assumption. This year is the output of our model, so EV penetration, PHEV penetration, FCV penetration, these are outputs of our

model, not an input.

In addition to vehicle prices, obviously, fuel economy is going to be important, and all these other attributes, which is acceleration, et cetera. These are provided by CRVH (phonetic). CRVH will be presenting their forecast or their preliminary forecast in the March 19 workshop.

Likewise, the petroleum fuel prices are also -- the forecast for those are going to be presented in the March 19 workshop.

Another very key component or very key input to our PEV demand models are customer preferences. And what we do here is assume this -- in the past we have assumed that these preferences are going to remain the same over the forecast period. One can imagine, however, with all the population shift that we were just talking about, Nancy was talking about, the growth of millennial, the baby boomers, et cetera, depending on what this ratio is then preferences could be different. By age, these preferences could be different.

I also want to say that our model, however, does not account for these age profile of the household. We only account for income of the household, not the age profile of the household. So, we could very well be missing that because we know that millennials would have

higher preferences for technology gadgets, such as PEVs, and if they are growing then they should be buying more of these vehicles.

On the other, if we have more baby boomers, empty nesters, they are using fewer vehicles and they are not as comfortable, probably, with these vehicles. But we are not accounting for that age profile.

Are these preferences going to change over time? Absolutely. We already have seen some changes in preferences. And the question is how do we project these changes in preferences in a way that would not be considered arbitrary.

So, we know for a fact that these preferences have changed and they will change in the future as more and more of these vehicles are entering the market. The suggestions on these, on projecting the changes in preferences, we would be very happy to incorporate those.

I should also add that another -- in addition to all the economic and demographic forecasts that Chris and Nancy talked about, we also use what is called American Community Survey. And we divide all of the households into different income categories, different number of workers, and different household sizes.

So, we are forecasting demand for each of those

household categories. So, if income of certain groups of households goes up, obviously, the number of vehicles that they are buying is going to change. If household size declines, as Chris and Nancy have been proposing, that can reduce the number of vehicles. And if the number of vehicles that households are purchasing is reduced, then obviously new vehicle sales are going to slow down and, you know, all the other vehicles are also going to also go down, too, as well.

Again, another factor that is very important when we are talking about households with different incomes is the fact that a lot of people are projecting inequity in income distribution is going to grow over time. But again, we don't have a good source to project income inequity growth. And that is very important because if you have more low-income households, low-income households have a tendency to stick to the conventional fuels. The higher income households have the tendency to buy those vehicles, to buy the newer vehicles. Also, the higher income groups, who are projected to move more into California, tend to buy more vehicles.

And our models are telling us that the more vehicles the household has, the more likely they are to buy PEVs.

So, all of these are important. But again, we are not accounting for age, we are not accounting for gender, and we are not accounting for income distribution. And all of those are important. Not that we don't want to, it's just that we have limitations on what we can do with the model.

When it comes to other transportation electrification assumptions and inputs, Aspen Environmental Group will be presenting their methods and their forecasts later in the IEPR cycle. But they do not have, there is no preference-based or economic models for off-road vehicles and equipment.

This is as opposed to ours, which are behavior based and an economic model.

And Aspen Environmental Group will attempt to use projections that are extrapolations of present inventories from different agencies, and they are going to use whatever data and resources that already exist in order to come up with this forecast.

I just saw something last week, from ICS, that has generated a transportation electrification forecast, and it included some of the off-road vehicles in it. So, I'm sure that Aspen Environmental Group is going to account for all of those differences.

The next, please. These are the proposed demand

cases. Obviously, our cases are going to be the same as everybody else. We have low energy prices, and what that means is that all of the energy prices are low, whether it is liquid fuels, like diesel, gasoline, or electricity and natural gas, all of them are low together.

In the mid case, mid demand case, all of them are in the middle together.

And in the low energy demand case, all of them are high together.

So, what that means is that this is going to limit the changing the relative prices of these energies. When all of them go up, or all of them go down, or all of them are direct lines this is going to limit the scope of price differentials in fuels.

So what we do, we have our own transportation demand cases, where we are varying prices in a different way. We have what is called high petroleum demand case, which is going to use low liquid fuel prices, high income, and high CNG, electricity and hydrogen prices.

When we have high petroleum demand case, obviously, we're going to have a lower PEV demand forecast.

Likewise, we are going to have a low petroleum demand case, which is going to be the opposite of the

above. We are going to raise the liquid fuel prices, that is petroleum-based fuels, and we are going to also use low income, low CNG, low electricity and hydrogen prices.

And in the past, what it does it is our low petroleum demand case generates a higher PEV demand than the common cases. And the high petroleum demand generates a lower PEV demand than a high case.

We should also say that all of these demand cases make certain assumptions. When it comes to vehicles, we ask Sierra Research to observe that all of the Federal and State regulations are in place, and all of the regulations for OEMs, and fuel suppliers are going to be in place. That is one of the directions that we give to Sierra Research for that.

We should also say that vehicle and liquid fuel prices are independent of California demand. And that is important because what this is saying is that whereas fuel prices are going to influence demand in California, demand in California is not influencing fuel prices.

Why? Because we are a small part of basically a global market.

Likewise, when it comes to vehicles, whereas vehicle prices are going to determine demand in California, demand in California does not necessarily

influence vehicle prices in the international market.

So, these are important, both the vehicle market and the petroleum prices are highly globalized markets that are influenced by other forces.

COMMISSIONER MC ALLISTER: So, just a quick clarification here. So, but which is not to say that the prices in California are the same as they are in other places, right?

MS. BRIAN: Yes.

COMMISSIONER MC ALLISTER: You have a good handle on the retail prices in California, right, our mixes and all that.

MS. BRIAN: Absolutely.

COMMISSIONER MC ALLISTER: Now, on the -- do we consider or is it a factor, really, the fact that we do have the seasonal mixes and the prices kind of jump around a little bit depending on how they're ramping up, or ramping down, and the weather and all that kind of stuff? Is that a factor that is necessary to take into account, the seasonal mixes?

MS. BRIAN: It would be good if we can include seasonal and regional differences in prices. It would be very good if we can account for those. But our model is a long-term demand model and we are just forecasting annual demand. And we are forecasting annual prices,

which is going to smooth out all these regional and seasonal price differentials.

COMMISSIONER MC ALLISTER: Thank you.

MS. BRIAN: I think that's it. And these are all the different examples of different -- you see in agriculture, for instance, all of these are -- I tried to find an electrified version of those, so all these pictures that you see are electrified.

MR. RHYNE: All right, thank you, Anise.

Just a housekeeping note. If you'll notice, we're pushed out into the lunch hour. We're going to go ahead and continue on through. We've got three more speakers before we're done and I think we'll be able to keep pretty close to our schedule today.

So, I'll ask everyone to sort of join with me as we sort of Ironman our way through the rest of these presentations. This is all -- and if your head isn't swimming, yet, we've got a couple more just to try and keep everything together.

So, this is the interesting part of what we do.

CHAIR WEISENMILLER: No, that's --

COMMISSIONER SCOTT: Right. Go ahead.

CHAIR WEISENMILLER: That's good. I think you may see some of us periodically disappear, but we'll be back.

But anyway, a couple questions. One of them was I was going to ask, we have a pretty good process, now, in terms of collaborating with the PUC on the energy efficiency numbers. I'm trying to make sure we've got similar collaboration going on with the ARB on the transportation side?

MS. BRIAN: We have been actually in the process of -- the consumer preferences that I mentioned before, these are a result of a survey that is -- they are now about a million dollars or so. And we have been collaborating with ARB in the design of those surveys and, actually, the questions that go into it. We have been working with UC Davis and EDPH EV Center, and all those. So, we are collaborating with a number of agencies, including ARB and Caltrans.

CHAIR WEISENMILLER: Great, that's good. And I suspect the PUC, over time, will get to -- given these fueling charging infrastructure questions, may get more interest in these numbers, too.

One observation, but when we talked about electrification of the ports, I was going to say certainly Long Beach has a lot of great programs there. And I would certainly encourage people to visit that or at least incorporate that.

