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Preparation of the 2013 Integrated Energy Policy Report (2013 IEPR)

Lead Commissioner Workshop on Preliminary Electricity and Natural Gas Demand Forecasts 2014-2024

California Energy Commission
Hearing Room A
1516 9th Street
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10:02 A.M.

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Also Present (* Via WebEx)

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Public Comment

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P R O C E E D I N G S

MAY 30, 2013 10:02 A.M.

MS. KOROSEC: All right everyone, thank you for your patience. We're going to go ahead and get started now.

Good morning. I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit. And welcome to today's workshop on the Energy Commission's Preliminary Electricity and Natural Gas Demand Forecast for 2014 to 2024.

We're fortunate today in having not only Commissioner McAllister and Chair Weisenmiller, who are leading the IEPR this cycle, but we also have Commissioner Ferron and President Peevey's Advisor Brian Stevens, from the PUC, and we're expecting Commissioner Florio momentarily, and Mr. Keith Casey, who's representing the California ISO.

So, welcome gentleman, thank you for joining us today.

A couple of housekeeping items before we get started. Rest rooms are in the atrium, out the double doors and to your left.

Please be aware that the glass doors near the rest rooms are for staff, only, and will trigger an alarm if you try to exit the building that way.

You can get coffee or snacks on the second floor, at the top of the atrium stairs, through the door that’s under the white awning.

For lunch we’ve provided a list of restaurants that are within walking distance of the building and that’s on the table in the foyer, with the other handouts.

We plan to take lunch a little later today, probably around 12:30. So, please feel free to go grab a drink or snack to tide you over, as needed.

If there’s an emergency and we need to evacuate the building, please follow the staff out the building to the part that’s kiddie corner across the street, Roosevelt Park, and wait there until we’re told that it’s safe to return.

Today’s workshop is being broadcast through our WebEx conferencing system and parties do need to be aware that you are being recorded.

We’ll make the audio recording available on our website in a few days, after the workshop, and we’ll also post a written transcript within about two weeks.

Along with time for Q&A during today’s presentations, we’ll also have two opportunities for more general public comment, the first one just before we break for lunch to accommodate those of you who may not be able to stay for the entire day, and then the second one, then, after we complete our afternoon presentations.

We’ll take comments first from those of you in the room, followed by those participating on the WebEx.

And when you’re making comments or asking questions at any time during the day, please come up to the center podium and use the microphone so that the people on the WebEx can hear you and so that we can get your comments reflected in the record.

It’s also helpful if you can give our court reporter a business card either before or after you speak, so we’re sure that your name and affiliation are reflected correctly in the record.

For WebEx participants, you can use the chat function to tell our WebEx coordinator that you have a question or a comment, and we’ll either relay your question or open your line at the appropriate time.

For phone-in only participants, we’ll open all of the phone lines after we’ve taken comments from the folks in the room and folks on WebEx. We ask that when we do open the lines please mute your phone, unless you plan to speak, because otherwise we get a massive burst of static when we open the lines.

We’re also accepting written comments on today’s topics until close of business on June 10th. And the notice of today's workshop, which is on our website and also on the table in the foyer, explains the process for submitting comments to the IEPR docket.

So, the demand forecast is one of the foundations of our biennial IEPR and it's a fundamental input into California's energy planning process.

Our most recent adopted forecast was prepared during the 2011 IEPR proceeding and adopted as part of the 2012 IEPR update.

One of the major issues with the forecast continues to be how it accounts for efficiency and conservation savings.

And the energy agencies are continuing to work together to improve the demand forecast and the related planning processes to properly account for those savings.

And we're also working closely with Stakeholders through the Demand Analysis Working Group, which is a forum for those who are interested in demand forecasting and energy procurement.

Recommendations in the 2012 IEPR update that related to the demand forecast include expanding the CEC's analysis of the potential effects of climate change on the forecast; providing the forecast results by climate zone as a first step toward a more disaggregated forecast that can support better distribution system planning and also help with identifying priority renewable development zones for distributed generation; and, finally, doing a better job of considering all of the uncertainties in the forecast that are related to implementing California's policies for adding zero emission vehicles, combined heat and power, and distributed generation.

For today's agenda, the morning will focus on the preliminary statewide results of the forecast and the methodology that was used, and also hear about economic and demographic projects, and challenges with disaggregation of the forecast.

We'll then provide time for general comments for those of you who aren't able to stay for the full afternoon session, and then we'll break for lunch.

After lunch, we'll cover the impacts of DG in the forecast and then get into the individual planning area forecasts for the IOUs, LADWP, and SMUD, with opportunities for comments and responses from each utility.

We'll then end the day with a final opportunity for public comments before we adjourn, hopefully, before 5:00.

So, now we'll turn to the dais for opening remarks.

COMMISSIONER MC ALLISTER: Thank you, Suzanne.

My name's Andrew McAllister and I'm the lead on the IEPR this year. And I'm very happy to be here and be trying to shepherd this very large endeavor that Suzanne and her team capably handle. It's quite impressive actually. They're a very well-oiled machine on this, on the IEPR.

As Suzanne said, the forecasts are really foundational for many of the things that the State does in the policy and planning arena in our energy sector. So, this is really bread and butter stuff for certainly all of us on the dais and our respective agencies.

I want to thank our representatives from the other agencies for being here, most notably Commissioner Ferron from the PUC. I'm really happy that he could join us, as well as Brian from Commissioner Peevey's office, or Chair Peevey's office -- President Peevey's office, rather, sorry.

I really think, along with Chair Weisenmiller, I know we're -- I am very happy to be collaborating increasingly tightly with the PUC on many of these issues, and this is foremost among them, really.

Getting a handle on energy efficiency,

distributed generation, electrification of our vehicle fleet, and all of these other, all of the issues that feed the forecast and that impact demand going forward are so critical to understand that I think all of us can, rolling up our sleeves together, figure it out, and at least come to a conclusion that’s useful, equally useful for all of us.

I also want to thank Keith, from the ISO, for coming. Thank you for being here.

We’re eagerly awaiting Commissioner Florio, as well. So, hopefully, he’ll be here soon because I know he’ll have some interesting views on this, as well.

So, I really thank you all for coming. And I know it’s taking a day to be with us here is not without its cost to you. But particularly people who are in the room today, but also on the web, really appreciate your input and helping us build the record in person, and also with your written comments as needed.

Very anxiously awaiting the presentations here, we’ve got a really good group today.

And I think with that -- well, I also wanted to highlight the challenges of the forecast. This is one step this year towards disaggregation, towards regionalization and localization of the forecast. But there’s a lot of work to be done in subsequent years, as well, to make that more of a reality.

In California, we are increasingly living an era -- we're increasingly having to deal with distributed decision making about our electric system.

So, customers are increasingly engaged in distributed generation, you know, adoption of different technologies, including vehicles, but other. It presents a lot of challenges up and down -- you know, from generation down through transmission, down to the distribution level, and the individual customer level, and so understanding those challenges, particularly as we move towards a diverse supply regime and more reliance on demand resources for our supply.

Demand response, another hot topic here in the IEPR this year, which I'm very excited about, and energy efficiency which we'll talk some about today, and all these other areas getting -- are areas getting a good handle on where they're going. And there's really no substitute for some localized and regional understanding of those, and working through how -- so, that obviously requires an increased level of data, granularity of data, analysis capability, big data becomes, you know, an issue there, and collaboration with a broad array of stakeholders, not just the utilities, which are obviously key to this process, but also others who are acting in the demand side space.

So, I think we have -- we've made a nice step forward this year towards realizing that vision of being able to handle this and understand our grid awareness, too, and I'm really excited about that. In subsequent years, we have even more to do.

But with that sort of broad sort of context, I'll pass it to Chair Weisenmiller for his comments.

Thank you very much for coming, again.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, thanks everyone for being here today.

I think this is a start of a process, as opposed to a conclusion. As you go through this, it will be clear that the energy efficiency topic is going to be later. I mean, we're basically all working together in the Demand Analysis Working Group, you know, building off of some of the PUC analysis and some of the other pieces we're going to really take a run at energy efficiency this year in a collaborate fashion, as all three agencies committed to the State Senate.

I think as we go forward, I think Commissioner McAllister pretty much hit the overall pieces.

There are two things I wanted to flag. So, energy efficiency, we're going to spend a lot more time in August in a workshop and feeding that back in.

But we also will look at transportation later, so transportation fuels. And as we're looking much more at electrifying the transportation system, that certainly has real implications back here on the demand forecast. And so that part, again, will be later.

Another aspect that will be later is climate change, you know, is happening now. Certainly, if you look at the long-term records, the temperature in California is 1.7 degrees on average higher than it was in the 1890s.

If you look out 10 or 20 years, it's going to again be increasingly hotter, it's going to be more persistent. And that will certainly have impacts on our electric system, both in terms of higher demand and reduced efficiency of a lot of our pieces of that.

And at the same time, today we'll look a lot at the econ demographics and which, you know, if you look at -- in terms of what some of the major variables are, or drivers, I mean that's one of the really major drivers, you know, for our forecast, and certainly a lot of uncertainty.

I mean at the end of the day any forecast you do has uncertainties around that. And particularly, as we look more and more at disaggregation, the forecast, you know, there will be substantial uncertainties around, say, if we start splitting the L.A. load -- the Southern California loads up into L.A., one part of L.A. in the more central inland areas, again, there's going to be significant uncertainty in that split.

And certainly would encourage everyone to read Nate Silver's *The Signal and the Noise* as a way of, again, trying to make sense out of what's really important in forecast and what's, frankly, just noise and confusion.

So, again, thanks for your participation. We're looking forward to an interesting summer as we work through these issues.

COMMISSIONER MC ALLISTER: Well, as you can all see, Commissioner Florio was able to join us here and we're really, really ecstatic to have you and your colleague, Commissioner Ferron, with us today.

So, with that I'll give Commissioner Ferron an opportunity to say some words.

MR. FERRON: Good morning everyone. I'm Mark Ferron, for those who haven't met me. And I'm very pleased to be here today.

For those of you who don't know, I'm the assigned Commissioner for three important proceedings related to what we're going to discuss today, the energy efficiency proceedings, the renewable portfolio standard implementation and resource adequacy, so very glad to be here, very interested in this topic.

I think Commissioner McAllister and Chair Weisenmiller have really hit the key themes. But to reiterate that, we, here in California, have several challenges going forward. And I think we are in many ways leading the rest of the country, if not other parts of the world in terms of our response to climate change and the changes that that implies for the electricity system within the State.

A number of challenges ranging from how we address adequate resources in the future, what we do about firming up greater renewables, and the like.

And we have, I think, strived over the last several years to become very much more collaborative across the various agencies who are involved. There are many oars that are pulling this boat forward and we need to ensure, and I think we've done a good job of ensuring that we are pulling in the same direction, and increasingly pulling at the same time and at the same pace.

I think one of the critical issues here is what we'll address today, which is long-term forecast for energy demand because, obviously, we're making decisions, and the market is making investment decisions which are very long-lived. And so having a good understanding of what our long-term load requirements will be and what the drivers are I think is very critical.

I’m also very interested to look at the issue of energy efficiency and the impact on forecasts. I think it’s maybe clear to some folks that in the past there’s been somewhat of a disconnect between what we are planning to do in terms of energy-efficiency programs and that gets reflected in long-term forecasts.

And I know that there will be a lot of effort going forward, including the workshop we’ll be holding in August specifically to look at how we at the PUC can ensure that the programs that we design and that ratepayers fund are reliable in generating the savings that are reflected in long-term forecasts. So, that’s something to which we’ll be putting a lot of effort in over the next several months.

But I look forward to a robust discussion today. I think this is a very important topic and I’m very happy to be here. Thank you.

MR. FLORIO: Yes, thank you, a pleasure to be here, as always. I’m looking forward to digging into the forecasts.

I’m the assigned Commissioner on the long-term procurement proceeding at the PUC and, you know, the output of this process is an important input to our proceedings.

We've had some controversy in the past about forecast adjustments and I think the closer we can get to all being on the same page with what numbers to use will help with the very difficult issues that we face in planning for a very uncertain future.

So, I'm looking forward to rolling up our sleeves and digging in here today. Thank you.

COMMISSIONER MC ALLISTER: So, welcome to President Peevey's office and, Brian, if you have some words you want to say.

MR. STEVENS: Good morning, thank you so much for having me. My name's Brian Stevens and I'm an advisor with President Peevey's office at the CPUC.

President Peevey expresses his regret for not being able to be here. And I'm honored to be able to be here in his presence.

Just to give you some background, the CPUC regulates privately-owned electric, natural gas, telecommunications, water, railroad, rail transit, passenger transportation companies and cable television franchises in California.

And through all of that private sector

regulation our five Governor-appointed Commissioners, as well as our staff, are dedicated to ensuring that consumers have save, reliable utility service at reasonable rates, protecting against fraud and promoting a healthy economy in California.

So, leading up to this workshop I decided to go chat with some of my colleagues in the Energy Division who work really closely with the demand forecast and interact with the staff here at the Energy Commission in the development of the demand forecast every couple of years.

And I asked, well, what are your opinions of this? And the responses generally were that it's great that we engage in a healthy debate with the Energy Commission, and the CAISO, and other stakeholders in this because through that debate we're able to get a really robust demand forecast that really helps serve a lot of the needs of California's energy planning.

You know, there are stories where I talked with staff of previous LTTP cycles that were incredibly difficult to administer because the assumptions were all over the place.

And, you know, once we started having this unified planning process here, at the Energy Commission, things got much, much easier for the CPUC.

I wanted to give a little context to how we use the demand forecast at the PUC. Of course, we use it for RA compliance. We have very regulated RA compliance filings with the LSEs here in California, and the requirements and obligations are based off of the demand forecast.

Something that we're doing at the PUC is we're working on developing a new market for a flexible RA. And, of course, the demand forecast will play into figuring out exactly how we design that market.

The next one is we have a nuclear power plant that is out in Southern California, SONGS, and we're opening up a no-SONGS track of the LTTP. And, of course, the demand forecast will be crucial in understanding where we'll need to be in the future to be able to plan for a system without that resource.

And finally, the PUC is informally investigating ways that we can have more confirmation in terms of what energy efficiency and demand reduction through DR will be there in the future.

And the hope is that we'll be able to both inform the markets of what they can expect in the long run and also help develop a more robust demand forecast here at the Energy Commission.

So, with that I want to also highlight the importance of this, as noted by Senator Padilla in his letter to the Energy Commission, the PUC, and the CAISO on January 30th.

And my boss, and Mr. Berberich, and Chair Weisenmiller responded by saying that we’re going to build upon the progress we’ve already made in terms of collaboration and go forward with even better collaboration among our agencies.

And so, we’re very excited to continue working with these other agencies to get consistent planning assumptions to have the most effective energy planning we can going forward.

So, again, I want to thank you all so much for inviting me and the CPUC to be here today and I’m looking forward to the presentations. Thanks.

MR. CASEY: Well, first off I wanted to thank Commissioner McAllister and Chair Weisenmiller for inviting me here. I look forward to the presentations today.

The IEPR forecast is a critically important input to the ISO’s system planning studies at the ISO and we’ve been an active participant in the IEPR process. And, in particular, have been part of the collaborative effort that you’ve heard discussed by my colleagues here on the dais of really working together with the CEC and the PUC to get better alignment among our organizations on the long-term planning assumptions around achievable energy efficiency, with really the ultimate goal of getting more granular, rigorous estimates of achievable energy efficiency, and to ultimately move forward with cost-effective energy efficiency programs that ultimately displace the need for new power plants. I think that's really our collective goal on this effort.

So, we look forward to engaging on that effort. And, hopefully, I realize that that effort will dovetail into the IEPR process later this year, but I look forward to, hopefully, better understanding how that will come about.

There was a mention in some of the comments about some of the incremental progress in getting more granular load forecasts and more granular estimates of energy efficiency, and the ISO is very supportive of that effort.

I realize it's a work in progress in terms of how far we take it, but it's something I'm very interested in hearing more about today.

Because, you know, when you look at it from a planning process at the end of the day we want to have confident estimates of achievable energy efficiency at a very grid-specific location so that we can incorporate it into our planning studies and rely on it going forward.

So, it will be critically important as we develop those projects that they ultimately feed back into the IEPR load forecast so that we don't lose that granularity going forward.

And again, I realize that's very much a work in effort but -- work in progress, but it's something we think is critically important.

So, that's really all I had to say for opening comments. And again, appreciate the opportunity to be here and look forward to the presentations.

COMMISSIONER MC ALLISTER: Thank you very much, Keith.

I really just want to reiterate the collaboration. You know, I think the Senator Padilla's hearings were a good sort of impetus to push the interagency collaboration forward.

But, you know, more broadly I think it's just the right thing to do and I think we -- the nature of the issues and the challenges that we're confronting us today really are pushing us in that direction in fundamental ways.

And really, I feel fortunate to be on the Energy

Commission at the same time that at the ISO and at the PUC we have such a good group of collaborative and knowledgeable Commissioners and support staff, because I think it really does help.

It helps put the right stuff in the Petri dish so we can all, you know, grow the policy environment that we need to grow. It’s a bad analogy, but I think it’s apropos in some ways.