COMMISSIONER MC ALLISTER: All right.

COMMISSIONER SCOTT: I had one on the -- you asked about the consumer preferences and, I'm sorry, I slid the chair just a bit.

But I always recommend, also, that you work with, you know, John Butler, Kyle Leanie (phonetic), in the Fuels and Transportation Division because we do have some studies at UC Davis, and other places, where they're looking at certain things like consumer preference, or other information that might be handy as you're putting together this piece.

MS. BRIAN: Thank you.

COMMISSIONER SCOTT: Uh-hum.

MR. RHYNE: Wonderful, thank you.

Our next presenter is Akoush Katam (phonetic), who will be speaking to the role of distributed generation in the upcoming demand forecast.

MR. KATAM: Hello everybody, my name is Akoush Katam and I'll go with the DG generation forecast for the 2015 IEPR.

The next slide. One of the things I wanted to start out with is the different data sources we use to get a handle on the amount of installation occurring in the State. Prior to the demand forecast we use utility rebate programs to get an idea where these PV systems or co-gen systems are being installed.

Some of the examples of these programs are the California Solar Initiatives, the Renewables Program, the New Solar Homes Partnership, and the Self-Generation Center Program.

As long as people continue to participate in these programs, the data from these programs are very helpful. But as in the case of the CSI, the California Solar Initiative, the incentives have dropped off and in some cases are no longer there for some of the utilities, the program data is not as reliable to get a handle on the amount of installation occurring.

COMMISSIONER MC ALLISTER: Actually, I don't want to raise the flag on that because I think there has been discussion and I'm not, frankly, not up to date on it. But, you know, I was very involved in the Solar Initiative when it was operating, you know, prior to coming to the Commission. And I agree, that source of data is just incredible, it's precious for being able to use in this context and many, many other contexts.

So, my understanding was that there was the talk at the PUC, at least, of requiring collection of that data and plugging it into the database, possibly via the interconnection process at each utility. And I'm wondering if you have a status update on that?

MR. KATAM: Yeah, I believe there was a

decision, at least last year, on that topic. And I think the utilities are supposed to start reporting that later this year. But in the meantime, we do have gaps.

COMMISSIONER MC ALLISTER: So, we have a gap in the utilities' tracking of solar -- or at least their release of public information regarding small, or behind-net-meter PV installations?

MR. KATAM: Yeah, specifically, the publicly available sources.

COMMISSIONER MC ALLISTER: Yeah, I guess, and so at the Energy Commission I would -- I mean, certainly, the utilities know when they have interconnection -- they know which of their customers have PV. And so, and they also would have some good handle on the interconnection date. I mean, a competent utility would certainly have that.

So, I guess I'm wondering if at the Energy Commission, whether or not it's public, we need to be asking for that information. Maybe you already are. But sort of that's kind of -- you know, that's the main course in terms of data for the forecast. So, I think we need to be able to make sure that we're going to be able to eat that. Please do not mention my metaphors.

MR. KATAM: The next slide. So, as far as the progress towards meeting the net metering caps, the PUC

asked the utilities to submit their progress. And we noticed that at least our collection of public data did not quite line up with what the utilities were reporting to the PUC. And this table here tried to show the difference in the 2013 cumulative stock here. You can see we were off by roughly 200 megawatts. And so, we're trying to figure out how to get a handle on this missing data.

And we kind of had two options, shorter term and the longer term. Short term was to request PV interconnection data directly on demand forms. And so, at least a few of these have already submitted their interconnection data for 2012 to 2014. And we did put out notice that the discrepancy from 2013 to 2014 has continued to grow.

So, it's going to be key for us to get a handle on these installations.

COMMISSIONER MC ALLISTER: Okay, well, great. I would actually ask the utilities to provide that information to us in its entirety, so we don't have to just rely on public sources. And that they, you know, explain the discrepancy between what they're reporting to the PUC and what's publicly available. I think that's a pretty no-brainer.

CHAIR WEISENMILLER: Well, no, I was going to

take a step further and ask if anyone from the utilities is here or, if they prefer, certainly in their written comments they can address that specific question.

COMMISSIONER MC ALLISTER: Absolutely.

MR. KATAM: So, asking for the interconnection data for the IEPR was kind of a plug for now. And for the longer term we wanted to take a look at our existing data regulations and figure out, you know, what we had to do to collect this data on a more regular basis. That's something that's still ongoing. You know, if we're going to have to go through a rulemaking, that's going to be a fairly lengthy process, but it's an option we are considering.

COMMISSIONER MC ALLISTER: I think that probably that's great, I'm glad to hear that. And I think there are probably other options just working across the commissions to make sure that, again, as an interconnection process that all systems have to go through, and that seems like an obvious place to kind of impose a reporting requirement.

It's not necessarily our job to do that, but certainly working across the commissions maybe we can move in that direction.

This is a key topic for public policy. I mean, this is not just they're our customers kind of thing.

We have been promoting DG for decades, now, and as it scales up it's very critical to know, just as it is on the demand side as we talked about earlier, it's key to know what people -- what systems are out there impacting the electricity grid.

So, obviously, I'm very interested in solving this problem in a structural way.

MR. KATAM: I was going to say, we do have data collection on interconnection from the utilities, but it has a pretty high sized threshold for reporting systems. It starts reporting at 100 kilowatts. And this is a lot on the residential and the smaller commercial so --

COMMISSIONER MC ALLISTER: Yeah, I think that 100 kW is kind of a symptom of the way -- of practice, more than any -- the utilities' are still, on the residential interconnection, the residential installation, they still know that that customer has solar and when it was interconnected.

So, I think there's a -- there is solid information there to be obtained and we need to work on how to get that done.

MR. KATAM: Yeah.

COMMISSIONER MC ALLISTER: So, and again, I'd concur with the Chair. You know, if there are utility representatives here that can comment on that, it would

be great to hear what their approach is going to be to getting us that information.

MR. KATAM: The next slide. Again, just on the PUC decision, what post-CSI did, you know, when that's up and running we will use that because it does have a potential, a lot of available information, so we look forward to using that.

For the non-PV, in the combined heat and power, we do get -- we've been able to receive regular reports from large CHP plants. This comes to us under our Form 1304. These plants are largely industrial and mining co-generation plants.

COMMISSIONER MC ALLISTER: Actually, can I jump in again, just to finish that previous point.

MR. KATAM: Sure.

COMMISSIONER MC ALLISTER: So, we're talking about a PUC decision that's going to cover the IOUs. Where are we with getting net-metered information, net-metering information from the POUs?

MR. KATAM: Oh, the POUs' report, kind of their version of the CSI Program through our Renewables Office, and we've seen -- you know, we collect that data from them. So, that's how we track the POUs' places.

COMMISSIONER MC ALLISTER: Do we have any way to -- so, in the case of the IOUs, we sort of saw that

there was a gap between the publicly-available data and what they were reporting to the PUC. Is there any comparable way to true up or calibrate the POU report data?

MR. KATAM: Right now they're still going strong so I don't think we're missing any kind of installation --

COMMISSIONER MC ALLISTER: Oh, they're still providing rebates for even the small residential?

MR. KATAM: So far, I think that's my sense.

COMMISSIONER MC ALLISTER: Okay.

MR. KATAM: But I can check back up on it. Modifying our existing regulations would solve a lot of problems because it applies to IOUs and POUs.

COMMISSIONER MC ALLISTER: Yeah.

MR. KATAM: And it doesn't distinguish between net metering or anything like that. It's just whatever the system is, whether it's a PV, micro-turbine, et cetera, so --

COMMISSIONER MC ALLISTER: Right. Okay, thanks a lot.

MR. KATAM: Yeah. The next slide.

I think the Chair had mentioned a little bit earlier about some of the issues in the last forecast about how some -- some of the changes we need to make to

kind of address differences in the forecasts we're having for customers' IDG. One issue was on the residential side to move away from these accepted average rates and to using more actual retail rates. And to facilitate that, we definitely needed some residential load shape data.

We did request that through our forms and, again, a few of the utilities have already submitted that. So, we're looking to get the rest of them to submit that data so we can continue making these revisions. This also allows us to treat net metering in more detail than we had in the past.

The next slide, please. Another change that we made for this cycle was updating our PV (inaudible) profiles. In prior cycles we relied on the New Solar Homes calculator for that.

In this instance, the PUC had agreed to trade a series of production profiles for them and we were able to obtain the data through an NDA (phonetic), so we're looking forward to using that.

COMMISSIONER MC ALLISTER: This is a shift from modeled data to metered data, is that right?

MR. KATAM: Yeah, so in the New Solar Homes Partnership calculator we're using more default, whereas what we obtained from the PUC were estimated generation

data from the bulk of the CSI systems up to 2012. So, it has a much more granular coverage that what we've been using in the past.

COMMISSIONER MC ALLISTER: Okay, but it was still model data or it was metered data?

MR. KATAM: It was similar data, but they did calibrate to whatever metered data they had access to.

COMMISSIONER MC ALLISTER: Oh, okay, got it.

CHAIR WEISENMILLER: I know the ISO is also trying to do the rooftop solar forecast, so it's good that all three agencies try to coordinate on that.

MR. KATAM: Yeah, we've actually had quite a few discussions already with the utilities on DG, than in prior forecasts. So, hopefully, this will go a long ways to resolving some of these issues.

The next thing of interest that has been -- energy storage. I know looking at the -- actually, the program data, it's about 75 or so megawatts of storage moving through -- that have been installed and moving through the application process. And so, we're very interested in accounting for the storage.

But, you know, we're not getting any luck in getting good performance data on how these systems work. But a PUC staffer has informed me that in the next evaluation report for the program, they're going to take

a preliminary look at storage impacts. And so, when that comes out we'll be looking into incorporating data from that report.

COMMISSIONER MC ALLISTER: So, just one clarification. So, just what's the role of the -- so, it's my understanding, and just correct me if I'm wrong, I guess, so you're trying to look at hourly or time -- time of use of impacts, or rate impacts in a more granular level, like hour-to-hour, to gauge consumer benefit or to gauge -- sort of what's the purpose of the more detailed rates, the time of use, you know, and the production profiles? You're mapping those together and then to get to what end?

MR. KATAM: Well, in the past when we used -- set the average rate, I think it doesn't mimic, replicate the private benefits of adopting PV. And so, if we move to more actually -- or the tariffs, or the actual rates people are displacing from the PV system and buying from the utility that can certainly help improve results. And then having production profiles more mapped to our climate zones will help improve results.

COMMISSIONER MC ALLISTER: But the end result being to gauge what uptick is likely to be based on the economic benefit to the customer.

MR. KATAM: Right.

COMMISSIONER MC ALLISTER: Okay. Now, I know where we're headed.

MR. KATAM: The difficulty is the extent the PUC's going to rate design, which --

COMMISSIONER MC ALLISTER: Yeah, exactly.

CHAIR WEISENMILLER: Yeah, presumably, that third or fourth tier is being smoothed.

Just a couple questions I had is one, as part of SCHIP are you also doing fuel cells? Again, assuming they're being the meter.

MR. KATAM: Yeah, we do get historically installation of fuel cells and we have a forecast for commercial sector fuel cells co-gen, so that's where that's coming from.

CHAIR WEISENMILLER: That's good. Now, we had a workshop in December on storage programs, and I will point you to the SMUD testimony there. My recollection of what they said is there was no problems on control technologies, although SMUD has done a lot of R&D on storage, that they were not optimistic. At least, a lot of the storage systems they put in didn't work, I guess is a better way of putting it. So, that would be at least good to look at that part.

And, finally, I was going to say on storage,

just to make your life even more complicated, some of the demand response proposals actually include storage. So, I think the one at Susan Kennedy's firm is about 50 megawatts. It basically does demand response by having behind-the-meter storage. Which, when it's time to -- among other times, when it's time to curtail, they basically pull out of storage, you know, that.

MR. KATAM: Yeah, there are other programs that we've heard about, the same kind of ideas, and it just complicates a lot of things but - -

CHAIR WEISENMILLER: Right. You're up for it, yeah.

MR. KATAM: So, my question would be on that, I haven't kept up with this completely, but are we expecting that grid operators will be controlling the storage in these -- in DR programs or --

CHAIR WEISENMILLER: Well, again, it gets to the nature of the programs. So, in that specific example, although I guess we could also do -- so, there's a couple of ways you could solve storage, right. One way of storage is to say, okay, I'm going to do a demand response program, put together a number of buildings, do some aggregation of those buildings, but also have the storage there to really backup if I have to.

The other way is you can fill storage, and

people do, is to say demand charges are high or getting higher, and so I will put the storage unit in behind the meter, shift things around to reduce your rates. And that would certainly just be controlled by the customer or by the aggregate. You know, in that latter, you know, rate thing would be controlled by the customer or the aggregator. While the demand response programs of, again, I keep calling Susan Kennedy, and I'm sure she's not the only one that's actually using -- you know, having at least very -- she's controlling it -- has a contract with her to deliver the results. So, indirectly, it's Edison really determining when the thing operates.

COMMISSIONER MC ALLISTER: I mean, up to now in California, since there hasn't been a robust demand response market, really, the customer -- the second model that the Chair just described, that's kind of the one that people are free to do because, you know, there's customer arbitrage, trying to keep their demand charges down and make sure that they don't get a spike that's going to cost them for the next 12 months, or whatever.

So, the customers have been free to do that, but the storage technology is just kind of catching up in a way that allows them to do it at some scale. But at the

same time, now, these markets for demand response services are likely to crop up and be more real to people. So, both of those things are going to be part of our efforts going forward.

CHAIR WEISENMILLER: Yeah, and some of that storage is more thermal than batteries.

COMMISSIONER MC ALLISTER: Yeah.

CHAIR WEISENMILLER: There's a couple of ways you can deal with the demand charges, right.

MR. KATAM: The reason I brought that up is it's -- the way it's operating is, I would think, going to be key in determining whether this is considered a load-modifying or a supply side.

And, you know, if it's load-modifying, it's going through our forecast. If it's on the supply, considered supply side, it's not.

COMMISSIONER MC ALLISTER: Yeah. And then, you know, beyond that if we're talking broadly carbon impacts, then when you charge or when you discharge really is fundamental to understanding what the sources that you're offsetting or not actually are. So that storage throws a lot of different complications into the determinations of what it's role's going to be or into just the system in general.

CHAIR WEISENMILLER: I would say that's trying

to straighten out interconnections and some of the interconnections have taken three years. And start watching the tariff and the first question is are you a load or a resource, and that stops storage. And, you know, you go on to the next point where you ask if you're a load or resource and it comes to total stop again. We're making progress on that.

MR. KATAM: The next slide. So, one of the things we want to do is work with the DOG to get better data sharing, especially with the utilities and other stakeholders that may have this kind of data, especially with storage. We're getting the charge and discharge profiles and how it all ties in with other forms of DG.

Next slide. There are some initiatives on the way to the PUC, from the passage of AB 227 that calls into a lot of things for the PUC to consider. Some of the important things that would have an effect for the DG forecast is the residential retail rate reform. There's a couple of components for that. There's a flattening of the tiers, imposing a fixed customer charge. And also, look towards the time-of-use rates in the 2018 to 2020 timeframe, I believe.

There's also the net metering redesign or how that will change once the caps are met, or the 2017 timeframe for shifting from current net metering systems

to a different one.

There's also distribution resource planning which will have a kind of granular focus on BG. A lot of these things are still up in the air and kind of going on the process of moving through the PUC. So, we're going to take a look at how these things get resolved and incorporate what we can in the timeframes we have.

And there's also, for the PV, the expiration of the tax credit.

These are some of the broader uncertainties that I wanted to kind of mention up here. And one of the things I was curious about was how do they see the impacts of these things and BG adoption.
And, hopefully, we'll see something in the comments on that.