There are just a lot of good minds on this and I’m really sort of heartened and excited by that fact. And to have us all come together in the IEPR forum is really terrific.

So, I want to thank Suzanne, Lynette, and her team, the team there for putting together a series of really stimulating and useful, fruitful workshops thus far, and I certainly anticipate going forward, so the same goes for today.

So, I’ll pass it back to Suzanne.

MS. KOROSEC: All right, thank you.

Our first speaker today is Chris Kavalec, our Chief Forecaster.

MR. KAVALEC: Good morning, I am Chris Kavalec from our Demand Analysis Office.

A little bit more about our agenda today. I’m going to start out the proceedings talking about some statewide forecasting results, a little bit about methodology, some other key issues related to the forecast.

And following my presentation we're going to have a couple presentations from members of our Academic Expert Panel, who advise us on methodology-type issues related to our forecast.

First, we're going to have Hill Huntington from the Stanford Energy Forum, who's going to talk about our economic and demographic forecasts that we get mainly from Moody's and Global Insight, the strengths and weaknesses of economic and demographic projections, and whether they're in fact actually capturing all the uncertainty associated with economic growth.

And this is very important because, as the Chair said, the key driver in our -- for our forecast, notwithstanding all the efforts we've made for efficiency, is still the economy. And we saw that in the last recession, the difference in the electricity consumption and how it dropped during the recession.

Following Hill we'll have a short presentation from Alan Sanstad, from Lawrence Berkeley, who's going to talk about the disaggregation issue.

As we know, there are data issues involved in providing more granular forecast data. There are staff resource issues, but there are also important statistical issues related to disaggregating the forecast, and that's what Alan's going to talk about.

Following that we'll have, after the public comments, we'll have a presentation on onsite distributed generation or self-generation, how it's incorporated into the forecast and what impacts it has.

And then we'll round out the afternoon with individual presentations for each of the five major utility planning areas, SMUD, LADWP and the three IOUs.

And in those presentations we will compare our forecast to the most recent forecast done by the utilities, and then we will hear from the utility forecasters who will provide you their short presentations or comments.

Okay, in terms of schedule, here we are today at our Preliminary Forecast workshop. We call this forecast CED, or California Energy Demand 2013 Preliminary.

Following this workshop we're going to get started on estimating incremental, uncommitted efficiency impacts with Navigant, using the current goals and target study going on at the CPUC.

And these estimates are going to feed into our revised forecast to be released in August. And that revised forecast will, of course, incorporate any comments, internal and external, that we hear today or in written comments.

And shortly thereafter we'll have another workshop to present the revised forecast.

And if all goes well, we will have a final forecast adopted that incorporates incremental uncommitted efficiency in the fall of 2013.

My presentation today, I'm going to talk a little bit about methodology. I won't bore you too much, but we always have some folks at the workshop that aren't as familiar with our forecast.

Some statewide results, the critical inputs that go into the forecast, how we incorporate efficiency and what impacts it has on the forecast, the same with climate change, how we incorporate that and what impacts that has.

So, we have this forecast we're presenting today, CED 2013 Preliminary, but we also do an alternative forecast with more aggregate econometric models. And so, I'm going to compare the results of the two.

And there's some other miscellaneous issues to touch on.

When we forecast, we forecast for eight

different planning areas listed here. So, the statewide results that I show will be the sum of these planning areas.

For natural gas, and this is -- I'll point out this is end-user natural gas consumption, which means it doesn't include natural gas used for generation.

We have the three IOUs for natural gas and then we have some smaller entities that we combine together and call "other".

And in this forecast we're presenting results at the climate zone level, and this picture shows the climate zones. We have three planning areas that have multiple climate zones, PG&E, Southern California Edison, and LADWP.

And we will see specific climate zone results this afternoon when we present our utility forecasts.

Our slate of forecasting models, residential and commercial, are full end-use models, meaning they're bottoms-up models. So, we're starting at the level of average appliance usage or equipment usage, by type of equipment, at the -- per average home or per square foot of commercial floor space by building type on the commercial side.

Our industrial model is a combination of end-use features and econometric features.

So, for example, to project energy use for the chemical subsector, or the paper subsector, it's based on projected output in those subsectors, changes in rates, as well as end-use energy intensities, where end-uses in the industrial sector include things like motors, and lighting and HVAC.

For our agricultural model we use a disaggregate econometric model, meaning we're projecting down to the subsector level for agricultural, meaning we're projecting separately for dairy and livestock, and crops and irrigation, and urban water pumping.

Transportation, communications in the utility sector, for example radio and television, support activities for the airline industry, support activities for rail, we call that the TCU sector. And that's forecasted using a disaggregate trend analysis, as is street lighting.

And our sector results for consumption feed into our summary model, where results are aggregated and calibrated to historical consumption.

And the summary model provides input for our peak model, which takes end-use consumption, applies load shapes, and provides an annual peak demand number for each planning area.

Later on today we will also hear about the predictive models we've developed for self-generation or on-site distributed generation.

As I mentioned, we also do a forecast with more aggregate econometric models. We have separate models for all the individual models both for electricity and natural case, except in the case of TCU gas where I couldn't find a -- the data we had, I couldn't estimate a model that logically made sense and had significant explanatory variable coefficients.

So, for TCU gas, for the econometric forecast, we're actually using the trend analysis that's used in CED 2013.

And we have an econometric peak model. And we use these econometric models to inform our forecasts. For example, price elasticities estimated in the econometric models are used in our end-use models.

We use the econometric models to make adjustments. For example, impacts of climate change are estimated to our econometric models and applied to the forecast.

And as a point of comparison, as I mentioned, I will be comparing the two forecasts a little bit later.

And as we go from forecast to forecast we attempt to improve and refine our methods. So, here's what's new for this particular forecast. We have a new industrial model. Up until this forecast we've been using what's called INFORM, the industrial forecasting model that was developed in the 90s by EPRI.

And the idea behind this model was there was going to be a user's group to support the model and allow us to make refinements and improvements, but that all sort of fell apart with restructuring in the late 90s. So, we were left with this model that had no support and we didn't have the computer code for, so it's difficult to make changes and improvements in the model.

So, what we're doing is we're in the process of rebuilding the same basic methodology from the ground up.

So, this is still under construction. However, we made enough progress that we felt we could use it for this forecast.

To fully utilize this model what we really need is a new industrial survey, which hasn't happened for a while, because we've had to make sort of simplifying assumptions for this forecasting for trends in energy intensity in the industrial sector.

In the last -- oh, econometric models used in the 2011 forecast were re-estimated and we've now added new econometric models to cover all the sectors that weren't covered last time. With the exception, as I said, of TCU gas.

In 2011 we estimated peak impacts of climate change. For this forecast we're adding estimated climate change impacts on electricity and natural gas consumption.

New efficiency programs and standards to account for, including the 2013-2014 IOU programs, 2013 POU programs, and new standards that have been finalized since the 2011 forecast, the 2013 Title 24 Buildings Standards update and the Battery Charger Standards.

We're doing our analysis at the climate zone level. And you'll see some results later when we talk about the planning areas. And also a little later you will hear about our new predictive model for commercial CHP.

We provide three scenarios, high demand, low demand and mid demand. And high demand is characterized by higher economic and demographic growth, lower program impacts, lower rates, higher climate change impacts. Basically, we're rigging the scenario to get higher demand.

In the low demand case it's the opposite, except for climate change impacts, which are not included in the low demand case.

In the mid demand case we have assumptions in between the two, in the high and the low. And there are climate change impacts included, although not as high as the high demand scenario.

For our economic scenarios we used, for the high demand case what Global Insight calls their optimistic case.

For the mid demand case we used Moody's economy.com baseline case, or most likely case.

And for the low demand case we used a combination of two scenarios that combined a mild recession in the short term, although not nearly as bad as what we saw in 2008, along with another scenario that projected lower long-term growth.

Important inputs that go into our forecasts, of course, population. Average household size, when you combine that with population that gives you projections for a number of households which is critical to our residential forecast.

Our commercial floor space forecast or input is actually derived input. It comes from regressions using economic and demographic data.

So, for example, projections for retail floor space are a function of population growth and expected growth in retail employment.

And rates, and as we'll hear about today we have a pretty high rate forecast, and that's really making the most difference between our forecasts and what the utilities are showing since we have much higher rates.

So, finally, some results. This is electricity consumption in gigawatt hours for the State as a whole, the sum of individual planning areas.

And you'll notice a couple of things here. Our reference, in red there, is the mid case from the last forecast. And as you go from 2012 to 2013 in the new forecast you see that it's flat.

And in our new mid demand and low demand cases we show lower growth over the forecast period versus the 2011 mid case.

The same basic pattern for peak demand, this is a non-coincident peak demand meaning it's simply the sum of planning are coincident peaks that may occur at different times and different days.

Again, it's flat from 2013 to 2014 and then less growth in the high and the low -- or the mid and the low case relative to the 2011 mid case.

I show here a weather normalized peak. As the reference point or the starting point we weather normalized the last historical year. So, that means assuming historically average temperatures.

And you’ll see that our weather normalized peak is very close to the actual peak in 2012. So, what that means is that in terms of the highest temperatures we had a fairly average year in 2012.

Okay, so what’s going on here? Flat growth from 2012 to 2013 and we have a couple of things causing that. First, we have a significant increase in electricity and natural gas rates. And the increase in electricity rates I believe is over a penny per kilowatt hour from 2012 to 2013.

We have the introduction of the 2013-2014 IOU programs in 2013, along with new POU programs, which pushes demand downward.

And in 2012, unlike the peak case we have, in 2012, a historically warm year in terms of cooling degree days. So, even though the high -- looking at the highest temperatures it was a fairly normal year. For cooling degree days, overall 2012 was a warm year.

Now, when we go in the forecast period, when we go from 2012 to 2013 we’re reverting to historically average weather. So, you’re going from a relatively warm year in terms of consumption to a historically average year, and that means less demand all else equal, less weather impacts.

Yes?

MR. STEVENS: So, when you say 2012 was a warm year do you mean kind of throughout the summer, is that what you mean? Because I know in terms of the peak they say it was kind of a one in two summer.

MR. KAVALEC: Right. Yeah, so one in two -- so, meaning for peak, which is determined by your highest temperatures, it was a fairly normal year, or one in two year.

MR. STEVENS: Okay, gotcha.

MR. KAVALEC: In terms of degree days, what that means is you take a reference temperature, like say 65 degrees, and over all days of the year you add the average temperature on that day or you subtract 65 from the average temperature on that day, over all days of the year.

So, the warmer year it is on average, the more cooling degree days you're going to have.

And that's a fairly standard use, heating degree days and cooling degree days in weather type analysis.

Also, I should mention that economic growth in terms of income was lower from 2012 to 2013 than it had been projected in 2011, another reason that we're starting out relatively flat in the forecast.

For lower growth, the reason we have lower growth in the mid and low scenarios versus the 2011 mid case, number one lower population growth relative to the mid case in 2011, as I'll show you in a minute.

Higher rate increases versus the 2011 forecast. And we have the inclusion of a couple of additional sets of standards that weren't included in the 2011 forecast, as I mentioned, the Title 24 Building Standards update and the Battery Charger Standards.

Okay, this shows electricity consumption per capita, starting in 1990 and going through the forecast period.

Consistent with what we saw with consumption, we have a drop in per capita consumption from 2012 to 2013.

And then the mid and low cases are flat or declining throughout the forecast period until the very end, where the increase in the number of EVs pushes up electricity consumption per capita.

Overall, we're -- you know, we have some ups and downs here but it's pretty flat, especially compared to U.S. per capita consumption. But we do have periods where it goes up and periods where it goes down.

So, you can see, for example, shortly after the recession in 2001, basically from that point all the way to 2007 or '08 per capita electricity consumption was increasing. So, during times of economic boom, despite efficiency and other policy efforts, per capita consumption has been increasing and then, of course, declining during economic downturns.

So, it will be interesting to see if the economy starts chugging along at a high rate of growth, which will hopefully happen relatively soon, whether electricity consumption per capita increases as it has in the past or have our efforts -- will our efforts related to efficiency wrestle that increase to the ground so that it remains flat.

Natural gas consumption, the same basic story, flat or declining from 2012 to 2013 for the reasons, the same reasons as consumption.

And in addition, natural gas consumption is affected by -- that should say reduced heating contributes to flat growth.

So, with the incorporation of climate change you have less heating degree days, so that means less heating being needed, so that drives down natural gas consumption relative to what we had in 2011.

And the three scenarios are fairly close together, you'll notice, because the high case has more climate change impacts than the mid case, which has more climate change impacts than the low case. The net result is that it pushes the scenarios together.

Probably the most important input that we're talking about today is population. We used three different scenarios, shown here, a high, a mid and the low. The high case comes from Moody's, the mid case from Global Insight, and the low case from the California Department of Finance.

And what we used last time for the mid case is basically it's similar to what we're using this time for the high demand case. In other words, our 2011 mid case population growth is higher than it is in this forecast for the mid and low demand cases.

I mentioned earlier little economic growth from 2012 to 2013 in terms of personal income, and the affect that has on consumption and peak. And you see that here with the three scenarios for personal income.

We're flat in the first couple years in the low demand case, we're flat in the first year of the forecast for the mid and the high cases.

Our natural gas rates, electricity and natural gas rates. Relatively higher rate growth this time. Let's start with natural gas here. These prices were -- oh, by the way, these rates are sales-weighted sales averages, an average of the individual planning area rates.

So, for natural gas you'll see very -- the highest rate growth. In the low demand case, which means higher rates, we're almost doubling natural gas prices between 2012 and 2024.

These prices were developed by the Supply Office here at the Energy Commission, which uses a model known as the North American Gas Trade Model, or NAMGAS for short.

So, they developed these scenarios for us and these are, admittedly, preliminary scenarios, with a relatively new model.

And they received a lot of comments. They presented these prices back in February and there was concern then about the level of price increase. They will provide a new set of prices for a revised forecast and it could be fairly different from what we're seeing here, but we'll have to wait and see.

The electricity rates were developed using the E3 GHG rate calculator. So, in that rate calculator you're inputting assumptions for demand, photovoltaics, CHP, natural gas rates and it spits out predictions of rates for each of the major planning areas.

So, our rate increases, which are higher than we've had in the past for electricity, range from around 30 to 50 percent.

What's happening is basically we have high natural gas rates, as you see here, and you combine that with assuming policy goals are met for PV and for renewables, and you have a cap and trade in place, and what you're going to get from the model is relatively high rates. That's what's going on here.

And, of course, we will reevaluate our rate projections for our -- for the revised forecast using whatever the latest available information is from the CPUC and from the utilities.

And we'd like to hear from the utilities what their views are in terms of expected rates in the next ten years, this afternoon.

Okay, on to efficiency. Traditionally, in our forecast we have only included what we call committed efficiency impacts. That means impacts from programs that have been funded and approved. So, the 2013-14 IOU programs, as soon as they were finalized and approved became committed impacts in terms of our forecast, finalized and/or implemented standards and price effects.

So, in the past we have included committed impacts, although we realize there are additional likely to occur, efficiency impacts that we refer to as uncommitted impacts.

For example, IOU programs after 2015, since they haven't been designed and funded, yet, we would call that uncommitted impacts, but they are reasonably likely to occur.

So, as I mentioned, after this forecast we're going to be developing scenarios with Navigant for incremental, uncommitted efficiency that's going to feed into our revised forecast. And these scenarios are going to be designed with input from CPUC staff and CAISO staff. And we can, hopefully, all three agencies work together to develop one or more incremental uncommitted efficiency scenarios that we can agree on.

There's still the nagging issue of what to call these darn things. So, the last time I floated out "achievable" which didn't seem to take. Although, I noticed Mr. Casey used the word "achievable."

Others have suggested "incremental" without uncommitted in the name.

And more simply, "projected efficiency." So, hopefully, by the time of the revised forecast we can reach some consensus on terminology here.

This shows our estimates of committed efficiency savings, going back to 1990. The benchmark here is 1975, so the reference is, for example, usage and efficiency levels for air conditioners built in 1975, for refrigerators built in 1975, and so on.

By 2024 we have over 100,000 gigawatt hours' savings coming from standards, from programs and price effects.

You'll notice that scenarios are close together here. And what's going on is we have two sort of effects working in the opposite direction within the scenarios.

In the high demand case you have more new construction and, therefore, more savings from standards.

In the low demand case you have less new construction, less savings from standards. However, you have more savings from price effects, higher rates, and from more efficiency programs. And the net result is that it pushes the scenarios together, as you see here.

I always like to give a caveat for this. What this is meant to represent or estimate is how much higher consumption would be in a given year had we done nothing in California, in terms of standards and programs since 1975, and there had been no rate changes.

But that's -- it's not totally realistic because without standards, programs and rate changes there probably would have been some changes naturally occurring in the market. Some appliances would have become more efficient for competitive reasons, and so on.

So, this may overstate the total amount of savings but this is, for now, the best estimate we have.

This shows our estimates of the 2013-2014 IOU program savings for the mid case. This shows the savings for the IOUs combined, as well as the individual IOUs.

So, 2013 and 2014 we're adding in first-year savings and after that point, at the end of the cycle, the savings begin to decay away.