CHAIR WEISENMILLER: Yeah, it would certainly be very good to get comments on these specific issues.
And, hopefully, not just the utilities, but also some of the consulting firms.

MR. KATAM: I think that was the --

COMMISSIONER MC ALLISTER: I think you laid out -- those are exactly the uncertainties that are all in here. Yeah, thanks very much.

MR. KATAM: Thank you.

MR. RHYNE: All right, so thank you very much.

And our next presenter is Lynn Marshall, who will be talking about the approach we're using this year to estimate retail electricity prices. So, Lynn.

MS. MARSHALL: Right, so I'm providing projections of retail electric rates to the demand forecast models.

Now, each of the major sector models, residential, commercial, industrial, and also transportation take as an input annual average electricity rates. So, while we're certainly facing some potential impacts from time of use changes and rate redesign, we can't at this point with the models on an annual time set, translate those effects into rates, into the models.

So, I'm focusing on the effects, changes in annual full load requirements and how they'll affect average rates.

The next slide. So, to put this in the context of a modeling system that Ivin discussed earlier, the rate model takes as its input assumptions about economic and demographic projects and, in particular household, new construction. And then, from the production model we're using the results from the common cases on generation by technology mix, fuel burn, heat rates and

that, of course, is driven in part by the natural gas price forecast.

But we're also going to be using a lot of the information submitted on the IEPR supply forms. First of all, we'll have resource balance information. And then, within the demand forecast there's two forms which request rate-related information. Revenue requirements by major cost category and revenue allocation to classes.

So, given where we are in the process, I won't have a lot of this final information until the second iteration of this process. In particular, the forms that request revenue requirements by cost categories aren't to be submitted until June 1st. So, I'll be folding that information in, in June.

So, today I'm going to talk about the data sources, modeling approach, and in particular I'll focus on the IOU construct. For the POUs, I'll be following a very similar methodology using the information that they submit.

So, in the previous IEPR cycles we've been developing rate projections using the E3 greenhouse gas calculator that was developed for the CPUC. And projecting rates really was not its primary purpose and we found it really didn't work well within our modeling

system.

So, for this cycle we've developed an in-house model. Essentially, a set of structural equations where we can model each of the major elements of revenue requirements at a more granular level. And we can include in that allocation of revenue requirements to functional categories. So, taking into account that some revenue requirements are allocated to the generation requirement, which is paid only by bundled customers, and some are allocated to distribution, which is paid by all customers.

And then within we include the demand forecast, with a price elasticity adjustment, consistent with the demand forecast model.

So, we're forecasting the IOUs and the POUs separately and then we'll construct the weighted average, and that will be the input map to the demand forecast sector destinations, and that will be the input into the demand forecast models.

The next slide. I'll talk about, go through the approach for forecasting the various elements of revenue requirements.

So, this is an overview of recent trends. And here's PG&E's annual revenue requirements. Total is currently about $13 billion. And you can see purchase

power is usually the largest, definitely the most volatile as it's driven by variation in natural gas prices.

But you can also see the second largest category, almost a third of rates is its distribution revenue requirement.

And then a much smaller percentage, but also growing rapidly, well, but hard to see, the transportation element. That's increased from about 5 percent of the rate to 10 percent over the last five to eight years, so that's another rapidly growing category.

The next slide. So, for Edison there's a similar story. You will notice with the loss of SONGS, so the purchase power element has increased a lot in the last two years and also, now, the generation element of the revenue requirement has decreased since they've removed SONGS from their rate base.

And then, finally, I have San Diego. Similar story, transportation is up to, now, about 15 percent of their rate.

So, I'll talk about each of the major categories and how we're going to model -- what data sources and modeling.

So, the first category is fuel-in purchase power. So, that includes natural gas purchased for

utility-owned generation and other fuel purchase. And then all their purchase power, including renewables, conventional and greenhouse gas costs.

So, calculating the net energy per load, taking into account utility-owned generation, and pricing that using the CPUC avoided cost approach of using a heat rate applied to gas prices, with the carbon cost adjustment.

For the renewables element of purchase power, using the IOUs' August 2014 reports on cost quantification reports, which report expected generation and all the current cost of renewables under contract. So then, the model internally calculates the additional renewables needed to be procured to meet their target, and the additional market purchases needed to meet their net energy per load requirement.

Okay, so next slide. So, for the overview of the general rate case element. So, this is, for PG&E, it includes the recently adopted general rate case. So, what you can notice about this is that the operating and maintenance costs relatively small. There's a lot of overhead, taxes, administrative cost.

But the largest portion is association with the rate base, right. So, we have depreciation expense, which is the return of capital on additions, and we have

the rate of return. The weighted cost of capital is currently around 8 percent for all the utilities. In this low interest rate environment, that's probably not going to increase for several years.

And for PG&E, about 72 percent of that is associated with distribution assets. So, distribution rate base is, I think, an important element of this forecast to pay attention to.

So, the next slide. Think of the traditional drivers of distribution infrastructure growth, new customers, growth in peak demand, interconnections, and then a certain amount of ongoing maintenance and reliability upgrades that aren't driven by -- so much by demand growth.

But, of course, we're at this really significant juncture here for distribution infrastructure investment. We won't see the resource plans until July, but I think we maybe had a foreshadowing of what those will look like with some proposals by PG&E and San Diego to invest in infrastructure to support electric vehicle integration. And those would become, essentially, part of the distribution rate base, potentially.

So, how are we going to forecast that? We've started a -- we have a technical support contract just starting that's going to have two elements. It's going

to develop forecasting methodologies that we can use within our process, if we take advantage of some of our econ demo drivers, to forecast the portion of distribution infrastructure growth driven by demand and customer growth.

And then, also, in conjunction with some other work that we have a pilot study going on, looking at cost-effective strategies for integrating distributed resources. So, we'll develop some scenarios to look at how this distribution infrastructure may unfold under various cases.

So, we're hoping by -- so, according to the schedule, by next summer we should at least have some initial results on that, that we can incorporate.

Okay, the next slide. So, utility-owned generation, pretty straight forward. So, we'll use the historic data calibrated to our production simulation model output for the various common cases. And then use historic data to forecast -- we project estimates for ongoing O&M and maintenance costs.

Okay, and then next, transmission costs. So, most of our transmission-associated investment is under the auspices of the CAL-ISO's transmission planning process. And as part of that, they do prepare estimates of the effect on the transmission access charge.

So, go to the next slide. So, this shows the forecast from their 2013 and 2014 transmission planning process. They're expected to have revised estimates of this from their draft 2014-2015 transmission plan. That should be available in April, so we'll incorporate those estimates.

And then, as part of our tech support contract we're also going to evaluate the transmission forecasting methodologies for things like the infrastructure growth, and how that might interact with expanded penetration of distributed resources and renewables.

Okay, and then we can go on to the common cases. You've seen this before, but the basic story for rates is you have -- in the high case we have high demand, chief staff, and in the low case we have weak econ demo, low demand, and high natural gas prices.

So, on the next slide. These are very preliminary results. I don't have all of the results of the recent production simulations models folded in, yet. But they're indicative of I think the results we'll see.

So, as you saw with Chris's econ demo scenarios, there is more upside in the high cases, so we have more potential impacts on rates in the high case. And that's also true of the natural gas and the carbon prices we're

using. So, the variation's about one-and-half cents on the upside and only one cent down on the low side. And I ran this for all three of the IOUs.

So, you can show Edison. We lost Edison. There's a similar result -- there's a two-cent impact in San Diego on the upside, a larger impact there.

So, okay, do you have any -- so questions?

CHAIR WEISENMILLER: Yeah, I have a couple. I think we both do.

So, the first question is in terms of the utility current financial situation, do any of them have significant financial over or under questions?

MS. MARSHALL: Well, it's interesting when -- so, San Diego has submitted their general rate case and they requested an increase, but there actually would not -- even if they got the full increase which, of course, they won't.

CHAIR WEISENMILLER: They won't, yeah.

MS. MARSHALL: It would be a very -- I think, actually, it would be a rate decrease because of the balancing account effects.

CHAIR WEISENMILLER: Yes.

MS. MARSHALL: So, there seems to be an overage there. That's the only major one I can think of.

CHAIR WEISENMILLER: Yeah, I remember when I was

doing retail rate forecasts that sometimes they overrun their collections.

MS. MARSHALL: Yes.

CHAIR WEISENMILLER: Real significant. The other thing was I was obviously looking at pending or projected rate cases.

MS. MARSHALL: Right.

CHAIR WEISENMILLER: Others, you've indicated, typically, if you look at the utility projections they assume 100 percent recovery. And I think the PUC informally uses more like 50 percent of --

MS. MARSHALL: Yeah, so right now, so in the Edison rate case, the record is closed, so we probably get a decision this year. But I'm not making any adjustment for that because -- so, Edison requested an increase. So, ORA have proposed decreases. So, I think at this point I'll just leave it as it is.

CHAIR WEISENMILLER: Well, that's typical that the utility asks for an increase and then -- it's about half.

MS. MARSHALL: Well, there might be both increases, and then you can split the difference. So, I think splitting the difference is that I leave nothing changed until I get it.

In San Diego, I think the intervenor testimony

briefs will be available in April and May, and so I may be able to fold that in in terms of a likely effect on their rates.

CHAIR WEISENMILLER: Yeah, certainly, if you can talk to the folks in the Energy Commission on what they're expecting on the stuff they're revising, their internal forecasts.

MS. MARSHALL: Okay.

CHAIR WEISENMILLER: Anyway, it gives us another data point. At least, again, as we try to collaborate, the more we're consistent, is better.

MS. MARSHALL: Yes.

CHAIR WEISENMILLER: The other one is in terms of just thinking -- I mean, do you go to the next step and say this is what it means for the residential rate class, as opposed to the industrial rate class based upon however the Commission now does revenue allocation, as opposed to rate -- I'm not talking about rate design, but revenue allocation.

MS. MARSHALL: Yeah, so right now I'm using the current factors for revenue allocation and rate design. But in the way the model's set up that's an annual factor. So, to the extent of decisions, or some -- or you could do a sensitivity on how those revenue allocations could impact. You know, if we converge

closer to marginal costs for residential customers how would that -- so, that's definitely a case that some -- an exploratory analysis that could be done.

CHAIR WEISENMILLER: Okay.

MS. MARSHALL: Yeah.

COMMISSIONER MC ALLISTER: Let's see, so on the transmission stuff, I guess you're -- yeah, so you're working closely, I imagine, with the ISO to kind of keep a handle on that?

MS. MARSHALL: Yeah, they'll be providing -- they actually do a little -- a transmission access charge forecast and they -- for each of the approved projects. And they're actually in the process of revising that model. So, hopefully, in the next month or two I'll be able to incorporate that.

And it's nice because it's a very transparent calculation of what cost assumption they use, and all the various parameters they use to calculate revenue. So, we could model -- one of the things we could as part of the tech support work is to evaluate all of the other assumptions and see how that -- to be consistent with our own forecasting approach.

COMMISSIONER MC ALLISTER: Yeah, I mean I think that would be good due diligence, so just really clarifying that that's happening.

So, the rate cases are generally every two years, right. So, how do you -- so, you have this sort of near-term onslaught of information to sort of figure out, okay, where is our starting point in the near-term. But could you talk about, a little bit, about what happens in those middle years and the later years in terms of where your assumptions kind of pan out?

MS. MARSHALL: Right, so I'm using -- so, I have recent -- PG&E, I have an adopted value through 2016.

COMMISSIONER MC ALLISTER: Right.

MS. MARSHALL: I don't have that for Edison or San Diego. So, I'm assuming rate -- to develop these initial scenarios, I assume 6 percent rate base growth, which is kind of a recent trend.

So, we have to make some estimate to come up with something like a reasonable forecast. And as we get into this, I think part of our -- especially, with distribution tech support analysis, is to really explore how the proposals that are out there, and strategies for integrating distributed resources could impact that. So, those are the types of scenarios we want to --

COMMISSIONER MC ALLISTER: Yeah, so I agree with that. I think at the energy that the utilities can spread across their rate base changes, at these different scenarios you're going to end up with

potentially, you know, reasonably different results over time. So, it's good to see -- it's good to hear that you have sort of a yearly tweak that you can make.

MS. MARSHALL: Yes.

COMMISSIONER MC ALLISTER: So, that helps. So, I'm trying to get a sense of what the long-term vision is for this and it sounds like you've got a nice way to get from where we are now to where we may be going, and explore scenarios.

So, two other questions. One, where are we -- it seems like this analysis is really heavily dependent on IOU information and working with the PUC on that, and the formal rate case progress, I guess.

Where are we with the POUs? I would want to encourage us to dig into at least the big ones, do similar forecasts for them.

MS. MARSHALL: Yeah, I intend to. And because this is a new model and there's just a plethora of data available for the IOUs, I really focused on that, first. And then this spring, as we get the demand supply forms, and rate information from the POUs, then I'm going to focus on them. And I will be using their information as much as possible.

COMMISSIONER MC ALLISTER: So, we have the platform to get that information?

MS. MARSHALL: Yeah, those are requested. So, we have the demands -- on the demand forms we're requesting, we have some rate-specific information which requests costs, procurement costs, capital investment plans, generation and transmission, fuel expenses. So, if they complete the forms, then that will be very useful. In particular, a historic data so that I can calibrate our forecast methodologies, especially for the larger one, to their specific rate characteristics.

COMMISSIONER MC ALLISTER: Okay, great. And then I have just a clarifying question on your slide 9, the PG&E general rate case. I just don't understand the percentages there and what you're trying to convey with that?

MS. MARSHALL: Okay, so this isn't a graph of the rate base. So, you're right, that's not 70 percent of that. But I'm saying so that -- those top two layers, okay, those are the part of their total general rate case revenue requirement associated with earnings on the rate that's two parts associated with capital investment. There's the earnings on the rate base and there's the depreciation expense, which is a return of principal.

So, of that, that total top two bar area, 72 percent of that is associated with distribution assets

as opposed to generation assets.

COMMISSIONER MC ALLISTER: Oh, okay.

MS. MARSHALL: So the point is here, when you want to look at projecting general rate case revenue requirements, you really want to focus on distribution infrastructure.

COMMISSIONER MC ALLISTER: Yeah, yeah. I guess I'm just not -- so the percentages there, over to the right, don't seem to match up to the size of the wedges.

MS. MARSHALL: Oh, that. Okay, annual cost element -- well, look at the top bar, annual average growth rate.

COMMISSIONER MC ALLISTER: Oh, the growth rate, I'm sorry.

MS. MARSHALL: Yeah.

COMMISSIONER MC ALLISTER: Okay, my bad. Okay, got it. So, the scale's in the side of the bars and the growth rates are the other side

MS. MARSHALL: Okay.

COMMISSIONER MC ALLISTER: Okay, got it, thanks. Okay, that's all I have. Okay, great. Thanks, Lynn.

MR. RHYNE: All right, thank you very much.

And for our next presentation, Leon Braithwaite will be talking about the North American Natural Gas Model. Leon.

MR. BRAITHWAITE: Thank you, Ivin. Commissioners, good afternoon. My name is Leon Braithwaite, if you didn't know that before. I work in the Supply Analysis Office, upstairs.

The next slide, please, Ivin. This afternoon I will be speaking about two items. Item number one is the key elements of our natural gas model. That is known as the North American Market Gas Trade Model. You'll hear me refer to that as NAMGAS.

The second item that I will be talking about are common cases, at least from the perspective of the natural gas model, and that we are doing for IEPR 2015.

The next slide, please, Ivin. But before I do that, before I get deeply into what we are going to do this afternoon, I just want to take a step back and explain to you how we got to where we are today.

The NAMGAS Model is created in what we call the market bill of platform. It's a platform that we have leased from Deloitte Market Point. They are the owner of this platform and we have been leasing this particular platform for quite a number of years. We then construct our model within that platform.