What determines decay is expected useful lives of the individual measures included here applied to an exponential decay function.

And what that means in more simple terms is that most of the decay or the burnout occurs around the end of the expected useful life of the measure.

An adjustment was made to decay to be consistent with the CPUC's direction in 2009 that 50 percent of decay needed to be -- was required to made up for by the utilities with new program activities. And I believe that's still the law of the land.

So, we assumed away 50 percent of the decay here to be consistent with the CPUC directive.

So, this is the mid case, as I mentioned. Our high demand or lower savings case is 10 percent lower and our low demand, higher savings case is 10 percent higher. And that 10 percent is sort of a semi-scientific number that was estimated by Navigant, doing scenario analysis for the potential study, efficiency potential study in 2011.

So, they tweaked various inputs, like economic growth and rates, and found that at a maximum the program savings or potential program savings would increase or decrease by a maximum of 10 percent, so that's how we came up with this number.

For publicly-owned utilities we have 2013 programs. So, we have first-year savings in 2013 that decay away after that year.

This shows the two biggest POUs, LADWP and SMUD, along with the total for POUs.

We don't have -- oh, one more thing about the IOU programs. In the past we've typically adjusted IOU reported savings downwards using some realization rate because there's evidence that in the past reported savings are higher than what has actually occurred, or I should call it predicted savings, not reported savings, for 2013 and 2014.

However, for this program cycle the IOUs develop their predictions for savings taking into account realization rates estimated in the 2006 to 2009 EM&V studies, and the latest DR data. So, we felt comfortable using, in the mid case, the savings reported or predicted by the IOUs as is, without making any further adjustments.

And for the POUs, we don’t have that EM&V-based confidence in the reported savings or predicted savings. So, for the POUs what we did in the low demand case was apply realization rates for efficiency programs estimated in the 2006 to 2009 CPUC EM&V.

And in the high case we used reported savings as is.

The mid case uses realization rates in between the two, the high and the low.

The upshot is we end up, coincidentally, with a mid-case and a high savings case 10 percent higher and a low savings case 10 percent lower, but for different reasons.

We also have natural gas program savings for the IOUs that we handled the same way, and those reach 80 million therms in 2014 and decay to around 70 million by the end of the forecast period.

Our new standards save us a couple gigawatt hours by 2024.

On natural gas, the Title 24 Building Standards update save us an additional 50 million therms by the end of the forecast period.

Half of the new electricity savings that I showed you in that early graph, in the forecast period, are coming from price effects, which is not surprising given the sharp rate increases that we have in the forecast.

Okay, onto climate change. Basically, what we're doing here is we're taking temperature scenarios and using our econometric models estimating the impact of these temperature scenarios, where average temperatures are increasing, on electricity, peak demand, and electricity and natural gas consumption.

So, these scenarios that we use for temperatures come to us from the Scripps Institute, under contract to the Energy Commission. And they have -- they ran for us ten different climate change models, with two scenarios each for a total of 20 scenarios.

And what we did was to take a scenario toward the high end for the high demand case, and a scenario in the middle in terms of temperature increase for the mid demand case.

So, they're providing output or results down to a 50 square mile grid area in California. So, what we did is to take the scenarios that correspond to the weather stations that we use in our forecasts.

So, for example, for SMUD we used the grid that corresponds to Executive Airport, which is our weather station for SMUD.

For the Riverside climate zone, a portion of Southern California Edison, we used the grid area corresponding to Riverside Airport, which is our weather station.

So, for electricity consumption we estimated changes in heating and cooling degree days based on these temperature scenarios and apply that in our econometric models where cooling and heating degree days are an explanatory variable in the regression.

Natural gas consumption impacts through -- are estimated through changes in heating degree days, so less heating project for natural gas consumption because of climate change.

And our peak impacts are estimated through changes in the annual maximum daily average temperature.

So, this shows, for electricity consumption, the impacts of climate change in the mid case. We have to effects, opposing effects going on here. The green line shows, the top line shows the impact when you consider only the increasing cooling degree days on consumption.

However, there is a decrease in heating degree days, which is going to bring down consumption, okay. The net effect, increasing cooling degree days, decreasing heating degree days puts you at the blue line there, the bottom line.

So, by 2024 we have around 1,250 gigawatt hours additional consumption due to climate change in the mid case.

At the high case, the corresponding numbers would be 2,400 gigawatt hours in 2024 from the increase in cooling degree days, and a net impact in 2024 of around 1,800 gigawatt hours.

For natural gas, this is a decrease in consumption shown here because of less heating degree days.

In the high demand case we reach over 600 million therms less consumption because of climate change and in the mid demand case around 250 million therms in 2024.

Percentage-wise, natural gas consumption impacts are higher than they are for electricity and that’s because heating is such an important end use in natural gas.

Here’s our peak demand impacts, at the statewide level this shows the results for the five major utilities, along with the State total.

So, for the State as a whole, in 2024, we’re estimating an increase of around 1,000 gigawatt -- or

1,000 -- no, that should be megawatts, sorry about that, around 1,000 megawatts higher in the mid demand case and 1,700 megawatts higher in the high demand case.

And this also shows the changes in temperatures projected in our climate change scenarios from Scripps. And the temperature we’re using here is the annual maximum daily average temperature in 6-3-1 form, meaning we’re taking 60 percent of today’s temperature, 30 percent of yesterday’s, and 10 percent of the temperature the day before.

In the mid demand case we’re getting, for that temperature index, an increase of a little bit less than one degree over the forecast period.

And in the high demand case we’re getting an increase of around one-and-a-half-degree days, one and a half degrees over the forecast period.

Okay, comparing our CED 2013 preliminary forecast results, which I’ve been showing here, with our alternative econometric forecast, for statewide electricity consumption the econometric model gives us projected consumption two and a half percent higher in 2024, than in CED 2013.

For the peak, the econometric forecast is 4.5 percent higher in 2024.

And for natural gas consumption it’s a whopping

9 percent higher in 2024.

So, what’s going on here? Three things, I think. The first has to do with efficiency. In the econometric forecasts we didn’t account for efficiency, explicitly, unlike in the CED 2013 end-use forecasts.

The econometric models are based on historic data that goes back to 1980. So, I believe that these econometric models, although capturing the efficiency trend and projecting it out, since it goes back to 1980 it’s projecting an average trend that is much lower than the trend we’ve seen in the last ten years.

Okay, because we know that since 1980 there have been periods where there wasn’t much going on efficiency-wise, and energy efficiency efforts have intensified in the last ten years.

So, I maintain that the econometric models understate efficiency impacts and, therefore, overstate the projected consumption.

Yes, a question.

MR. FERRON: Just a question, what are the variables that go into the econometric model, is that listed somewhere in this presentation?

MR. KAVALEC: Well, not here, unfortunately. But the full estimation results are available in our report. So, the variables used depend on the sector.

So, for example, the residential econometric model includes per capita income, weather variables, unemployment rate, a couple other ones.

MR. FERRON: Okay.

MR. KAVALEC: Okay, so that’s one thing, one important factor.

The second thing is that -- has to do with the price elasticities. I mentioned before that we transfer some of the price elasticities that we estimate in our econometric models to our end-use models, but that the exception to that is the commercial end-use model.

And the reason we didn’t transfer that price elasticity is that the commercial end-use model requires price elasticities down to the end use in building type level, okay.

The average commercial price elasticity in the end-use model is around 15 percent. In the econometric model it’s around 2 percent. So, price elasticity is measuring a percent change in demand for a given percent change in price.

So, it’s much higher in the commercial end use model and that makes a big difference when you have sharply increasing rates, as we do in this forecast.

So, I estimated that fully half of the difference between the econometric and CED 2013 forecast comes from this difference in commercial price elasticities.

The third difference pertains to natural gas. What we call our mining sector is actually a combination of construction and resource extraction. And in the econometric model these are combined together, aggregated into one variable for consumption, whereas in our industrial CED 2013 forecast they're projected separately.

In our economic scenarios, all three of them show a sharp decline in resource extraction output in California. That decline is fully captured with a more disaggregate methodology, as in CED 2013, compared to the case where you have resource extraction combined with another sector, construction, okay.

So, the econometric model doesn't fully capture, in other words, the decline due to reduction in resource extraction output over the forecast period.

COMMISSIONER MC ALLISTER: Hey, Chris, just a question. So, I guess I'm wondering, so I'm sure there are challenges to, you know, tweaking the econometric models to account for some of this stuff, but it strikes me there probably are some techniques to sort of -- I guess, maybe you could talk about the challenges of, you know, trying to capture the recent efficiency trends and, you know, setting up the regression so you can kind of do that and detect, actually, in the data the sort of difference between the old and the new trends.

You know, I'm sure you've got some data limitations and of the like, so maybe you could talk a little bit about that. Yeah.

MR. KAVALEC: Okay. Yes, it comes down to data limitations, basically. I've attempted to do this in the past, but you get a very weak correlation between efficiency program spending, for example, and electricity consumption.

And that's because up until very recently it's been pretty small in terms of total consumption, so it kind of gets lost in the noise.

So, I'm hoping as we move along and we have more years of efficiency program data and impacts to work with we will begin to -- we'll start to be able to capture this within our econometric models.

COMMISSIONER MC ALLISTER: Also, I would just point out, so thank you, you know, it seems to the extent that there are multiple effects on any given project, say, so price elasticity, so they're -- so, you've got price effects which seem -- you know, are obviously a big driver. So, you get prices going up and somehow the customer's reaction to those prices is going to be either turn the lights off more, you know, sort of basically forego some service because it’s now too expensive or, you know, sort of traditional conservation, let’s call it, or you’re going to say, okay, well, now, boy, prices are high and now I’m going to install that lighting, or now I’m going to install a bunch of widgets, or do a whole-house retrofit, or whatever it is.

So that, the expression of getting to that lower demand could take several pathways. Some of them go through programs and some of them don’t and I think it’s kind of important to appreciate that going forward. I think the Navigant -- so, to the extent that that’s sort of the installation or, you know, the actual project-based savings would potentially be -- would probably be expressed through the Navigant work and some of the forecasting on sort of the more technically-based forecasting and less on the behavior.

But I guess I just wanted to sort of point that out that the pathways to having reduced demand are numerous and probably complementary in many ways.

MR. KAVALEC: And I’ll also add to that, I showed earlier a graph that provides estimates of total efficiency impacts from the three sources, programs, standards and price effects.

And one problem we've dealt with in the past is attribution of savings to the different sources because we know there's overlap between the different sources.

Programs sometimes are designed to ease, pave the way for standards. Customers are more likely to take part in incentives programs as rates go up, and so on.

So, I guess my point is you run into the overlap problem when you try and isolate individual efficiency impacts because they're working together.

COMMISSIONER MC ALLISTER: Okay, thanks.

MR. KAVALEC: So, I always like to try and add something, a little tidbit that's, hopefully, interesting in my presentations.

In our economic/demographic workshops we have talked about, we have heard discussion about this last recession as being kind of unique in the sense that it was a financial recession. But however you characterize the recession, it's definitely had impacts on energy demand.

So, I attempted to incorporate some of these "non-traditional" financial variables into our econometric models.

So, for the residential model I included or I tested the impacts of foreclosures, bankruptcies and median home price, and found that the variable that gave me the most significant coefficient was median home price, okay. Positive relationship, as median home prices rise, people use more energy.

So, what I've shown here is the impact from the housing prices during the boom and the bust period on electricity consumption for the State, as a whole, isolated from other economic effects, for example income or the unemployment rate.

So, we start out in the year 2000, where home prices begin to rise, until the median home price is almost double by 2006, and the impact there is around 800 gigawatt hours for the State, as a whole.

And then we reach the bust part, prices start to go down, foreclosures go up, and there's less electricity consumption, all else equal.

And we end up in 2012 in terms of home prices basically where we were in 2000.

So, what this is illustrating, I think, is the wealth effects and the impact that they have on electricity consumption.

So, as the key asset that you own increases in value, you become more wealthy, so you can borrow on your house, buy new toys that use more energy, build additions to your home, and so on.

But then when the median home prices start to drop or your home price starts to drop you're losing wealth, okay. And all else equal, you're going to consume less energy.

MR. CASEY: I have a question on that. It seems like looking at average income or unemployment rates might be a more direct way to get at that effect. Is that something you've looked at, as well?

MR. KAVALEC: Yeah, the variable that was introduced was median home price divided by average household income in that year. So, I attempted to account for the fact that incomes are changing at the same time as median home prices are changing.

And as I mentioned, I attempted to isolate this impact. So, also in the econometric model you have coefficients for income, and the unemployment rate, and other variables. But this is, hopefully at least, isolated to the impact from home prices on the electricity consumption.

Okay, in closing here's what we're working on for our revised forecast. We've discussed incremental uncommitted efficiency that we're all going to work together on, or whatever it is we end up calling it.

For this preliminary forecast we used the electric vehicle forecast developed in 2011 because we didn't have a new one.

For the revised forecast the Fuels Office is going to provide us a new electric vehicle forecast that will be incorporated in our revised forecast.

They're also doing analysis to estimate additional electrification in the State, in the ports, and truck stops and so on, in addition to estimates for electricity use by high-speed rail in the next ten years. So, that will all go into our revised forecast.

We've incorporated climate change into consumption and peak demand, but there's also a potentially important issue and that is the effect of climate change on temperature distribution. And an average peak, quote average peak versus a peak demand in a more extreme year.

In other words, is climate change going to affect the distribution of temperatures? Are extreme temperatures going to become more extreme relative to the average?

And this is important because for some analysis that this demand forecast is used for, for example resource adequacy, the important metric or output is one in ten peak demand not one in two peak demand. So, the relationship between one in two and one in ten is being explored by both us and Scripps and, hopefully, we'll have something to report and incorporate in the forecast in the revised version.

We haven’t talked about ARRA, yet. Staff doing the ARRA analysis in the Energy Commission have promised us estimated impacts to include in our revised forecast.

And as always, we revise our economic demographic data. Moody’s and Economy.com provide monthly updates for their econ demo data, so we’ll be updating our econ demo data for the revised forecast as well, as I mentioned, we’ll be reevaluating our rates. So, we’ll probably have a different rate forecast for the revised version.

And I guess that’s it. So, with that I’ll ask the dais for comments or questions.

COMMISSIONER MC ALLISTER: Thanks for that, Chris. That was very helpful.

I guess I just have one question I’ve been kind of noting down and I meant -- there were a bunch of questions that I had and then you promptly answered in your presentation, so I have a fairly economical list here.

I guess on the natural gas, you know, those percentages look high, as you pointed out, as far as price escalation over time. But it seems to me we’re starting at a pretty low base, so I just wanted to kind of ask about the baseline there and, you know, sort of 69 percent on top of what, right? So, just high is relative historically, right?

MR. KAVALEC: Right. And the last couple of years we've had close to historical lows we've had close to historical lows.

COMMISSIONER MC ALLISTER: Yeah.

MR. KAVALEC: Yeah, that's a good point. Percentage-wise it's a big increase. In absolute terms, however, we're starting at a fairly low price.

COMMISSIONER MC ALLISTER: Yeah, and so it's --

MR. KAVALEC: In historical terms, the price you end up with not that high.

COMMISSIONER MC ALLISTER: In our discussions, you know, with the forecasting team I've just noted, and with the natural gas team, you know, I think what they struggle with, rightfully so, is how do you -- you know, given the fact that we're in kind of an historical anomaly and we've got this kind of new, brave new world with respect to gas supply, it's pretty hard to -- I mean you never know what's going to happen, but it's really hard to know what bounds to use going forward. So, I think that seems like a challenge across the board, certainly for forecasting.

MR. KAVALEC: It is.

COMMISSIONER MC ALLISTER: And the price, the high prices, the sort of high prices are relative to where we're starting today, which is quite a low price, so I think that's important to kind of keep in mind.

Yeah, I'll stick with just that question for now and ask anybody else if they have a question.

COMMISSION CHAIRPERSON WEISENMILLER: I've got a couple. The first one, Chris, is probably, you know, to make sure that we get PUC input on the rate forecast.

For those of -- I think when we have our initial discussion, I believe Commissioner Florio was here. But anyway, one of the things, we're relying -- obviously, both of you, all three offices struggled a lot with what are rate impacts going on in the future.

We are relying on a model that E3 developed for the PUC in this analysis. Now, at least I think the last time some of the energy division people looked at us like what model?

So, anyway, as you can tell the rate number has a big impact on growth and energy efficiency, and so we need to make sure that that's one which has been ground truth pretty seriously with the PUC.

And again, you get to whatever -- again, this is a baseline number.

I think the other part of the conversation, probably when we get more into the self-gen forecast, is certainly rate design, that metering can have big impacts there.

So, again, we’re going to need to all scratch our heads on what’s going on there, which will have pretty significant impacts on your DG forecast.

So, I wanted to just flag that and encourage whatever -- you know, whoever the PUC’s experts are on rates, really work with Chris and folks as part of the process so we’re aligned on that.

I think the other question was going to be in the 70s, when we were struggling with whether to do disaggregated forecast versus econometric, we went towards disaggregated because we thought energy efficiency was a real structural change and we could not capture the energy efficiency impacts with, you know, an econometrics model.