In the 2013 IEPR, we decided to take the World Gas Trade Model, which was the model that we previously ran here at the Commission, and narrow the focus to only

North America. To do that, we had to do several things.

Number one, we reconstructed the California portion of the model so that we can more focus on California. Because here we are in California, we live here and want to know what's going on, at least in the world of natural gas. We removed all non-North American structure.

And, of course, natural gas being an international commodity, we had to (inaudible) some sort of north or some sort of structure to simulate the international portion of the natural gas market.

We also added -- so, as a result, we added some functional notes for the import and export of NRG. We added some structure to represent the natural gas demand in the transportation section. This we had not done previous to 2013, but now we do have individual demand use that will take care of demand in transportation.

And we intend to maintain this structure -- to maintain this structure for our 2015 work that we are now engaging in.

The next slide, please. So, if I can just give you a simplified view of the model. What we do have is the following. We have natural gas supply basins connected to interstate pipelines and intrastate pipelines, and that is connected to demand centers.

The model, once we upload our data, the model then is arranged between three main components. At the end of the day, we will produce amounts of supply, demand, and HUB prices. We then use those HUB prices to generate end-use prices. This process, this procedure is an offline procedure. This is not done inside the model. All of our end-use work (inaudible) -- use is done outside the model.

The next slide, please. So, if you can look at what is going on in our first component, the major component, which is the supply basin, we have two things that we need in each of these basins. We need a resource assessment. That resource assessment tells us how much natural gas or how much natural reserve is available and how much of it is recoverable.

But in order to recover this commodity, we must have some sort of extraction cost. So, this comes into play as a resource cost.

We put these two items together to come up with what is known as our natural gas supply cost curve, which is shown on the next slide. Ivin, please.

So, if we go, if you look at this curve and you start from your far left, and go to the right, this started in 2007. We put the schematic starting in 2007, the blue curve. The red curve is 2011. The green, I

would say is 2013. And that purple, odd-looking color, is the 2015 curve.

Now, I just want to be clear about something. This particular curve doesn't appear anywhere in our model. What you are looking at is an aggregation of somewhere between 300 and 400 gas supply curves to produce this curve that you are seeing.

Well, what is evidence here is that the curve is shifting to the right. What that means is that we are having more gas available at lower cost. This is the effect of technology. And as you know, there is a lot of discussion about this in the press, in terms of the development of shale resources. The shale resources are contributing to this phenomenon we're seeing in these curves, more gas available at lower cost.

And we must remember, also, during this time period we are producing somewhere between 20 and 23 PCF of natural gas, but yet the curve continues to shift to the right. More gas, at lower cost.

The next slide, please, Ivin. In the demand centers we have disaggregated our demand centers into five sectors, residential, commercial, industrial, port generation, and transportation. Now, each one of these sectors needs some starting in demands. And please underline the word "starting", because they are just

starting demands.

So, how we do this, how we get these starting demands is through some sort of regression analysis. We have regression equations for each one of the sectors. We go through this process with the independent grid, which are listed here on our slides.

For example, industrial sector, our independent grid was recent historical demand for natural gas, natural gas prices, core prices, industrial product and core weather. These independent grid is going to generate our starting demands that we will input in our model. This process is also done offline.

The next slide, please. On this slide, we see the independent variables for core generation. Core generation gets a lot of attention and we do see quite a (inaudible) -- grid.

The independent grid was there, our two-time electric generation, weather, natural gas price, load price, renewable electrical generation and core price. These independent variables is what we use to get our starting demand in the core generation sector.

We also have independent variables that we use to get the starting demand in the transportation sector. Now, this is only applied outside California because for inside California, our colleagues in the Transportation

Department will provide us with the necessary values to run our model.

We also have the elasticities that we use in each one of those sectors. Each sector has its own elasticity.

So what happens is the price is determined in the model, where demand will fluctuate depending on the elasticity that we input. So at the end of the day, we will get out a demand that is different from what you started with because of the fact prices change within the model and it changes the demand within the model. It's the general model dynamic every -- maybe 20,000 times, maybe 40,000 times before we can get our final solution.

The next slide, please, Ivin. So these are the three common cases that we use to (inaudible) -- as a part of this process that we are engaging in. We will have a mid-energy demand case. We can call that our reference case. We have a low-energy demand case and we have a high-energy demand case.

What we are attempting to do here is to try to put some boundaries around the uncertainties in prices, in supply and in demand. Boundaries, we are trying to establish a zone of uncertainty, if you will.

The next slide, please, Ivin. So in the mid-

energy demand case, our initial starting demand in the United States, in 2012, we have about 22.1 PCF. For generation we have 7.7 PCF. In 2030, in the United States, it's about 26.2 PCF. For generation, it's about 10.6 PCF. Remember these are starting demands. At the end of the day these are going to look a little bit different because of the elasticity contained in the model.

We are going to have some core conversions. Right now we are talking about 50 gigawatt. That may change as we go through our process. That's where we begin in 2014.

The Renewable Portfolio Standards, California released its environment on time, where right now assuming a five-year delay in other states, we are hoping to get some feedback from our stakeholders on this assumption. And we will certainly consider any input that we may get in regards to that.

CHAIR WEISENMILLER: Yeah, can I ask a question? The question I have for you, Leon, is obviously the Obama Clean Energy Plan, which gets to reducing coal and increasing renewables, among other things, and they have, EPS, very specific plans for every state.

MR. BRAITHWAITE: Yes.

CHAIR WEISENMILLER: There's a lot of

controversy on those, but I was just trying to figure out in terms of our assumptions on either coal conversion or renewables how that tracked back to the Obama or EPA plan?

MR. BRAITHWAITE: Well, Commissioner, right now we are going through our analysis on this very issue. And as I said, this coal conversion number that we have here, where this is just our first level estimate. We are expecting this number actually will probably rise as we go through our forecast cycle.

But really, at the end of the day, this will be 50, 60 gigawatts. It just depends on what our analysis shows at the end of the day. But we are taking those things that you're raising into consideration as we go through this analysis.

CHAIR WEISENMILLER: But again, EPA has said, just in terms of your timeline, keeping in perspective that this summer they will come out with a final plan.

MR. BRAITHWAITE: Sure.

CHAIR WEISENMILLER: Now, whether that's July or September, you know, it may have some implications for us. At least there's some doubt on precisely when in the summer.

But, you know, generally we've been very supportive of that plan, particularly in the California

context. But again, looking out across the nation, there's at least a data point to give a lot of consideration to.

MR. BRAITHWAITE: Once EPA comes out with this plan, Commissioner, we do plan to take that plan, go through it, and see how it affects our work. And wherever it's necessary for us to make changes and incorporate the EPA direction, we will incorporate that into our work.

CHAIR WEISENMILLER: Okay, that's good. And Melissa has been pretty active on that. In fact, she was just in Denver, Monday, on the sort of response. So, the more you can forward her back into this, the easier it will be for you to get on top of what's in the plan.

MR. BRAITHWAITE: I most certainly will, Commissioner.

Continuing with the mid-energy demand case, we have two categories of natural gas reserves in the model. One we call the pooled reserve, the other we call the potential.

The pooled reserves are those reserves that only operational maintenance cost is required for production.

The potential reserves, on the other hand, both capital costs and operational maintenance costs are

required for production.

At this point in time we are looking at about 360 PCF in the United States of pooled reserves in our model. On the potential, at $5.00, we are looking at about 1,376 PCF.

We also have some investment parameters for resources, about 12.2 percent. On the pipelines it's about 8.4 percent, and so on.

We also have something called a backstop technology and I just want to explain that for one second. A backstop technology is the following, it is unspecified. It's not anything that you would recognize, it's just unspecified. What happens there, theoretically, is if prices within the model rises to $9.00, and if it's sustained, then this new technology would bring in the energy units that will replace the natural gas in the world of our model. That's what our backstop is. So, right now it's unspecified at $9.00 per million -- I'm sorry, per thousand cubic feet.

We also have a technology factor. Right now, we are assuming technology will increase at about a one percent rate.