Well, in fact, we do have a pretty good history, now. As Chris said, you know, it’s not the full term. But, presumably, in the econometrics there is some baseline amount of energy efficiency.

But the things that we struggled with at the time, the utilities argued a lot that the problem with an end-use forecast was that it was not going to consider future electricity uses, and they used the term “phantom appliances”.

And now as they come back into this field saying, well, let’s see, in fact in the 80s we didn’t think about computers, set-top boxes, you know, the whole proliferation of stuff in your household.

And so, one of the things we always have to struggle with on the end-use model is to really take into account those new, miscellaneous things that occur, which may or may not be embedded in the econometric model, so that could be part of the delta.

I don’t know, Chris, have you thought about that, how to capture that?

MR. KAVALEC: Well, in general terms what we need to do to keep up on electricity and natural gas demand on an end-use level is get back into our large-scale surveys. That’s going to provide us the data.

In terms of capturing end-use elements with an econometric forecast, that can be done to a certain degree, the more years of data that you have.

And so, I’m hoping that in the next round, as I re-estimate these models I do it with -- I can get data more frequent than once a year, quarterly or monthly data, and that should be able to tease out, to a greater extent, impacts, end-use and efficiency impacts within an econometric model, I’m hoping.

COMMISSION CHAIRPERSON WEISENMILLER: Well, that actually -- you sort of anticipated my last question, which was for some sort of commercial message on the end-use surveys.

Obviously, as we go forward we're always struggling with these are relatively expensive, but they do provide the foundation for the forecast.

And I know one of the things we've been struggling with in the last couple of years is trying to get funding for those.

So, Chris, do you want to give us just some background on what types of dollar amounts we're talking about, what types of surveys and frequencies. And when was the last time we did them, really.

MR. KAVALEC: The last survey we did was the residential, the RAS survey in 2009.

The Title 20 legislation was intended to have a survey for each sector done roughly every four years, so you're kind of alternating one year -- or one two-year period you're doing a residential, then you're doing a commercial, then you're doing an industrial.

And we were cranking along pretty good until we hit restructuring and then, like a lot of other things, that kind of fell apart and it never really got restarted to the same extent as we had before the --

before the restructuring.

In terms of dollars, well, you know, I was going to say a few million, but once you start talking about further disaggregation, going down to a much more granular level, you're probably getting into the $10 million to $20 million area per survey.

COMMISSIONER MC ALLISTER: I want to just pile on a little here because that's a terrific question and point that Chair Weisenmiller made.

And my understanding is that the last CEUS, the Commercial Survey, was like 10 years ago, now, 9 or 10 years ago, now. You know, which there have been many changes in the commercial sector over that period and it's really unfortunate that we don't have more recent data than that. So, that would be sort of the -- yeah, could you maybe talk about the -- so, we've got CEUS, RAS, and there's an industrial one as well, somewhere along the line, right?

MR. KAVALEC: Yeah, there's an industrial survey and since I've been at the Commission one hasn't been done. I think one may have been done in the early 90s.

COMMISSIONER MC ALLISTER: At risk of asking how long that is --

(Laughter)

COMMISSIONER MC ALLISTER: So, '95, when did you come to the Commission, Chris, you know --

MR. KAVALEC: Oh, okay, sorry.

COMMISSIONER MC ALLISTER: And how much do you weigh? No, just kidding.

(Laughter)

MR. KAVALEC: Yeah, I would say at least 20 years.

COMMISSIONER MC ALLISTER: Yeah, okay, great. Wow. Yeah, commercial is -- I think it was like ’02 or ’03, or something when the last one was done.

MR. KAVALEC: It was started in ’02 and was finished in ’04, yeah.

COMMISSIONER MC ALLISTER: Yeah, okay. I guess I would just -- and I don’t want to hog the microphone here, but I think there are -- in some of the other things that I’m doing at the Commission, and there’s a lot of synergy with what’s going on with the IEPR, I think there really are a lot of interesting data tools that are coming up. I mean it’s enabled -- a lot of it is enabled by the Smart Meters, but not all of it.

I think lots of discussion about that. I don’t want to sort of tread -- I want to tread lightly here. But I feel that to the extent that there are tools for characterizing demand at a granular level and then figuring out how to then take that and create knowledge that informs the forecast, I think there's a lot of really amazing potential coming up here quickly.

How we make that happen, how it gets paid for and who drives it I think are open questions.

But I want to just point out and I'm sure the PUC Commissioners have more concrete knowledge of this and what's going on at the utilities, but I think that actually could provide -- it could kill a lot of birds with a limited number of stones.

And I think thinking about that as at least getting us partway, where traditionally we would have had to go with surveys is -- potentially, it's more cost-effective and actually more effective, generally.

So, surveys are expensive, they're very time consuming, they take a long time to get done and they have some limitations. And I think we could get past some of that stuff with some of these new data tools.

So, anyway, with that I'll pass to others on the dais.

MR. CASEY: Chris, just a couple of questions. On the slide you had on energy savings for the investor-owned utilities, you mentioned the decay rate was adjusted by 50 percent to account for new programs making up that difference.

And I was just curious how that adjustment gets reconciled with the ongoing effort on the uncommitted energy efficiency savings. Is that effectively an assumption about uncommitted energy efficiency or --

MR. KAVALEC: No, it's not meant to me. It is new programs that aren't currently installed, but it's meant to fill the void lost by decay or committed savings.

MR. CASEY: Okay, but do those new programs have funding or --

MR. KAVALEC: The mechanics of how that's done I think is maybe a question for CPUC Energy Division staff.

MR. CASEY: Okay.

MR. KAVALEC: My only knowledge of it is that utilities are responsible for making up half of the decay that occurs in their committed programs.

MR. CASEY: Right. Well, maybe just more of a comment that as we look at the uncommitted energy efficiency, we ought to look at that assumption and how that factors in to the assumptions around uncommitted energy efficiency.

MR. KAVALEC: Okay.

MR. CASEY: The other question and it kind of builds off of Chair Weisenmiller's comments about the energy saving associated with price effects, and it gets to adoption of, particularly, rooftop solar for residential sector. And I'm just curious how much of the econometric model for the price effect reflects the fact that, you know, conditions are much more favorable for adoption of rooftop solar.

And, you know, you certainly have the theory out there of the death spiral as rates go up, particularly in those upper tier ranges it's going to create a huge incentive for rooftop solar, and then your rate base is going to decay, and rates will go even higher.

So, I'm just curious how much that got factored into the analysis that you've done.

MR. KAVALEC: Well, as we'll see this afternoon, the rate increases have a significant impact on adoption of photovoltaics, as well as commercial CHP. So, that gets factored in through our self-generation or on-site distributed generation predictive models, which use rates as an input.

MR. STEVENS: Do any of these forecasts take into consideration potential increases in technology, especially in terms of storage and distributed storage?

MR. KAVALEC: No, for us that's more of a supply side type issue.

MR. STEVENS: I see.

MR. KAVALEC: We're just all about pure demand, how much we're going to need.

MR. STEVENS: You know, my thoughts are that, kind of along with what Keith was saying is that as storage becomes more prevalent, and the technology improves, and small-scale solar becomes more cost effective, we do see that death spiral or whatever you want to call it, a massive change in the market. And I was just curious if that was taken into consideration at all?

MR. KAVALEC: Not directly.

MR. STEVENS: Okay.

MR. KAVALEC: At least at this point.

MR. FLORIO: Yeah, on the issue of rate forecasts, I think when Commissioner Ferron and I got to the Commission we were both a little surprised that that wasn't happening anywhere, and we've tried to build up that capability. It's still a work in progress. I wouldn't say we have anything publication worthy.

But you look at these numbers and you compound it over 12 years, a 40 percent increase in electricity rate sounds like a lot, but over 12 years that's only around 3 percent compounded.

I cannot recall off the top of my head exactly what the figure was in the work our staff did, but I don't think it was significantly off from that. It was probably a little bit lower, but I'm reasonably sure our forecast did not have the same increases in gas prices. And if you assume higher gas prices, you're going to get higher electricity prices.

In fact, if I recall correctly, our staff even discounted the utilities' gas price forecasts a little bit. So, you know, we're still kind of feeling our way on this but, you know, I don't think cumulative 3 percent or so a year is widely out of whack.

And, you know, the gas price is still a huge factor so, you know, a lot of unknowns. In some ways, you know, we've managed to keep roughly to the rate of inflation over the last ten years or so, but that's in a period of declining gas prices.

So, if that does level out, we may be looking at more significant impacts.

MR. KAVALEC: And as I said, we'll reevaluate our rates for the revised forecast and they may go down, but we're not going to be anywhere near flat or nearly flat rates as we've had in some of our past forecasts, just because of all of the policy requirements and activity going on.

MR. FERRON: and just to respond to that, that point. I actually dug up the numbers that we were playing around with, while we were sitting here, and they are slightly more benign. And I think part of that has to do with the natural gas forecast. Although, there was not consistency between the different utilities in terms of those assumptions and that was what made the exercise that much more difficult.

The other observation I'll make is just doing arithmetic on the forecast numbers here for changes, the percentage, annual percentage compound growth is assumed to be much greater in the short term and tapers off over time, which maybe that's just a function of the math.

Intuitively, it seems as though the shape of the curve would be the other way around that we may see accelerating prices further out as -- as deeper penetration occurs, more transmission upgrades, et cetera, et cetera.

But the ranges are around, if you take the mid case, between less than 3 percent up to 4 and a half percent.

Well, actually, the PUC analysis and the CEC analysis were within the same ball park.

MR. KAVALEC: Okay, I guess we have time for a couple of questions, just a couple of questions from the audience, if there are any.

MS. GANGOPADHYAY: Hello, this is Monisha from DRA. Can everyone hear me?

MR. KAVALEC: Would you mind waiting a second, Sierra?

MR. MARTINEZ: Sounds good.

MR. KAVALEC: Yeah, go ahead, Monisha.

MS. GANGOPADHYAY: Hi. I imagine Sierra might be asking a similar question.

So, the revised demand or the adopted demand forecast is due for completion at the end of the year and sort of concurrently with that there will be a 2014 update that would be due for completion in February of 2014, to be used in the 2014 LTTP cycle, which would tentatively begin in March of 2014.

As I understand, there's some contemplation within the DOG community around calculating energy efficiency potential by the climate zone, within the utility service territories, and that would take some time to complete.

I'm wondering if that -- if those inputs would be incorporated in either the 2013 demand forecast or the 2014 update in time for the 2014 LTTP cycle. And if the 2014 update is -- I understand this is about the 2013 demand forecast, but I'm wondering if the 2014, if the schedule is on target, as well.

MR. KAVALEC: So, as far as I know, what we're planning to provide for the 2014 LTTP forecast, or LTTP analysis is the forecast we're doing this year, in 2013, which will be adopted towards the end of the year.

We're not planning to do an update of the forecast before March of 2014 for the LTTP.

MS. GANGOPADHYAY: So, do you anticipate that the climate zone impacts can be utilized for the demand forecasts that would be used for the 2014 LTTP?

MR. KAVALEC: Yes. And in fact we've talked to Navigant about this and they will have incremental uncommitted efficiency results projected at the climate zone level, and they will fold in nicely to our climate zone forecasts that we have in our -- in CED 2013.

So, yes is the answer.

MS. GANGOPADHYAY: Thank you.

MR. MARTINEZ: Hi, my name is Sierra Martinez and I'm the Legal Director for California Energy Projects at NRDC.

First of all I want to say thank you, Chris, for this presentation and to staff for all of the tremendous work that goes into these forecasts. I know it's a very complex effort.

And I wanted to say thank you to all of the heads and representatives from the joint energy agencies for appearing here today. It's a wonderful sign and a show of a committed effort to get on the same page with respect to energy efficiency forecasts, as committed in the previous Senate Energy hearings.

I would also add that in addition to getting on the same page for energy forecasts, part of the goal is to ensure that we get the most reasonable energy efficiency forecasts.

Two quick points on the presentation, first of all, NRDC is hugely supportive of updating the end-use surveys. Those are critical to making sure that we have a reasonable forecast.

Secondly, on the name selection, NRDC would recommend, simply, “projected energy efficiency savings.” “Projected” is simple and it’s commonly used in reference to other factors in the forecast.

When we forecast economic growth, which has tremendous amounts of uncertainty around it, we don’t qualify it as “uncertain economic growth” or “uncommitted economic growth.”

So, we would simply recommend “projected energy efficiency” like we have “projected economic growth.”

We look forward to working with you between now and August on the project energy efficiency assumptions. Thank you.

MR. KAVALEC: Okay, I think in the interest of time we will move to our next presentation. So, I’ll ask Hill Huntington to provide us his presentation, the economic and demographic projections and data.

MR. HUNTINGTON: Good. Thank you and I appreciate the opportunity to talk a little bit about some of the work we've been doing with the Expert Panel.

My name is Hill Huntington. I'm with the Stanford University, the Energy Modeling Forum. And I'm going to be reporting a little bit on some of the discussions we've had within the Expert Panel on energy demand.

Actually, the conversations that I'll be talking about are really discussions that I've had with not only the California Energy Commission staff, but also other members on the Panel. Jim McMahon is one and then Alan Sanstad's the other.

We actually have a fourth person who's really doing a lot more work on some of the hybrid modeling, combining statistical with end-use models, but I'm not going to be talking a lot about that. But that's Mark Jacquard, who is from British Columbia.

So, what I'd like to do is just go through a few of these things. Up and down? Oh, I hit the wrong one. Okay, I gotcha. I've got it now, okay. High technology here, you know.

So, we were asked to respond to a few issues, one of which is just to review the available model structures that are being used for the national economic forecast and then the California economic forecast, along with a demographic forecast.

And we were asked to look at the advantages and disadvantages particularly with regard to the IEPR forecast. So, that's the first issue.

The second one is to compare the accuracy of some of these projections with known historical trends, and so I'll give you a little flavor of some of the kinds of things we've been doing there.

And then, finally, I want to evaluate whether these projections are adequate for capturing some of the uncertainty when you're going about the effort of putting 10-year economic and demographic trends together.

So, the IEPR economic projections, as Chris has already talked about, actually combines a number of different groups here and the groups we looked at particularly, in our looking at the discussion, had to do with some of the models from Global Insight, Moody's, UCLA, and the demographic of the Department of Finance.

What we did was -- well, when we looked at the projections, it's important to know that they do both California and U.S. forecasts. These are coordinated with each other, but they are done independently, in separate models.

It’s not like you take the U.S. forecast and just simply share out what California’s share is. There’s a whole separate set of models to do California.

And in each of these models there are a lot of equations that people have there. And, in fact, that’s some of the challenges of doing some of the work that we want to do, particularly with regard to uncertainty, is that these are fairly large models.

One point I should emphasize, we’ve talked about getting more granular projections. We discussed with the different proprietors how they go about the question of modeling particularly at the metropolitan area, or any kind of disaggregated level of the states.

And I think it’s safe to say that the overarching conclusion here is that it’s not modeled very well there. And the reason why it’s not is you run into some very serious data constraints when you’re talking about some of these important drivers. And so, I thought that was important to bring up in this discussion.

And then, finally, on demographic projects the groups tie these in with economic conditions. So that if you have a more robust economy, that attracts more migration into the state and you actually see that kind of relationship going on.

So, what are the advantages? Well, there are lots of advantages that I'm sure people would have for any of these models.

But the one, let me just put out very quickly, a lot of these models are really geared, primarily, to look at more shorter-run kind of considerations which, you know, people worried about monetary policy or taxation issues.

But they run these projections tied with the long-run path of the economy and that's -- and so I think that's kind of -- it's an advantage that they're not just looking at short run, they're looking at the combination of short run and long run.

And lots of times these models are used to look at a particular policy. You want to look at, well, oil prices changes, or we're going to change monetary policy, they're very good at looking at those kinds of simulations, as you're doing one scenario at a time.

And as I said before, they integrate California with national economic conditions.

Disadvantages, now, I'll say these from our perspective of the Panel, one of our questions we really wanted to look at was are these projections giving us a good idea of the uncertainty involved when we're looking at these projections?

Because as Chris has pointed out, this is a very important driver in the projections.

And we felt, in general, that there were some really serious -- some really uncertain issues in terms of the long-run growth pattern of the economy. People are really asking the questions of if the economy will recover, how important will the demographic composition of the labor force be and do we have the right skills?

What's happening to the long-run productivity growth in the economy?

There's some real serious issues that have to be addressed and these models do have long-run issues in them, but that's not the primary thing that they were originally developed for. They still do pick up these issues and I don't want to say that they don't, but there's not as much concreteness around those issues.

And so that's -- that led us into thinking of the question, particularly if you think about more pessimistic scenarios, and I'll talk a little bit about that as we go forth.

And so, that's one issue is whether the long-run growth paths are being picked up.

A second issue had to do with whether or not they’re incorporating the uncertainty in the way that we’re used to thinking about it in the energy sphere. And, in particular, how do you assign a probability to a particular kind of scenario? You have a lower-growth scenario, how do you tell the decision maker what are the chances of that happening?

And we found that the Moody’s had done an interesting technique. For those who are really into it, it’s called Monte Carlo analysis. Just think of it as kind of doing lots of repeated simulations to try to get numerical results that will tell you -- will kind of address the question that instead of you having two and a half percent growth, you had a two percent growth, what’s the chances that that’s going to -- what’s the probability that that would happen?

And so, Moody’s has done this kind of analysis and we think it’s a good start. It’s interesting. There’s still some issues that need to be addressed, which input variables do you change? And how comprehensive are you in considering these different types of inputs?

There’s also a question of sometimes there’s some correlations going on between these -- you know, you’re changing factor A and it’s changing factor B. Well, like economic growth and energy prices, they may actually move together. So, is there an issue there that you have to worry about?

And then, finally, there's the important -- there's the issue of trying to identify which are the most important factors that you're going to change? Because these models are large, you could change, probably, easily a hundred different variables, but you really want to focus on the most important ones.

So, all these questions came up in our discussion and it wasn't as easy to just sit down and sort of write out an easy conclusion of this. And this will be reflected in some of my final comments, as we go forth.

Now, how are these variables doing on what is projected? And, again, we could spend an awful lot of time going through this.

But we just took a few variables, just for the presentation here today. And one is the change in total employment for California as you're going over this period of time.

And what you see in the really, the line that moves a lot, the blue line, the blue with diamonds there, that's actual history. That's actually what you see happening in the change going on, the change in employment over time.

And then you look at all the different projections and the big story here really is that they really missed the recession and they tend to be a little bit -- they tend to be a lot high on the great recession, and they tend to be a little bit high otherwise.

But, again, I think as you go out in time they seem to be picking up -- they seem to be getting closer and closer to what's actually happening. But that's certainly a big story there.

You probably can see there are two projections that are almost on top of each other. I tried to put them in separate coloring. They're at the very top there, with the dark maroon and then the lighter blue there. So, that's on total employment.

The other issues are going to be very similar kind of story. This is personal income. Again, the actual number moves all around, but it tends -- the projections tend to be high, particularly over that recession period of 2008 and in the 2009 period.

And then as 2010 and 2011 come in, the projections are closer to each other.

Manufacturing jobs, the same kind of story with these projections and then, finally, the -- this is the population growth, actually. Again, the projections tend to be a little high on the population estimates, particularly over this recession period.

So, that kind of gives you a flavor of what it is. And as I'm speaking about some of the scenarios, we then kind of thought about the issue, well, how do we use these projections to develop scenarios that people would want to look at?

And as I said before, the past projections tend to exceed the actual economic and demographic growth, particularly over the great recession.

And when we looked at the estimates, they often came up with an optimistic case. And when we looked at that, we said, yeah, maybe we could improve that, but they probably did a pretty good job of kind of taking a situation where you're more optimistic about what would happen with GEDP.

So, we didn't spend a lot of time worrying about, too much, of trying to develop another scenario that would reflect those conditions.

But when it came to pessimistic cases, we felt that there was still quite a bit of uncertainty there, and because of this recent experience with the great recession.

And we thought that -- and, in fact, when you look at a particular model, I think the Moody's model is a good example, but I think the Global Insight's the same thing, maybe they have six different scenarios, five of them all have to do with maybe more pessimistic cases.

So, that kind of lends you to kind of feeling that that's probably a good statement of where people think the real uncertainty is involved in these issues.

So, what did we do? I think we talked it over and, of course, in all of these discussions we had with the proprietors of the models, and we talked it over with the Commission staff, and I think we said, well, let's go with an optimistic case.

But when it came to a more pessimistic case, we thought more work needed to be done just to kind of make sure we were covering bases, because there really is a lot of uncertainty about these issues.

And we were suggesting something, which is I think pretty much what Chris and his group have done, a longer-term growth rate as one of the conditions, and combine that with a second recession somewhere in that projection.

Now, this is kind of like a way that I think builds in a little more caution as you're developing a pessimistic case, and that was pretty much what we thought about.

So, where are we now on this particular thing so far? We've had these discussions with the group of proprietors of these different projections, the different modeling systems. They've been very helpful, I have to say, they've been very forthright in saying this is what we know, this is what we don't know. It's been some great discussions.

Clearly, these approaches have their strengths. I can't imagine trying to develop a consistent set of projections just using any other kind of technique, and they do pick up some important economic linkages.

I've mentioned a couple of concerns we had. One was the uncertainty about the long-run trends, particularly with regard to the more pessimistic assumptions.

Another concern we had was just how do you represent this -- how do you take a really large model and communicate the idea that we are uncertain about these issues?

So, our plan at the moment is to, once we kind of get the projection moving along a little bit, in terms of future work we want to continue these discussions with the vendors to understand just really would be a good way to incorporate some of these -- some of the scenarios. So that when they come up with a pessimistic case are we talking about is that a 30 percent chance of this happening or is it a 10 percent change of this happening? I think this is useful information that we should be trying to communicate to decision makers.

So, that's what we're trying to do. And I think by having this interaction with the group we'll have a better understanding of some of these fundamental uncertainties.

And I believe at that point we'll probably be in a good position to maybe even develop some -- our own scenarios for the California Energy Commission that will really come to grips with these issues.

So, it's not a short answers, it's not like, oh, we sat down and we decided to do this. Because the animal, the models were much more bigger and complicated than we thought, but we do see some opportunities to improve the representation of uncertainty in these models.

So, with that I think I'll just kind of wrap up my conclusions and ask if I could address any comments that I might have gone over too quickly in my brief presentation.

COMMISSION CHAIRPERSON WEISENMILLER: Well, first, I wanted to thank you. And just for some background for the other agencies, when I was arriving here I had a letter on my desk from President Peevey, commenting on our demand forecast or the methodology.

And so, one of the things I wanted to do was provide some of this outside -- bring in an expert panel. We have a very good staff, but to provide some outside perspective.

Obviously, one of the things Chris and his people are doing are always sprinting to the next deadline.

And so to step back we hired an Expert Panel to help us on this and take the longer-term perspective. And, you know, you're hearing part of the results today of that.

And so, again, I think it's sending the basic message that we take this very seriously and, certainly, we're reaching out in all the ways we can to improve what we're doing.

I think the other question for Hill is that on the econ demo, one of the reasons that was driving my thought on disaggregation, aside from the fact that, like I said, a lot of our need or assessments really are based on a local level, is that it seemed like in terms of recovery from the California great recession that when we look along the coastal regions, you know, the economy's coming back pretty strongly.

But in the inner regions, you know, the Central Valley, the Inland Empire, it's really lagging.

And so one of my concerns, particularly as we're doing this more local planning, is not having that sort of smoothing together of sort of relatively robust growth and relatively dismal growth giving us sort of wrong message for some of these areas.

MR. HUNTINGTON: Yeah, that's a great question. And I think in our discussions with the different groups it was very much -- we talked quite a bit about this, how California is, at a minimum, two separate states and probably bigger than that.

But you really had to separate out the inner regions from the coastal regions.

And, indeed, when you talk to these people and they're doing their aggregate -- they're doing the California estimates, they're very much aware of that.

And I think that even if you asked them could you do a more disaggregate along the lines that you just suggested, I think they could do that.

I think what they were trying to tell us, though, is that if you really tried to get down to the metropolitan area or the county level, some of the levels that people are really talking about trying to do for -- I mean, for electricity, energy efficiency's a great example, or solar panels. When you start getting down to those levels, getting the economic drivers right for those is going to be a challenge. That's what I was trying to get across on that.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, I know. Yeah, I mean one of the things which -- you know, having gone through prior rate case filings, you know, the thing is when a utility builds up its budget for the distribution system somewhere embedded in that is something for all the local areas.

Now, it may well be a straight line and it may not be particularly sophisticated in terms of econometric demographics, but there is a forecast differentiating between, say, San Francisco, Walnut Creek and the Sacramento area on what the distribution system needs are.

And again, it may not be particular good but, certainly, at this point it's not very transparent on what the uncertainties are, or even how they got there, other than perhaps someone in the district office drawing a straight line.

MR. HUNTINGTON: Yeah, and I guess that's right. And I guess what these guys were telling us, at least I'm interpreting this now, is that they were saying they have more confidence on their projections, on their aggregate projections than they do when you get down to the smaller -- and as you go further and further down into the local area, their confidence level falls off a bit, I guess.

Any other questions on that? I know I covered that material pretty quickly, but I did want to at least -- yeah?

MR. FLORIO: I'm struck by the concern that it's the more pessimistic cases that you're concerned aren't being adequately represented. Because as people dealing with the energy system and wanting to make sure we have enough to meet our future needs, we tend to worry most about the -- you know, things will be better than we expect and we won't have enough energy as a result.

Were there similar concerns on the upside or is it really -- you've emphasized that the more pessimistic cases are the ones that you don't think are adequately represented. Is it weighted pretty heavily in the downward direction?

MR. HUNTINGTON: Well, no, I think we thought both were really important. And one of the discussions we had was we tried to get people to talk about, within the utility planning and policy arena, is it more important to be -- is it more important to -- are you going to be in worse trouble if you over-estimate or under-estimate? That's basically the question.

And we got, actually, a range of results. Some people said, well, if you don't get enough, maybe you can always -- at least, and it's a short enough time period, you can at least trade on the market and maybe you'll work around that.

But there was a quite a bit of discussion about that and we actually think that that is still an important issue that we began that discussion, and we got part of the way there, but I don't think we ever really got the group -- we also met -- I should add we met with people from the utility industry, and we'd love to get their reactions to this because -- because that's an important question. That's probably the question number one.

The question number two is when you look at the economic and the demographic, why we spent more time on the pessimistic case was we felt that there were still some concerns about whether the economy was going to recovery as rapidly or not.

And so I think when I say we spent more time on the pessimistic, I think we were reflecting within the set of models where was their uncertainty larger, but that may not be the key uncertainty for what you have to consider. So, that's a great point, I think that's great.

MR. FLORIO: The other part I wonder about is we redo this every two years, at least, and often every year. So, to the extent we're off in our longer-term projections, you know, that could start to get picked up year by year.

I mean any thoughts about that?

MR. HUNTINGTON: Yeah, so if I think I interpreted you right, you're sort of saying you're looking at it and now, one or two years out, you look at it and say, well, we're missing this so, therefore, we need to make an adjustment. I think that's exactly right. And, in fact, that's really the way to use this.

These are plans, these are -- this is to help the planning process, it's not something that's going to be in concrete for the next ten years.

And so, when you're going through that analysis you -- I think it was Eisenhower said that "Plans are worthless but planning is everything," or something, but that kind of notion.

Using this as a planning device is great, but just as a plan that you kind of file away is really not a good use for this kind of report.

MR. FLORIO: Thank you.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, just to follow up, I think just so people are clear. One of your conclusions last year, if I remember right, was that while we have a range from low to high that range is probably too small that the uncertainty's greater. Is that a fair characterization?

MR. HUNTINGTON: That was our thought about it. And I think, partly, it had to do with the fact that we'd just gone through this experience of going through the great recession and that's kind of woken people up a bit that maybe the bounds are a little bit wider than what they're used to be looking at.

And that's one of the reasons why we kept asking the question of how could we kind of make this -- I think implicit we had this in mind, we wanted this uncertainty, in our own minds at least, to be within a certain range and we were looking for ways to make it a little broader in our context.

And I think they are, but not -- on the other hand, you don't want to make it so wide that it's not useful at all, so that's the balance that you've got.

MR. FERRON: Well, I think this was an excellent presentation. I think the way I'm thinking about this is not so much about the scenarios, the levels of optimism and pessimism, but the likelihood of them. And that’s something which we don’t really address here.

But I think what I take away here is when we do projections we look at long-term structural parameters, like long-term economic growth potential, and those things tend to evolve relatively smoothly.

Where we miss it is in the macro economic variables, which are -- which tend to surprise and they almost always tend to surprise to the downside, first. You know, you have a recession followed by recovery, as opposed to a rapid acceleration followed by -- you know, it’s the things which stimulate growth to the upside don’t tend to surprise in the way -- but I think Commissioner Florio’s right, we worry about being surprised to the upside.

And that may yet happen. There may be some kind of technological evolution where suddenly there are all sorts of devices that require a lot of electricity. But those, I think, because we do reforecasts every couple of years, and we can observe the market uptake of that, we’re less likely to be surprised by the drop off in demand which, in a sense, is all good news in that we have very asymmetric risk.

Having electricity shortfall is, in a way, much more painful than having over-capacity.

MR. HUNTINGTON: Good. Okay, thanks.

MR. KAVALEC: So, for our next presentation we will hear from Alan Sanstad from Lawrence Berkeley, on the disaggregation question.

MR. SANSTAD: Thank you, Chris. And thank you, Commissioners for the opportunity to present a few remarks today.

I want to say I am here as a member of the Expert Panel that Hill is leading. Purely through a fault of my own, my colleagues did not have a chance to go to review and comment on the presentation today, so I'm not going to implicate them, at least not yet. So, that's why only my name is on it.

(Laughter)

MR. SANSTAD: My talk is picking up and enlarging upon one of Hill's themes about uncertainty.

So there are, of course, very sound reasons for moving ahead with increasing the granularity of the forecasting model and building out down to higher levels if disaggregation. Coordination among the Energy Commission, the PUC and CAISO, better representations enable the capability to represent efficiency programs and renewables at the disaggregated level.

But the theme I want to pick up on is that it's important to recognize that here, as in other areas of computational modeling, this kind of effort involves costs, as well as benefits.

And regardless of how it’s down there is likely to be certain limitations on what can be achieved in terms of the performance improvements, the resolution improvements that we’re seeking.

The first is very sort of practical and hardly surprising, and Hill talked about this, and it’s data. As granularity increases for any model, the data demands to populate the model increase.

Obtaining, generating or otherwise coming up with high-quality data needed to parameterize the forecasting model, in particular, at a high degree of spatial disaggregation is likely to be quite costly and in some cases may be impossible. By impossible I just mean that the data are not there and it would be prohibitively expensive or time consuming to come up with in any practical way on the time skills that we need the model to evolve that.

So, you know, as one would expect, using sparse, incomplete or lower-quality data than is otherwise available will tend to offset the gains from increased resolution. You’re building out a model, but your confidence in what it’s doing at the disaggregated level may decline.

There’s a related issue, which is also practical and it’s been around for a long time, which is accuracy at different levels of resolution.

So, in part, but not entirely because of the data issue it’s easier to predict aggregate quantities, often, than very disaggregated quantities.

So, this is not something that’s peculiar to energy modeling. Economic growth, projecting U.S. economic growth five years out, as opposed to Sacramento economic growth five years out, they’re different animals.

An example that’s fresh in my mind, I recently did a paper that looked at the energy model the USEPA uses for -- has traditionally used for air quality regulation and is now using to develop the greenhouse gas regulations, the greenhouse gas electric power regulations.

So, I looked at a study they did in 2002 for one proposal and their national aggregate projection of electricity demand was, really, right, remarkable good over a ten-year, it was a forecast error of less than five percent.

But the model’s disaggregated regionally in what would now be the NERC planning regions for the transmission system. There are regional errors up to 20 percent, okay. I mean the aggregate looked much better than the disaggregate.

Why this happens is complicated. Partly it’s data and statistical, partly, as in many other cases that have been revealed, there may be off-cancelling errors, depending on how the model is put together, but it’s a cautionary tale.

Now, to move forward there I want to introduce something that is quite more abstract, but it is a general issue that has been around for a long time in statistics, and allied fields, including econometrics, but it’s being more and more addressed in sort of a focus of interest and research in other forums of computational modeling, as modeling expands in science and engineering.

So, there are principles of complexity, accuracy, uncertainty that apply to the goal of developing any high resolution model, including the one that we’re looking at here. So, it’s a tradeoff. There’s a tradeoff between increasing the model accuracy and on the one hand you’d like to increase accuracy, you’d like to decrease uncertainty as the model gets more complex.

But there’s a fundamental limitation to what you can do, it’s called the bias variance tradeoff. And here’s a mathematical expression of it. This looks --

if you’re not used to this, it will maybe look a little hairy, but it says something quite intuitive.

So, you think about a model, you’re forecasting or trying to predict some quantity of Y with a model, you have inputs, you have a model, and you say, okay, I want to predict Y.

So, a basic measure of forecast error is what’s called the mean squared error. In some applications this would be like a least squares type metric.

E here is expected value, mathematical expectation or what you would expect to happen on average.

So, there are two terms, the mean squared error decomposes into two terms and one is called the bias. And what this is, is it’s the difference between what you’re trying to predict and sort of your model average, what your model would do sort of in its mean tendency.

The variance is the uncertainty that’s built into your model, okay. If it was a statistical model and you ran it many times, that’s going to have some spread and so the variance is built in.

So, the fundamental relationship here is the mean squared error is equal to the bias squared plus the variance. This is a mathematical relationship.

And the connection, the complexity can be illustrated here, which is -- there's the number of parameters or, more generally, the model complexity increases, the bias may very well go down, particularly if you're using statistical techniques in that sort of application. But the variance of the uncertainty will go up.

And there are techniques to sort of try to optimally trade this off. One can put them together and minimize. But the fundamental tradeoff exists.

And as I want to emphasize again, this is traditionally something that's been looked at in statistics, but it's more there's research that's going on in the frontiers of applying this to general computational models.