The next slide, please. On the low-energy demand case we are looking at core conversion of 80 gigawatts of coal-fired generation. And, of course, as

the Commissioner rightfully pointed out, we will be taking into consideration the EPA's work that is projected to be out in the summer. We will still be taking that into consideration as we continue to construct these cases.

We are assuming a high economic growth, around 3.5 percent. We are assuming on meeting the RPS standards all over the United States, except in California. In all cases, California will be meeting its RPS standards.

NRG, we are looking at some NRG exports. That is still under consideration. That may change as we go through this process.

And we will take -- this particular scenario, we will take this in a high-cost environment. All other things being equal, a high-cost environment will tend to shrink the resource bases.

The next slide, please. In a high-energy demand case, we are talking about converting about one gigawatt of coal-fired at this time. As I said before, we will be taking into consideration EPA's work as we finalize these numbers.

We assume that all states meet the RPS targets on time. Economic growth will limp along at about two percent. We will assume technology grows about two and

a half percent, expanding the resource base.

We're also going to put this scenario into our low-cost environment. All other things being equal, this will also tend to expand our resource base, our natural gas resource base.

The next slide, please, Ivin. The last thing I want to talk about is the development of the end-use HUB prices. Now, this is done outside the model, not inside. So, what happens is once our model is -- once you have gotten a nice solution to our case, we will extract the HUB prices from the model. We'll then, in a spreadsheet, we will get the sheet to what it costs to move the gas from one of the HUBs, which one of those HUBs we choose, whether it's PG&E HUB, or Merlin HUB or SoCal HUB. We see what it costs to move the natural gas from that HUB to (inaudible) --

Once we get a transportation cost, we will add the transportation cost to the HUB price and we'll get an end-use price.

Now, that's a very brief explanation of what happens. It's a little more complex than that. My colleague will continue. Peter can probably tell you a lot more about this.

But this is essentially the process that we go through in terms of getting our end-use prices.

The next slide, please, Ivin. This takes me to the end of our presentation. Before I end, I just want to say the following. We are seeking input in nearly all of these assumptions. If our stakeholders, or anyone else, has any input to what we are doing here, we would love to hear from them.

With that, I'll end my presentation and I'll take any questions that you may have on the dais. Thank you very much.

CHAIR WEISENMILLER: All right, that's good. As I said, I think my major point is, yeah, EPA.

MR. BRAITHWAITE: Definitely.

COMMISSIONER MC ALLISTER: I don't have any questions. Thanks.

MR. BRAITHWAITE: Thank you very much, Commissioner.

MR. RHYNE: Okay, so we've reached the point in the day where we can open the floor to public comment. We'll begin with folks here in the room. If you have questions or comments, I don't think we've collected any blue cards yet today. I'll ask, if you have a question or comment, you can come to the center dais, the center podium there. Please identify yourself, identify your affiliation, and then you can make your comments.

I'll ask everyone to keep them relatively brief

and succinct.

So, we'll first open it here in the room. Once all the speakers in the room are done, we'll open the questions and comments to folks who are participating online.

So at this time, if there are people in the room with questions or comments, please feel free to approach the podium.

MR. ALVAREZ: Good afternoon, Commissioners, Manuel Alvarez with Southern California Edison. One just quick question for Chris. On the Moody's and the Global Insight data, if I recall you use the averages of the figures that come out of those documents or -- I can follow up later, if necessary.

MR. KAVALEC: I'm not sure what you mean, the average of what?

MR. ALVAREZ: The average of the data that you get from Moody's and Global Insight, do they give you just a single point, or just a single point of information? Or I thought there was a series of data that was filed.

MR. KAVALEC: Yeah, so they provide scenarios. So, we pull out the scenarios. We don't do any averaging between different scenarios.

MR. ALVAREZ: Okay, that's fine. And I guess

the other question I just wanted to raise was the question that Commissioners brought up, about the solar information.

MR. KAVALEC: Yeah.

MR. ALVAREZ: We're aware of the gap between the data and we're trying to work on that right now.

COMMISSIONER MC ALLISTER: Okay.

MR. ALVAREZ: As of today, I haven't heard any real concerns about that. And if there is, I'll let you know, the availability of that information.

COMMISSIONER MC ALLISTER: Yeah, I mean I have -- I've heard some concerns just like, boy, it's hard to dig in and get that information. But I don't -- the quality of the content, I haven't heard anything.

MR. ALVAREZ: Yeah, every time I deal with data, I deal with it in multiple levels from the conceptual are to the actual, practical collection and the filing of that information, and the storage, and where it resides within the company.

COMMISSIONER MC ALLISTER: Yeah.

MR. ALVAREZ: So, thank you.

COMMISSIONER MC ALLISTER: Okay, thanks.

MR. VONDER: Okay, hello, Tim Vonder from San Diego Gas & Electric. Thank you for the presentation. It was informative.

What we -- so, maybe through dissemination through the DOG would be the inputs that you're going to be using to do your forecast in kind of a laid out form, so that we can see them?

For example, we'd be interested in knowing, you know, the specific releases and dates of each of the Moody's, and Global Insight scenarios, so that we could put the same data down as you're using, and maybe compare it to what we're going to be using.

So, the detail of that nature, if you could kind of make that available through DOG, to the IOUs, then we can see that.

And as you develop the scenarios on the input for DG and EV, and so forth, if you could -- when you fill out forms, like we fill out, if we could provide more detail so that those assumptions can be documented.

Because when we -- after your forecast is finally adopted, we use your forecast for many different reasons and sometimes we need to get at the detail that's in there, and if it's documented all in one place that would help a lot.

And we'll be following up with written comments, you know, some of the things I'm saying right now. And I think that's about it for right now.

MR. KAVALEC: Well, thanks for the additional

work you're making us do.

(Laughter)

MR. VONDER: Sorry.

MS. BIRD: Thank you, Commissioners and staff for the very helpful presentation. I'm Katherine Bird, from PG&E.

And I wanted to respond, specifically, to the questions of Commissioner McAllister, and his concern on the difference in the PV forecast. And we're really interested in working together with the staff on truing that up, perhaps through a DOG process. And, particularly, we're interested in discussing the cost assumptions because some of the CSI-based cost assumptions really may not be accurate anymore.

Also, I think our teams are interested in perhaps transitioning from a payback approach, in terms of cost to, given the current environment, where so many leases are available, or low-cost loans, or no-cost implementation. So, our team would really like to work together on truing those forecasts up and getting closer.

And I might, now that we have actually submitted our form on the PV interconnection data, already and, hopefully, that's helpful.

MR. KAVALEC: Yeah, that's helpful and thanks

for submitting that data.

MS. BIRD: Okay, great. And then, you know, in terms of what other data's not being submitted on your form, that we're also going to submit through the CPUC process, certainly we'd be happy to look at integrating that.

COMMISSIONER MC ALLISTER: Great. So, I'm all about, definitely in support of looking at better ways to model adoption and what the true drivers of that are. And, obviously, customers respond to the information they have, and PPAs are a key part of the marketplace in that way. Absolutely supportive of that.

And I guess I was really asking just about the accounting problem of how many systems there are, and what their capacity is, and when they were interconnected to PG&E's grid, and concern that there was a discrepancy, seemingly, between two sets of data that PG&E -- that both of which PG&E generates, or at least plays a key role in. So, one being the CSI, you know, participation, and the other being what we -- you know, a larger group of installations that's being reported to the CPUC and those two things not adding up.

MS. BIRD: Well, I think part of the problem, and I'm not the subject expert, you know, we had a discussion with Melanie McCutchin (phonetic), and your

staff, earlier.

COMMISSIONER MC ALLISTER: Yeah.

MS. BIRD: But I think part of the problem is that the CSI data doesn't capture all the market. And so, the new form that the staff has requested is actually more comprehensive and should address part of that.

COMMISSIONER MC ALLISTER: And so that would have the right -- that would reflect the numbers that are being submitted globally, the global numbers that are being submitted to the PUC, so --

MR. KAVALEC: Yeah, so that's coming straight from their interconnection, instead of the program.