So, in the situation we're dealing with here, which is the common situation of energy modeling, the model is not sort of overtly statistical. I'm not talking about the econometric models, but the demand forecasting, the basic demand forecasting system that's been around since the 1970s, essentially a deterministic model.

So, there's an additional layer of something to think about here, which is that in a model like this, as is common, you're not going to generate a lot of projects, right. So far we're not moving into doing the

Monte Carlo and so forth.

So, when you’re only -- when you have a deterministic complex, a deterministic model you’re only running it a few times. You may be actually getting it coming and going as it were. As the model gets more complex, you may be increasing the uncertainty, but without gaining the -- reducing the bias or getting an increase in accuracy because you’re not doing it a large number of times, you’re sampling from an increasingly -- one model simulation, you can think of it as a sample for an increasingly uncertain distribution, implicitly.

So, it’s a danger that the uncertainty effect would actually end up dominating. And now this is subject -- this is very abstract, of course, subject to many, many details of a particular model implementation.

COMMISSIONER MC ALLISTER: So how is --

MR. SANSTAD: Yes?

COMMISSIONER MC ALLISTER: Is there any way to know? Is there any way to, you know, validate with real-world data to know how, you know, whether bias is decreasing or not?

MR. SANSTAD: In principle, yeah, there are definitely techniques to do this. It’s a complicated problem. It’s not an easy problem to solve.

As one gets into more and more complicated models and particularly models that are extremely high dimensional, but sort of fundamentally non-statistical, the problem increases, right.

And part of what we're talking about in the Expect Panel is in the evolution of improving the demand forecasting system how can we introduce sort of new ways of generating scenarios, assigning probability.

So, that work would tend to head in the direction that we might be able to get some traction on this. But in general, it's possible. It's a hard problem.

So, you wonder why, this may be novel considerations. It's coming. As I mentioned, this sort of thing is being increasingly attended to in scientific engineering computation. It hasn't been talked about so much in energy modeling.

I think there are a number of reasons. One is that the consequences of getting it wrong in the energy policy modeling have traditionally not been that great, okay. The models used to generate long-run insights scenarios guide decision makings rather than actually forecast specific numbers which will be used in a very concrete way and acted on.

But in the terrain we're moving into now, in California, we may want to exercise a little more caution.

And I have in particular in mind that the use of the CEC forecasts by the CAISO and part of the big justification of the granularity is for them to do operational and system planning, okay.

My understanding of all their processes is still, shall we say, nascent, but it’s very complicated.

But I think it’s worth -- it’s a concern that as you move -- as the forecast moves, the application of it moves more and more into actual system planning that these accuracy issues are going to become more critical.

That Commissioner Florio brought up something very important, which is that this stuff is never written in stone, right. The dynamic -- the process is dynamic, the planning process is always updated.

But I think that we need to think more carefully then, possibly, than has been in the past about, literally, the accuracy of the forecasts and the consequences of forecast error. Forecast error is a fact of life. Every model’s wrong and so forth, right, and you’ve heard this many times. All models are wrong, some are useful.

The manner in which they might be wrong I think we want to have -- bring closer to the center of our attention.

So, just concretely, what we're talking about here, for example, is moving down from utility service territory level resolution to census tract level resolution, in principle.

So, this can be done, this kind of disaggregation, several different ways. For example, one is to keep the aggregate forecast calibrated to what it was, but filled down, right. So, you don't really build back up the model, but you make it more complex and fill down.

So, if you had good accuracy in the aggregate, that would be maintained. But in this case you have to wonder about what you're introducing in terms of error at the more disaggregated level.

On the other hand, one could increase the resolution of the model and then built it back up from the bottom.

In that case one has to wonder especially about what new kinds of error might be introduced in the aggregate because of the issue of -- both the issues I've talked about, the data, sort of the relationship between aggregated and disaggregated. And always in the background, this fundamental issue.

Again, Commissioner McAllister's point is well taken, there's no hard and fast way of testing some of these always in practice, but all the considerations are there.

So, the recommendations I would suggest essentially are pretty straight forward.

One is to really take a look at the data availability and quality before moving ahead full steam with the increasing granularity. It’s not -- you know, the data are always, you know, too scarce, too low quality, not what you want. That’s just the way things work. So, it’s not saying if it’s not perfect, don’t do it.

However, I think in this case it’s important to be very clear and thorough about this as the process moves forward to understand where the data issues might be more and less severe as the model gets more granular.

And second is, as this process goes forward, is to analyze the implications. I’m sort of repeating myself of a few minutes ago. Analyze implications of possible increases in model error at different levels of granularity for the planning process.

So, for example, how would the CAISO hedge against forecast errors that might -- at the very, very disaggregate level that might be introduced or might be increased here?

They have a very sophisticated risk management and planning system, of course, so I think that going forward this kind of problem is certainly within their realm of technical expertise, and the realm of the expertise of all the agencies.

But I would suggest that it might be highlighted as a priority area going forward.

So, I look forward to further discussion and engagement on these issues.

COMMISSION CHAIRPERSON WEISENMILLER: So, a couple of questions.

MR. SANSTAD: Yes.

COMMISSION CHAIRPERSON WEISENMILLER: I mean, obviously, disaggregation, as you say, you know, has lots of uncertainty.

We've gone to the climate zone. I think probably our next leap might well be to the local area capacity markets for the resource adequacy part.

But in fact, whenever we adopt a forecast, basically one of the next steps is the ISO magically disaggregates it down to substation.

And in the PUC context, again, it is that sort of substation level.

So, in fact, there is planning already. Now, the question is, you know, how do we have the conversation about the implications and how do we provide somewhat better guidance but realizing that, you know, Chris doesn't even want to think about substation level forecasting. And, indeed, you know, that would require us to say what HP is going to do next year, or Apple, you know, once you got to the substation. So, it's just a total nightmare.

But somehow in the planning process or operational process they do go all the way down to that level.

MR. SANSTAD: Right. Something I've been starting to -- you know, as I said, my sort of developing understanding of what they do is that, yeah, they've been doing this already.

I think part of what that implies is there's an institutional issue here, not just a technical issue, about the interaction, you know, engagement and cooperation between the Energy Commission and CAISO, if the Energy Commission is always doing this.

I mean and that's sort of the first thing that came to my mind. Okay, if Chris were to do this and they're doing it already, okay, now, how does that work?

Because they have different procedures, they have different models and they have different sources of information, too.

So, I think it is, in part, a significant -- you know, it’s an important coordination problem, as well as a technical problem.

COMMISSION CHAIRPERSON WEISENMILLER: Go ahead.

MR. CASEY: Yeah, if I could just add on to Chair Weisenmiller’s comments on this. That was certainly going to be my opening comment is we do do this, we do disaggregate down to the bus level. And it is a process of taking the CEC forecast at each planning area and then working with the utility. The utility, ultimately, does the disaggregation down to the load bus and that becomes the base case that we use for our planning assumptions.

I do take a little umbrage with the notion that, well, we shouldn’t worry about it too much because it’s just planning.

We do, actually, approve infrastructure improvements based on that disaggregated load data.

Now, we do mitigate some of the risk, given the uncertainty, in that if we see a need, particularly in the lower voltage systems, that is driven more in the five- to ten-year time frame, we may defer taking any action on that until we get closer to that operating time, if the upgrade has sufficient window to allow that.

But the fact of the matter is that, you know, the electrical system does have to be modeled at that level of detail.

And I know it’s hard and there’s a lot of uncertainty around it, and we need to get better at it but, you know, that’s just a reality that it happens today and will continue to happen in the future.

And the thing I wanted to stress is as we move forward with looking at alternatives to what I would call traditional infrastructure, whether it’s transmission lines or conventional power plants, you know, the ability to project at a granular level of what we think things like demand response or energy efficiency will do is going to be critically important.

And, you know, it’s not only what do you think the demand is in those locations, but what’s the composition of that demand. Because if you’re looking at targeted energy-efficiency programs, you know, how much of the demand there is residential, industrial, commercial and what types of energy-efficiency programs would be most effective at reducing it.

So, I realize this is a huge elephant that we have to take on one bite at a time, but the -- you know, the approach that Chair Weisenmiller suggested, maybe focusing on the local capacity areas certainly, I think, has merit.

We might even want to go more granular to looking at, perhaps as part of the pre-planning IEPR process, what are the critical load areas from an infrastructure planning stand point we know are going to be important, and maybe focus the more detailed granular forecasting for those areas. So, maybe you just have a dozen areas instead of, you know, 3,000 load busses.

And then I do agree there’s a handoff from how far the CEC takes it in terms of level of granularity to where the ISO, and the utilities, and the other planning areas in the State can then take it and drill down further. And that’s a scenario that I think we need further discussion around.

But as I said in my opening comments, this is a really critical area for us and we do have to get better at this, despite the challenges.

MR. SANSTAD: Yeah, definitely. Yeah, and I hasten to emphasize that what I’m trying to say here is certainly don’t not do this, but about how it should go forward to maximally incorporate some of these considerations.

I would think, you know, and again because it’s been going on, as you say, for a long time you already do this.

I think part of what’s at issue here is that in the energy demand modeling world it hasn’t been going on, right. And so, and there are new -- I assume that as you add that sort of demand patterns that are relevant to efficiency planning at this very disaggregated level that adds a new element of uncertainty into your traditional practices.

And so, I think it’s the nexus here between those two that is sort of the critical thing, how the methods you already use, which evolved implicitly or otherwise, explicitly a certain amount of risk hedging can be brought on board as this proceeds on the demand forecasting level.

MR. FLORIO: Yeah, to put this in a very real-world context, you know, we have a large nuclear plant that’s inoperable in Southern California and for all we know may be dead.

And from a statewide perspective, the implications of that are not that significant. But for people in Orange County and Northern San Diego County it’s an enormous issue.

And, you know, the only way we figured out to deal with that is we need to be a little more conservative in what assumptions we make and bias our decision in that direction given that, you know, we can’t be sure. You know, the range of uncertainty is larger for the smaller area, so we discount some things that we might not discount at the larger system level.

And I'm not sure there's much better than that we could do at this point.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah. I mean just following up on Mike's comment. I mean, the first thing we really have to deal with is, you know, people talk about demand response, say on the Edison system, but we need to know how much in Orange County, not anywhere in the Edison system.

And the other is just operationally this summer I mean we're looking at five subs in Orange County. And if they go out of balance, we curtail.

So, when Mike's looking at options on how do we deal with those, it really is at a substation level.

Or again, it's not -- you know, we might -- statewide we're happy, northern -- you know, everything looks good, but that sub -- we may darken that sub if things go out of balance.

MR. SANSTAD: Oh, absolutely. And again, I can't emphasize enough that the importance of doing this increasing granularity is very clear. I mean you're giving examples of that.

It's just some of these considerations need to be kept firmly in mind because the uncertainty, the exigency of having to do it does not eliminate the fact that there may be an introduction of considerable new uncertainty in practice.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah.

COMMISSIONER MC ALLISTER: So, just taking a little bit longer term, because I absolutely agree with what Mike and Bob have said here, I guess, and without -- at the risk of going a little too wonky, I'll try not to do that.

But I guess to the extent that demand response, you know, we are looking at different supply options. And, you know, I agree with Keith on let's focus on what, pragmatically speaking, are the important areas and the important issues sort of from a technical perspective.

But it might actually -- you know, if we can find a practical, sort of relatively straight forward way to understand the -- you know, basically, the broader uncertainty in any given case then maybe that can help us. If we can quantify that in some way then maybe that can help target what strategies might fit different cases.

So, you know, long-term it's sort of like, okay, with demand response how real is that going to be in allowing us to avoid more traditional supply options and not increase our risk and our uncertainty of brown-outs, right.

So, if there’s kind of a relatively low probability and we’re not sure, you know, kind of -- there are a certain range of probabilities for a given scenario, then maybe that, in and of itself, could be a reason why we would go focus on demand response there, or focus on a given resource type.

So, I see some promise here, but it’s certainly a long-term promise, not a this-summer promise. But kind of understanding this going forward, if we could pick some metrics and sort of work through this in a very pragmatic way that would be great.

MR. SANSTAD: You know, the practical perspective is the one to adopt.

And to answer your previous question about methods for dealing with this kind of stuff, so and this is something that CAISO might already be doing, there’s a modeling analysis area that’s called inverse modeling, right, which would -- which might help here. It’s sort of a decision analysis, okay.

If you look at where you’re analyzing demand response at the very granular level and there are some decisions that have to be made about system planning to take account of it, okay, so now you’re here, so work back up. And say, okay, what are the implications -- you know, what are the implications of your error of possible uncertainties in your model for this decision, okay, and how is it going to affect it. What sort of granularity do you exactly need in order to sort of overcome the uncertainty in a way that you can count on the demand response.

So, there are different -- you know, this is all very quick, but there are different ways that one can do this that I think would be promising.

MR. FLORIO: Yeah.

COMMISSION CHAIRPERSON WEISENMILLER: Well, certainly, again, I think we're looking forward to the Expert Panel helping us think through disaggregation. I mean, certainly, as we go forward we know that we're going to have to think more about data, we're going to have to think more about the models. I'm sure Chris is going to need more help.

But again, we're trying to figure out the right balance and do this more step by step going forward.

But I think your notion of trying to do some targeted stuff, too, would really help.

COMMISSIONER MC ALLISTER: So, should we ask if there are questions from the floor, and the web? And we're running a little bit after time. Oh, public comments as well, yeah.

Yeah, great, so further questions.

MR. SANSTAD: Thank you.

MS. KOROSEC: Are there any questions for our speaker here, before we move to public comments?

Right now just I know you're getting close to -- we're getting close to lunch here, but I do want to give about five minutes for anybody here in the room, who may not be here this afternoon, if there's anything that you'd like to say now is your opportunity.

All right, seeing no one we're going to open. We've got three folks on the phone-only, and I want to give them an opportunity, as well. So, we're just going to open the phone lines for just a moment, all right.

Okay, your lines are open, if anyone needs to say anything before we break for lunch.

All right, hearing none I think we are ready then to take our well-deserved lunch break.

We are running a little bit behind but I think we should get -- Commissioners, with your indulgence, we'll go for a full hour for lunch.

COMMISSIONER MC ALLISTER: Yes.

MS. KOROSEC: Okay. All right, so we'll return back here at quarter 'till 2:00.

Thank you very much.

(Off the record at 12:45 p.m. for the lunch break.)

(Resume at 2:00 p.m.)

COMMISSIONER MC ALLISTER: I apologize for the delay. We had some logistical issues with our colleagues here. And it’s so much fun to have them in town we just couldn’t help to go out to lunch with them.

But I apologize for setting things back a little bit.

So, let’s get started in the afternoon. Suzanne, do you want to say a few words to kick us off or should I just -- okay, great. So, let’s start with the afternoon session with Asish.

MR. GAUTAM: Good afternoon everyone. My name is Asish Gautam and I’ll be presenting the customer side distributed generation impacts prepared for the preliminary forecast.

First, I want to go over the different sources of data that we use to build and track DG activity in the State.

First, we receive power plant reports from any generator that has a one megawatt or larger capacity. This source covers a lot of the industrial and mining CHP.

The next source is the Emerging Renewables

Program. This is one of the first programs to fund PV installations in the State.

The next couple programs are managed by the PUC. This includes the Self-Generation Incentive Program, the California Solar Initiative, the New Solar Homes Partnership, and POU PV installation that's submitted to us on an annual basis each year.

And one new source that we started tracking in the last forecast is the Solar Hot Water Incentives Program.

Other sources of data include a DG EM&V reports. Usually, the data that we track gives us capacity and location, and so we use the capacity and peak factors to translate capacity of energy in peak impacts.

Another source is the PV cost projections developed by EIA.

Something new for this forecast is the combined heat and power for the commercial sector and for that we are relying on a CEC-sponsored report that was conducted by ICF last year.

This is the second time where we are using a predictive model for the residential sector, PV and solar hot water to forecast residential adoption of PV and solar hot water.

The basic structure here is to look at -- to conduct a cash flow, a payback type analysis and try to use that to model adoption.

This is a method that's used by other agencies, EIA, NREL. I think a similar thing is used by other agencies that work on energy efficiency.

The payback calculation is based on looking at the system costs, maintenance costs, photovoltaics, we have inverter replacement costs, also factoring in any incentives and fuel prices.

The payback is applied to a Bass Diffusion adoption model and this is sort of the prototype, S curve shape that's used to model adoption of technologies.

The results differ by a demand scenario because of differences in fuel prices and housing stock.

This is sort of a prototypical example of the diffusion model. As you can see, there are different types of customers that would correspond to depending on where you are on the shape. So, that's that.

Next, for the residential sector model, the PV system cost and performance data comes from existing data collected from the CSI program and a couple of other programs, and we also look at the EIA's forecast. Solar hot water system cost and performance data comes from a PUC-sponsored study on the cost benefits of solar hot water.

We also rely on some internal products to do the forecasting for PV. We look at the residential sector model output and use that for system sizing. So, here the residential model will supply us with the estimate of average consumption and we would use that to size the PV system.

This is looking at the average consumption, factoring in the module efficiency and solar installation for each of the climate zones.

For retrofit application we were trying -- we constrained the system as to no more than 4 kilowatt. And for new construction the constraint is not more than 2 kilowatt. These are sizes that we kind of see in the CSI and the New Solar Homes Partnership Program data.

For the nonresidential sector, for PV modeling, we weren't able to complete a predictive model in time for this preliminary forecast, so we will rely on a trend analysis, similar to what we did in the last forecast.

Here, we're going to look at the rate of growth in past installations and apply that to forecast stock and then apply peak and capacity factors from the CSI and SGIP evaluation reports.

Something new for this forecast is the combined heat and power projections for the commercial sector. The basic idea here is to look at how to meet on-site demand for power and through thermal end-uses hot water and space heating.

To facilitate the analysis we looked into our CEUS survey data, this is our commercial end-use survey, to build electric and gas demand profiles for the different building types that are looked at in the commercial sector.

Just a quick summary of the survey, we had responses from 2,900 sites. It covers the 12 building types that's looked in the commercial model and there are four size categories.

We take these profiles and benchmark it to the commercial model output and the floor space projections, and then we have a tool that was developed as part of the CEUS, called DrCEUS. And this is a building simulation tool and it allowed us to create custom load shapes that helped us with the system sizing, and the CHP thermal assessment and economic modeling.

In the residential model we're using the average customer rates that's developed for the preliminary forecast, but for the CHP and the commercial we tried to incorporate retail electric and gas tariffs.

And this is basically we take the monthly peak consumption and try to match it to the applicable tariff.

Then we take the details of each tariff and escalate it based on the rate of growth projected for the commercial sector. The rate of growth in commercial electricity that was developed for this preliminary forecast, this is probably not the way to kind of go about it, because the way retail rates can be escalated is kind of involved sometimes.

You can see, you know, a big jump in certain tiers, or switch to different like charges, such as fixed cost or demand charges.

But to kind of simplify the analysis, we decided to just kind of escalate all of the components of a tariff by the rate of growth that's determined from the commercial rate.

The technology assumptions come from the ICF report that was completed about a year ago, and we're basically relying on all of the details that they came up with. This includes the heat rates, install cost, heat recovery, efficiency and maintenance costs.

And, actually, we basically will be using the DrCEUS load shapes to do the impact assessment. This will be total generation, on-site use, export and grid purchase. And all of this will be used in the economic assessment.

We also account for any SGIP incentives and tax credits for CHP. And from this point on the adoption modeling occurs the same as in the residential sector model.

As far as results, I'll be going over the statewide result. The individual planning area results will follow in the other presentations later this afternoon.

First, it's the non-PV energy impact. We start at about 12,300 gigawatt hours in 2012 and then grow up to just a little under 14,000 gigawatt hours, and slightly above 14,000 gigawatt hours.

It may be a little hard to see, but there are actually three scenarios in the top curve. What's going on is there's some offsetting affects that kind of -- where the net effect is the scenario results are kind of bunched together.

For example, in the low demand case we have high electric rates and also high natural gas costs for the CHP unit, but low floor space projection.

And then in the load demand we have low electric prices but -- and also a lower gas price for the CHP prime mover, but higher floor space estimate.

And so, the results are bunched together, but the net effect is the bill saving still is a dominant effect in the -- by 2024, the load demand is still about four megawatts above the high demand scenario.

As far as growth rates, the non-PV energy is growing statewide about 1 to 1.1 percent. This is the Non-PV peak impact.

When we were putting our data together we realized that there was an error in our processing of historical data. This caused peak impacts to be overstated starting in 2010, so we’ll be revising this downwards in the revised forecast.

The net effect is that the 2012 estimate for the preliminary forecast is slightly below the 2011 forecast and then starting in 2014 all three scenarios from the current forecast are above the 2011 forecast.

The growth is about just under one percent a year from 2012 to 2024.

As far as the growth from the commercial sector, new additions is about 249 to 253 megawatts, and that gives us -- and the growth in commercial adoption is about 4.3 to 4.4 percent a year.

Next is the statewide PV energy impact. All three scenarios are above the 2011 forecast. The main reason for this has to do with the higher historic growth and also the high retail electric rate projections.

Here we start at about just under 2,200 gigawatt hours in 2012 and end up just between 7,300 gigawatt hours and 8,700 gigawatt hours.

As far as growth rates, statewide it’s about 10 to 12 and a half percent a year.

MR. CASEY: I had a question on that graph. Can you explain what causes that inflection point in the projections?

MR. GAUTAM: Oh, yes. That corresponds to the reduction in the tax credit.

COMMISSIONER MC ALLISTER: Yeah, I was going to ask that question, too. So, I guess the PV, there’s a lot of uncertainty around the PV market just about, you know, rates, and we talked about that earlier this morning.

MR. GAUTAM: Yeah.

COMMISSIONER MC ALLISTER: And sort of, you know, what’s going to happen with the rate design activity. And then also, certainly, the tax credit, other incentives I think are less of a deal now. But maybe you could explain a little bit about those impacts.

Oh, maybe that’s in your next slide, sorry.

MR. GAUTAM: Let me -- this is the statewide PV peak impact. Let me just quickly go over this. The starting point here for 2012 is just under 2,200 -- 700 megawatts and growing to between just under 2,000 megawatts to 2,300 megawatts.

And the growth here corresponds to the energy just about between 9 percent to 10 and a half percent a year.

One thing I wanted to point out was that in starting in 2017 all three scenarios are approaching the CSI goal for the 3,000 megawatt of PV. And again, one of the reasons we reached that goal has to do with the higher electric and also the high growth in recent years.

And then just following up with what Commissioner McAllister had mentioned about uncertainties in the forecast. Right now the PUC's involved in the Cost Benefit Study, the NEM Program. And it's a little too early for us to look into how that will change, so that's something that we're not really getting into right now. So, we'll wait for the study results to look into how we're going to incorporate them in the revised forecast.

Another uncertainty is any changes in the retail electric tariff. There's been some discussions about moving to more fixed charges and reducing the higher price -- reducing the rates in the higher tiers and moving into the lower tiers. So, how that will impact PV adoption remains to be seen.

Another uncertainty, a big uncertainty is the Federal tax credit. And for CHP, some of the issues that we have discussed in past IEPRs has to do with interconnection and standby departing load charges. These things are still around. How they get resolved or how they change going forward will have a big impact on CHP adoption.

One of the things we'd like to hear from the utilities is how they're approaching some of these uncertainties in their forecasts for DG, so we'd be very interested in hearing from them.

As far as some of the goals that are out there for DG, there is the 12,000 megawatt renewable DG goal. At least based on our analysis, we don't get to that goal.

But this shouldn't be taken as something conclusive about if that goal can be reached, because we're only looking at a small -- or not small, but one slice of the goal, and that's just the customer side adoption. But then there's a lot of interest in developing non-customer-owned DG.

Not long ago, LADWP released a solar station for their PV feed-in tariff program, which was almost immediately over-subscribed. So, there is interest in developing non-customer-owned DG. But that's something we don't get into in the demand forecast.

I'm just going to go over some of the next steps for us that we will try to accomplish in time for the revised forecast.

We have our ongoing data updates. You know the program data get updated quite often, so we'd like to incorporate that and put it into the revised forecast.

One of the things we want to do is take another look at our residential sector model. When we designed this model for the last IEPR we -- it's really an annual model, so things like retail electric tariffs, and NEM benefits is something we don't quite touch. But we want to take another look at that and redo the model to be able to better answer some of these questions on net energy metering cost benefits.

We'd also like to finish our work on the non-residential PV model.

That is it for me, so I'll take any questions.

COMMISSIONER MC ALLISTER: Just one quick question. So, could you talk a little bit about the characteristics of your peak impact analysis for PV?

MR. GAUTAM: Sure.

COMMISSIONER MC ALLISTER: Well, I’m really thinking -- so, just looking at the left axis, the SB1 goal is 3,000 total distributed solar, but that’s sort of -- you know, that’s --

MR. GAUTAM: The nameplate.

COMMISSIONER MC ALLISTER: That’s the nameplate value. So, you’ve made some assumptions about what part of that is going to have a peak impact and I just wanted to hear a little bit more about that.

MR. GAUTAM: Oh, yeah, so our total PV adoption or stock in 2024 varies between 4,400 megawatts to just under 5,100 megawatts.

And as far as translating the capacity to peak, we still rely on the CSI EM&V reports. They estimate the peak impacts and we basically use those for our report.

COMMISSIONER MC ALLISTER: Okay, great. Thanks.

MR. GAUTAM: Yeah.

COMMISSION CHAIRPERSON WEISENMILLER: Hi, so a couple of questions. First is when you were doing the forecast did you differentiate between new construction and existing facilities?

MR. GAUTAM: For the residential, yeah.

COMMISSION CHAIRPERSON WEISENMILLER: Okay. And what sort of construction rate do you assume for residential per year?

MR. GAUTAM: Construction rate?

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, so 50,000, 200,000? How many new buildings a year?

MR. GAUTAM: Oh, that's an input from our household model. I don't recall exactly what the annual starts are from there, but that's something that also goes into the residential sector model.

COMMISSION CHAIRPERSON WEISENMILLER: Okay, yeah, it used to be more like 200,000 and I think now it's like 50,000. Hopefully, it's going back up again but, you know, it certainly makes a difference.

The other one -- so, just putting that down, the other question is on existing buildings. Did you differentiate between owner occupied and rented for residential and commercial?

MR. GAUTAM: We didn't get into that kind of detail right now. It is something we want to explore more.

COMMISSION CHAIRPERSON WEISENMILLER: Right. Because I'm assuming any sort of economic cost-effectiveness model really is not that meaningful in rented space.

MR. GAUTAM: Yeah. I mean, this is getting to the spread incentive about --

COMMISSION CHAIRPERSON WEISENMILLER: Right.

MR. GAUTAM: Yeah. That's something we'd like to revisit but right now we weren't able to get to that kind of disaggregation.

COMMISSION CHAIRPERSON WEISENMILLER: Okay. And I don't know, it sounded like in residential you looked at average rates, but not the effective rate design.

MR. GAUTAM: Yeah. Again, this was an issue that we didn't face so much in the last IEPR.

COMMISSION CHAIRPERSON WEISENMILLER: Right.

MR. GAUTAM: But it's kind of coming up and so we want to revise the residential model to kind of look at the different -- the characteristics of the different tiers. You know, I think for PG&E almost half of the CSI customers are on some kind of a time-of-use rates. So, we'd like to kind of reflect that in our analysis.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, I think one of the questions, certainly for the -- any input we get from the PUC on the rate design or net metering side of this equation will be good.

And the other one is just coming back to new construction for a moment. I mean my impression was from the E3 study you were finding that's potentially very cost effective. So, again, you might see a much higher penetration rate of new construction, than we would in existing facilities.

COMMISSIONER MC ALLISTER: Also given that we have, you know, zero net energy by 2020, so they have to have it by 2020. I think they're gearing up for that and some of the big builders are already doing that. Yeah, that's --

COMMISSION CHAIRPERSON WEISENMILLER: It just seems like as we move forward it would be good to differentiate between new construction and existing and ultimate existing to differentiate between owner occupied and rented, perhaps not this year.

But then to start getting some feedback from the PUC on sort of rate design, net metering types of things so that our assumptions here are at least reasonable from your perspective on where it's going.

MR. FLORIO: I mean it's very hard to know. I mean there are competing bills in the Legislature on rate design. And, you know, the Commission has a proceeding ongoing that's kind of looking, from a theoretical level, if we had legal discretion what would we do?

I think there's been talk of a proposed decision by September in that proceeding. I don't know if it's going to -- Commissioner Ferron's shaking his head.

MR. FERRON: I think the study you mentioned --

I think the study you mentioned is not likely to come out until the summer.

MR. FLORIO: Yeah.

MR. FERRON: Which would mean a PD would be by September after that.

MR. FLORIO: Yeah, yeah, so it's -- I mean I know it makes it really hard to try to forecast these things. But, I mean, I'm not sure that using the average rate is so bad given how much things are in flux because, you know, right now there's a huge incentive for upper tier customers to convert. But if the tiers were flattened or eliminated that would go down, but there would be more of an incentive for other people. So how that all sorts out, I'm not quite sure.

COMMISSIONER MC ALLISTER: Well, and you've also got the -- you know, you having financing, different flavors of financing out there that's kind of, you know, increasingly allowing margins to shrink a little bit, and permitting people to make decisions with no money down. So, the pencils are getting sharper and where they actually fall, you know, in the value proposition, and at what rate they're able to make it work I think is very much an open question.

MR. FLORIO: Yeah.

COMMISSIONER MC ALLISTER: I wanted to just follow up on something Chair Weisenmiller said, which was sort of the -- well, when you were talking about, you know, and I agree, the need to sort of consider rented space and owned space differently. And I guess it brought -- for me it kind of brings up a question of, you know, how well do the predictive models and the kind of bottom-up, or the sort of -- you know, the predictive model and sort of actually the marketplace, and how we see it, how do those sort of match up?

And I guess the -- you know, there's two different ways of sort of making some assumptions, you know, going forward, and then just basically extrapolating from current trends.

You know, you do have -- the current trend is you have a distribution of sizes, and people make different decisions, and the sort of rational calculation of cost effectiveness is part of that, but not -- I mean, I'll often argue it's not even the majority of the decision.

And, certainly, people at high tiers have a lot of incentive, but there's a sizing variation that's pretty large.

And so, kind of letting those chips fall where they may and then taking the reality and extrapolating forward is pretty different from applying a predictive model.

So, I guess I would just, you know, ask that as each year goes by, or each quarter and we have better data, so see how those two match up and tweak the assumptions, and maybe flesh them out a little bit more as we go forward so we get a better -- part of that is to get a better idea of what the decision making process actually looks like in reality, so we can capture that in the predictive part of this analysis.

MR. GAUTAM: Yeah, you know, the payback approach is something that we looked at, initially, when we were trying to move away from the simple, kind of trend type analysis we'd done in the past, because we wanted to kind of account for the incentives, reductions in system costs, things like that.

And so the payback approach was kind of the common approach that a lot of other agencies we're using, so that's why we kind of went that route. But, you know, that doesn't mean we're going to just stick with this approach.

As more data becomes available, we would like to expand the model in any way we can to improve it.

COMMISSIONER MC ALLISTER: Thanks very much, very helpful.

MS. KOROSEC: Do we have any questions for Asish from the audience? All right, thanks.

All right, next we have Nick Fugate.

MR. FUGATE: Good afternoon. My name is Nick Fugate and I work with the Demand Analysis Office.

We have five staff presentations remaining this afternoon, one for each of the five major planning areas, utility planning areas.

After each staff presentation we'd like to invite staff from the utilities to come up and make comments, and give their own perspective.

So, I'm going to start this afternoon with PG&E. So, I'll be discussing our planning area results, and talk a little bit about efficiency and self-generation.

As Chris mentioned in his presentation, earlier, we have climate zone results for some of these planning areas, including PG&E, so I'll be going over that.

And then sort of the meat of the presentation will be our comparison to PG&E's forecast.

The utilities filed, back in April, their IEPR demand forms, so we have all of their forecast information and drivers to compare to our own.

So, here we see our electricity consumption forecast. You're seeing all three scenarios and then the 2011 adopted mid case is included as a reference.

Our preliminary forecast starts below our 2011 project by about 2.2 percent.

Consumption in the first year of the forecast dips slightly from the base year. This is partly in response to residential and commercial rate increases, but also because PG&E experienced a slightly warmer than average year in 2012. So, there’s a corresponding dip in consumption in the first year of the forecast, which is normal weather. Chris talked about that.

And then growth in the mid case is right around one percent per year, reaching just over 120,000 gigawatt hours by 2024. You can see that the trajectory is similar to what we saw in our 2011 forecast.

So, here are our peak scenarios. The pattern’s very similar to our consumption forecast. One difference is that you don’t see that same drop in the first year of the forecast relative to the base year.

And while 2012 was a warm year on average, PG&E’s peak temperature wasn’t particularly high that year, so the normal weather adjustment doesn’t have the same effect of bringing down the forecast.

Growth in the mid case is about 1.25 percent a year, reaching just about 29,000 megawatts by 2024. These scenarios reflect staff estimates of non-event-based demand response, committed programs incremental to the 2012 impacts that we saw.

The projected impacts reach around 20 megawatts in 2024.

Also embedded in this are the climate change impacts that Chris discussed earlier, and for PG&E that amounts to about 420 megawatts in the mid scenario and 634 megawatts in the high case.

So, here’s a graph of per capita consumption, which is relatively flat in the near term, but rises in the second half of the forecast period as consumption by electric vehicles increases significantly.

The big drop in the first year of the forecast reflects the combined impact of increasing population and decreasing consumption, so that drives that way down in that first year.

So, here we have a very similar chart to the one you saw in Chris’s presentation. You’ll see almost an almost identical chart a couple more times, just the scale is changing a little bit.

These are our committed efficiency scenarios. They show the combined impact of price effect standards and utility programs. And for PG&E, the sum of these impacts reached 45,000 gigawatt hours. And 16,000 of that represents just committed impacts that are added over the forecast period.

So, here are self-generation peak impacts.