COMMISSIONER MC ALLISTER: Yeah, okay. So, I have an interest in just having there be a long-term solution to tracking behind-the-meter installations of all technologies, not just solar.

MS. BIRD: Right.

COMMISSIONER MC ALLISTER: And just having that all be a matter of course and not having to have this kind of a discussion again. And I think we're headed there at the PUC. And with that kind of thing, too, I just wanted to raise the flag until it actually is in place.

MS. BIRD: Right, and I think we, too, support

that because we're concerned about the discrepancy. So, thank you so much.

COMMISSIONER MC ALLISTER: Yeah, thank you.

MR. CHAUDHURY: Good evening, Commissioners and the staff. I'm Sharim Chaudhury. I work for the Southern California Gas Company and I have a question for Chris. And Chris, Commissioner McAllister asked you earlier about the granularity of the demand forecast. And you had mentioned that the basic model that you have is going to spew out for the forecast at the county level. And maybe outside your model, somehow we could take your forecast and provide more granularity to it.

So, is that some of what you are thinking of for the 2015 IEPR? I'm trying to understand what the demand forecast will be out, what the final forecast would look like.

MR. KAVALEC: Yeah, so in terms of further disaggregation beyond our climate zones, that's something we're going to have to take up when we're done with the forecast. There's no firm plan on how, specifically, we're going to further disaggregate, yet.

MR. CHAUDHURY: Okay, thank you.

CHAIR WEISENMILLER: But again, one -- two issues that Chris is dealing with on that further disaggregation, and one is as far as we can tell, on our

econ demo forecast, uniform across the State on a disaggregated basis has sort of become impossible. So, certainly, if you have solutions there, that would be great.

The thing, which I think ultimately on the disaggregation, the more disaggregated data we're getting from you, the easier it is to benchmark between that.

MR. CHAUDHURY: Yeah, I sympathize with Chris because as a modeler, you know, I know how difficult it is to get the driver, the economic and demographic driver, at a very disaggregated level and the quality of that. So, thank you.

MR. KAVALEC: So, Sharim, do you at all attempt to do forecasts below the service territory level for SoCal Gas?

MR. CHAUDHURY: No, currently we do at the service territory level, okay, we don't do it at county level, but that's something we are thinking about.

MR. KAVALEC: Okay, thank you.

COMMISSIONER MC ALLISTER: And I guess I would just say, so the econ demo is a limitation because it doesn't get granular. And that makes sense, right, because to get the trends you need a lot of -- you have to do statistics on a lot of data to find where the

trends actually happen.

But in terms of energy consumption and, you know, buildings data, and the distribution grid, itself, and there are lots of sources of information that actually are more disaggregated than that. And so, I think the question we started at before was how -- you know, what methodologies you're going to use that don't require the same kinds of econ demo at the localized level, but that still let you do some kind of forecasting from that, say, county-wide baseline. Right, and so where do you actually -- what kinds of things can you say about trends in say construction, land use, whatever to get at smaller scales in terms of the gas distribution grid or the electricity distribution grid that allow you to do better planning. And so, I think that's where we're all trying to get at is defining, thinking about what the limits of that actually are. You know, not throwing up our hands on the econ demo and saying, hey, we can't go further. But figure out how we can go further and whether that's relevant.

MR. CHAUDHURY: Thank you.

CHAIR WEISENMILLER: Chris, the other two things I was just going to add is, obviously, along the econ demo the other thing we have to make sure, as we're

looking at the preferred resources, that they're equally disaggregated. You know, just saying that a particular energy efficiency program does something this much service territory-wide, you know, you're going to get to how do you start doing that allocation.

And at the same time, having said that, it's very hard to get very specific to disaggregation. Ultimately, when people want models -- you know, at some point it is substation by substation. And, obviously, that's not what Chris is or can forecast.

But in terms of at least everyone having a conversation about how do you go from that, what it can do, down to that spreading it out among really detailed stuff for the power models.

MR. CHAUDHURY: Yeah, I agree. Thank you.

MR. KAVALEC: And retirement is looking better and better.

(Laughter)

CHAIR WEISENMILLER: Yeah, I've actually been assured this Administration, those of us are older, you know, it's perspective. It's like the Governor's 76 and it's like what do you mean

MR. RHYNE: Thank you. Any further comments or questions from the audience here in the room?

All right, seeing none, it looks like we have --

MS. RAITT: There seems to be one person on WebEx who had a question. Raymond Johnson, I think we're going to open your line, if you're there and have a question?

MR. MARTINEZ: Yes, it's actually Ed Martinez from Southern California Edison. I'm just using Raymond's log in.

MS. RAITT: Okay, great.

MR. MARTINEZ: I'm in the Long-Term Demand Forecast Planning Division of Edison. To follow up a little bit on what Manny had asked you earlier, we had a senior slide (inaudible) -- for specification, so we weren't sure if you were doing an average of both Moody's and Global Insight. It looks like you're doing -- you're using Moody's just for a couple of baselines, and you're using Global Insight for some alternative scenarios.

Could you just quickly comment now, or at a later date could you just give us, I guess, some of your impression or assessment as to what caused you to use Moody's as a baseline, instead of Global Insight?

MR. KAVALEC: Yeah, it's actually very simple. Because in our contract with Moody's right now, we get data down to the county level and we don't get that with Global Insight.

MR. MARTINEZ: Okay.

MR. KAVALEC: It makes it easy.

MR. MARTINEZ: Okay, I can understand that. So, thanks a lot.

MS. RAITT: Is there anyone else on the WebEx, Stephanie?

Okay, then we can go ahead and open up the phone lines. We just have a couple of phone lines. So, if you're on the phone line and you had a question, we're going to open up the lines and this is the time to ask.

It sounds like we don't have any. I think we're done with the public comment.

COMMISSIONER MC ALLISTER: All right, so any other comments from the dais here?

Well, I'll just -- I'll bring us home. I guess, so I would qualify this as a successful first IEPR workshop. I'll make the executive decision to say that. And, you know, perception is reality, right.

So, but I definitely appreciate, again, everybody being here. This discussion always is -- it's super interesting for the initiated because, really, we all know how important it is.

But it also can be a little bit insider baseball because the initiation, right, is long and arduous. So, a lot of us, I think -- the discussion isn't necessarily

the most accessible one to say the public. So, I think these issues really are representative of how complicated some of these -- you know, long-term forecasting is, and some of its importance maybe gets lost in the discussion.

But again, I just want to pull us back to the importance of getting a good, solid forecast. And just the history that we have of doing it and the adjustments that we make forecast to forecast, and the world throws curveballs at you, and you've got to figure out how to adjust and still have a credible story about what's likely to happen going forward.

And our staff knows that in spades and really does a good job on their particular sectors pulling together these cases, and making the right assumptions, and kind of -- there's a lot on the one hand. On the other hand, it takes both. And those calls can seem subjective, but we all try to ground them in reality the best we can.

So, and we rely on the comments that come in from the utilities and from other interested stakeholders, knowledgeable parties, and our contractors who provide us with data to ground those decisions, and to make sure that we're proceeding in a way that makes sense, and have some consensus around it.

So, this is really where the rubber hits the road in that regard. And, you know, this is the place where we want to kick off the IEPR. It's really appropriate that we're talking, the forecast is really ground zero for the IEPR, itself, and for many folks that are going to be doing work based on it in the future.

So, anyway, thanks for indulging me there. Really appreciate Ivin, Heather, the whole team that's been working on these. Thank you very, very much. Obviously, your expertise comes out very clearly.

So, with that I'll wrap this up and consider us adjourned.

Did you want to say anything else, Heather?

MS. RAITT: I'll just make a plug that we have a sign-in sheet at the entrance to the hearing room. And if you didn't sign in, if you could go ahead and sign in, that would be great.

COMMISSIONER MC ALLISTER: And March 11th for comments on this topic.

So, thanks very much. I think we're done for today.

(Thereupon, the Workshop was adjourned.)

--oOo--