We’re projecting self-gen to reduce peak demand by about 2,100 megawatts by the end of the forecast period and consumption by about 10,000 gigawatt hours.

Most of the increase in self-gen peak impacts comes from -- you know, during the forecast period comes by way of about 2,000 megawatts of additional installed PV capacity.

COMMISSIONER MC ALLISTER: Nick, I’m sorry, just I wanted to go back to the previous slide. I didn’t quite follow. That was a tightly phrased, very precise description that you gave and I think I just didn’t quite take it in.

So, these 16,000 additional gigawatt hours correspond to what, exactly?

MR. FUGATE: So, you can kind of -- well, there’s -- we start at about a little under 30,000 and so just over the forecast period we’re adding about 16,000 gigawatt hours.

COMMISSIONER MC ALLISTER: Okay.

MR. FUGATE: So, by 2024 we’re up at around, you know, 55,000 gigawatt hours.

COMMISSIONER MC ALLISTER: Okay. So, the 55,000 you’re referring to was from 1990?

MR. FUGATE: I’m sorry, 45,000 gigawatt hours.

COMMISSIONER MC ALLISTER: Forty-five thousand was from 1990 cumulative, is that --

MR. FUGATE: Yes. So, well, I mean this is all -- as Chris mentioned, this is all relative to a 1975 baseline. So, this is the impacts of -- you know, if we hadn’t done anything, no standards, no programs, nothing.

COMMISSIONER MC ALLISTER: Got it, got it, got it.

MR. FUGATE: This is how much more.

COMMISSIONER MC ALLISTER: Yeah, so this is from the beginning of time with respect to the Energy Commission.

MR. FUGATE: Right.

COMMISSIONER MC ALLISTER: Okay, great.

MR. FUGATE: Okay, so here’s our climate zone map again. The table in the upper right-hand corner describes the different climate zones that you find in PG&E's territory. So, PG&E's territory is the -- I guess that’s magenta, the color on the map.

So, climate zones 2 and 3 are inland areas. They cover Sacramento and the San Joaquin Valleys.

Climate zone 5 represents most of the Bay Area, so San Francisco, Oakland and Marin County.

And the rest of PG&E's territory is covered by the coastal areas, covered by climate zones 1 and 4.

MR. CASEY: Just a question on climate zone 1. I was just curious, you've got Humboldt area in climate zone 1, then it looks like you have Lassen and portions of El Dorado County as well in climate zone 1, and they just strike me as very different geographic areas.

MR. FUGATE: Yeah, I'm not sure how that gets -- you know, how we allocate to the different climate zone. Well, Chris has --

MR. KAVALEC: Yeah, I'm afraid we need someone with more institutional knowledge than I have to go back years to describe this process.

But, basically, it's the weather patterns are supposed to be similar, even though we have inland areas and coastal areas. But I can get back to you on the specific derivation of these climate zones.

MR. CASEY: Sure, that would be fine. Thanks.

MR. FUGATE: So, here are consumption results by climate zone and we see that the fastest growth in both consumption and peak demand over the forecast period is projected to be inland, in the climate zones 2 and 3.

So, this reflects the expected resumption of migration from coastal to inland areas. This is something that decreased during the recent recession, so it's expected to pick back up again.

And as an example, growth in population from

2013 to 2024, in the mid demand case, is projected to be about 21 and 23 percent for climate zones 2 and 3, respectively.

And when you compare that to climate zones 4 and 5, where you only see an 8 to 4 percent.

Similar results for the peak growth by climate zone. Particularly in the mid case growth is greatest in the inland areas.

Potential climate change impacts contribute to peak demand growth in climate zone 3. The projected increases in annual maximum temperature are highest in that zone, in both the mid and high demand cases.

So, I just threw this chart in here for reference, just so that you would have the numbers in the packet. It shows the first year of the forecast and the last year, and then the average growth rate by climate zone for consumption and peak.

I've also included a link to our website where you can download more detailed results. Also, I mean, you'll find all of our forecast forms there, so just wanted you to have that.

Okay, so moving on to comparing our forecast to PG&E's. PG&E provided us with a managed sales forecast. So, before we could compare forecasts, we had to add back in their demand reductions due to efficiency that was beyond what we considered committed efficiency.

So, PG&E's forecast, it was also for their service territory, whereas ours is for the entire planning area. So, to make the comparison we mostly looked at growth rates.

So, aside from two key differences, which I'll mention in a moment, our sales forecast is similar to PG&E's. We have high growth in the residential sector, less in the commercial, and then a pretty flat industrial forecast.

The big difference is we've found where that PG&E's forecast shows a much higher rate of growth in households and less growth in electricity rates.

So, when we adjust for those differences, we found that our forecasts were, the growth rates were actually pretty close.

So, here's a graphical depiction of what I was just talking about.

So, PG&E's unmanaged forecast has a much higher growth rate than ours, so that's the green bar on the left there.

And then our CED 2013 preliminary, I've got three bars listed there. The blue one on the left is before any adjustment, so that's 0.79 percent growth compared to PG&E's 1.2 percent.

And then each adjustment that we make, one for the difference in household growth and the other for the difference in rate growth, each adjustment that we made brought us closer to PG&E's overall growth in sales.

So, after those two adjustments we were at 1.16 percent.

COMMISSIONER MC ALLISTER: Nick, can you describe the nature of the rate differences between the two?

MR. FUGATE: Yeah, I don't want to get into too much detail about the rates because we've granted the utilities confidentiality for their rate forecasts. I'll just say that, you know, Chris talked about, you know, the statewide rate forecast is -- you know, we're showing a 40 percent increase over the forecast period.

So, I'll say that that was higher than any of the utility forecasts.

And so this is a similar graph, but for the peak forecast. And for peak growth, PG&E's unmanaged service territory forecast shows an average growth of 1.47 percent from 2013 to 2024.

Our preliminary peak growth for the planning area was 1.2 percent. So, we made the same two sort of back-of-the-envelope adjustments for housing and rate growth and that increased our peak growth to 1.57

percent.

So, after that we actually end up being a little bit higher than PG&E's. And the main reason for that is that we showed high growth in peak demand from 2013 to 2014, while PG&E showed very little growth for that year.

So, we'll still be talking with their forecasters to try to figure out what's going on there, see if we can reconcile that last little bit.

MR. CASEY: Nick, just a question on this analysis. I'm a bit unclear what you do with it in the end. It sounds like if you adopt similar assumptions, your CEC model gets you closer to what they're forecasting, but you won't be able to --

MR. FUGATE: Yeah, this is really an exercise in just making sure that we understand the differences, both in methodology and in inputs between the two forecasts, so that we can convey that to decision makers.

MR. CASEY: Okay. And, ultimately, will there be some consideration of whether you might change the assumptions used in the CEC report?

MR. FUGATE: Yeah, that's part of this next process, from going from the preliminary to revised forecast we'll be going over these differences and deciding, you know, which -- you know, which recommendations from the utilities will help us, you know, get closer together, which ones we want to incorporate into our own forecast.

MR. CASEY: Got it. Yeah, thank you.

MR. FUGATE: So, that's all I have for PG&E, if there are other questions?

COMMISSION CHAIRPERSON WEISENMILLER: No, I think that's good. If we could hear from PG&E, now, that would be a good step, but thanks, Nick.

MR. PLUMMER: Hi, Matthew Plummer here with PG&E. With me here today is Ipek Connolly, who's the Manager of our Load Forecasting Group.

Before I turn the microphone over to here for some specific feedback, I just want to thank the Commission and thank staff for their continued collaboration and openness.

I know that everyone, internally at PG&E, has been in extensive conversations on the forecast and just the openness and collaboration has made the process very easy, and very smooth, and I look forward to this as a continuing conversation.

So, with that --

MS. CONNOLLY: Thank you. My name is Ipek Connolly and I'm the lead of the forecasting group at

PG&E. I would like to also thank the Commission for allowing us to make comments on this process. And I also want to thank staff for both producing a very comprehensive, very well thought through and very well documented forecast that will help us chart our future in much better ways.

As well as thank especially for the collaborative process, for the time that they've spent going over some of the details of the high level results with us that helped our understanding of where we may have some differences.

And we will be looking forward to continuing to work on those issues.

And today I'm going to be making a very preliminary, high level comments based on what we've been able to gather so far.

So, just like the staff explained, there's a step involved in going from what's presented in the CED today to what we consider our distribution area forecast.

So, we tried to make those adjustments and also tried to bring here some sense of what the two forecasts looked like, at least at a high level.

So, this first chart is what we consider our distribution area forecast, which is shown by the blue line. And the red line is the staff’s forecast for the planning area, for PG&E planning area. So, there’s a difference in the levels, that’s one of the differences.

The other is, again, as mentioned the staff report does not include the full extent of what we consider projected energy efficiency improvements. And we tried to reflect that in our -- the way we understand it and that’s subject to confirmation. And that’s shown by the dotted line.

And after making those two adjustments we see that we’re actually pretty close in terms of expected growth rate over the next -- from 2013 to 2024. So, this is compounded annual growth rate.

So, staff projects about .52 percent per year growth and our projection comes to about .74 percent per year.

There are many differences in terms of how we approach this forecast. There’s differences in the models. There’s differences in chosen drivers for some of the sectors. There’s differences in the sources for those drivers and assumption.

So, when we dig down into the forecast we do recognize that there’s a lot more differences than that. But it is -- at this level it makes us feel good that we’re this close in terms of you, you know, at the end of the day where we expect to end up.

Now, the one biggest factor that contributes to this difference in the growth rate is the projected increase in electric rates that's underlying the staff's projections versus our own projections.

And I'm very pleased to hear that staff intends to look at that and work with all parties involved in the effort to come closer in terms of those expectations.

I know we have -- this is not an area that we can comfortably talk and get into the details here because it involves a lot of confidentiality but there's a couple of things that I can point out.

One is when we look at historically the rate increases for the last 10 years, 15 years, and this is also in staff's report, the rate increases in inflation adjusted, real terms have been almost steady, no exceeding the inflation rate.

In general, this is our expectation and this is our goal. We will work towards this goal.

In terms of producing this forecast we made a very generic assumption, which is not necessarily consistent with -- you know, we will provide some requirements related inputs, so those numbers are slightly different than what we used starting this forecasting period.

But our assumption was inflation plus one. And the staff's underlying electricity rate forecast is inflation plus, I believe, 2.8. So, if CPI is about, you know, 2.8 to 3 percent it implies annual growth rate in exceedance of 7 percent, or 6 percent.

So, we consider this to be a little on the high side and we're encouraged to hear that this will be reviewed.

Another area that, again, I want to emphasize here is this practice of excluding some part of expected energy efficiency savings from the forecasts. That creates a lot of confusion in understanding a lot of inefficiencies in information exchange for decision makers, or public, for other users who don't, on a day-to-day basis work with these numbers. They can get, you know, information that may not be accurate, so I'm very pleased to hear that staff is moving in that direction and we support this.

I also would like to commend staff for developing econometric models and using them along with the end-use models to inform their forecasts. This is an area that helps us tremendously in terms of, you know, having a better understanding from what we're getting from both of these approaches and being able to incorporate them into what ultimately comes out of this body, and for us also to use in our future projections.

So, this is all I have to say and thank you again, very much. And we will continue to work with staff and we're very interested in getting into the details.

With that, if you have any questions, I'd be happy to answer.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, a couple questions. First is Nick talked about what he thought was having the relative difference, causing the relative differences. Is that -- you know, is your conclusion similar to his that it's pretty much rates and households?

MS. CONNOLLY: Those are the main two, but then we haven't really gone into the details.

COMMISSION CHAIRPERSON WEISENMILLER: Right, sure.

MS. CONNOLLY: I did not notice, for example, in the commercial sector we're very different.

COMMISSION CHAIRPERSON WEISENMILLER: Okay.

MS. CONNOLLY: You know, I suspect that, again, there are -- I was looking at numbers without the incremental energy efficiency. First of all, that will bring it down and I don't know exactly how much.

The high electric rate forecast is going to cause that to be diverging, as well as elasticity. So, I’m not sure, you know, when we look at the details whether we’re consistent and we have consistent views on what the divers are, and what’s expected for those drivers.

But I know we’re very close in the industrial sector. I know agricultural, they’re expecting a continuation of the recent increases that we’ve been seeing and so they’re forecasting higher than our forecast, which I kind of like that. But we’re looking at a longer term forecast.

I think for the short term I know that with the drought we’re going to probably see a little higher agricultural sales than what one would expect in a normal weather. But then the question is how do we extend that for the long term.

But agriculture is a small portion of the overall load. Yeah, so --

COMMISSION CHAIRPERSON WEISENMILLER: Okay. What about, you know, staff talked earlier about their self-gen forecast, at this stage do you have any comments on that methodology?

MS. CONNOLLY: I think we were very close with the previous numbers that we’ve looked at and, again, there are some differences in underlying assumptions, but I am not aware of any significant issues that I'm aware of.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, and my recollection is, this is the first time I've been in an IEPR where PG&E's said their rate forecast was confidential. I'm just trying to understand when that occurred and the rational, if you know.

MS. CONNOLLY: I'm afraid I don't have that background.

MR. PLUMMER: We can get back to you on that.

COMMISSION CHAIRPERSON WEISENMILLER: I guess in terms of the peak demand numbers, your next chart, if you want to skip to --

MS. CONNOLLY: Yes.

COMMISSION CHAIRPERSON WEISENMILLER: -- if you have any other comments on those.

MS. CONNOLLY: Peak demand is also after making all the adjustments we're seeing that we're very close. In fact, I'm showing two decimals here to show the difference, but in actual fact they can be all rounded up to .7 percent per year.

The staff forecast is slightly lower growth than ours.

And then I'd be interested in maybe looking into the weather correction that was done to explain the 2012 peak situation because I am seeing that there's quite a significant increase for 2013. We don't have a similar increase. That's why the growth rates that I'm citing here are 2013 onwards, so that whole weather correction thing doesn't distort this information.

COMMISSIONER MC ALLISTER: So, just a couple of things. I guess you mentioned that, you know, you have -- and I understand you have goals. You know, you want to sort of do the best job you can as a utility, and sort of keep the rate escalation down, and still meet demand and everything.

I guess I wanted to kind of -- you know, it's great for the individual components and assumptions where we can figure out where there are differences and come to agreement, or kind of agree to disagree. But I guess, you know, there is a little bit of difference going on here where the Energy Commission is really looking cold and hard at the numbers and looking at the underlying drivers, and that kind of stuff.

And so to the extent that that -- I mean I think that's part of the sensitivity. I assume that's part of the sensitivity about rates and some of the assumptions there because it's got a business imperative for you, which I understand.

But to the extent that there are sort of goals built into your forecast, you know, it would be nice to know sort of where those fall out so that where we are just talking about numbers that are sort of checkable in the world that we can agree on those.

And then sort of where we have kind of different views, or goals, or incentives maybe we can also agree on those.

So, you know, your forecast, you know, you're going to try to -- I guess I just want to make sure that where we differ and why we differ is important to keep in mind and be explicit about as much as possible.

MS. CONNOLLY: Yes. We plan to work with Commission staff on this, clearly recognizing that, you know, cost information we can't exactly share.

COMMISSIONER MC ALLISTER: Yeah.

MS. CONNOLLY: But we can certainly talk about, in more specific terms, you know, our view of maybe the gas prices.

COMMISSIONER MC ALLISTER: Right.

MS. CONNOLLY: Not talking specific numbers, but in terms of prices.

I can say that we're probably seeing them lower than what's underlying the staff's projections.

COMMISSIONER MC ALLISTER: Right, okay.

MS. CONNOLLY: Again, carbon, you know, trading, those costs, they're coming down. The cost of renewables, they're coming down. So, there's a lot of downward movement that perhaps maybe due to the timing of when the prior E3 model was run -- I'm not sure, I'm speculating at this point.

COMMISSIONER MC ALLISTER: Right.

MS. CONNOLLY: Maybe those latest developments haven't fully been reflected in those projections. We're looking forward to getting into all those specifics in terms of, you know, coming up with something that's close to what our expectation is.

COMMISSIONER MC ALLISTER: Great. So, yeah, I appreciate that and I think that's a really valuable discussion for us and for you.

The only other observation I'd make is that, you know, as we all saw in the presentation on the PV and the DG part of the forecast, the modeling and everything, the data came from the CSI database by and large. And that has, I think, been a very valuable, is a very valuable resource for the State so that we can track market developments, trends and equipment, and installation characteristics, and installed cost, and a myriad other things.

So, I wanted to just encourage PG&E and the other utilities to work with the PUC, certainly, but find a way to ensure that that resource continues going forward because I think that would be a huge shame if we got to 2015, or now in the case of residential systems where there's no more incentives and so, therefore, if we don't keep populating that database and we lose the market trending, we lose that information going forward and I think that would be a big shame. The State has invested a lot in it and it has helped the marketplace thrive in ways that have really helped our economy and diversified our supply resource.

All sorts of discussions about rates, and net metering, et cetera, et cetera, but fundamentally we really need that data in the public sphere going forward and I would strongly encourage the utilities to find a way to make that happen.

Thanks very much for your presentation, I really appreciate it.

Anybody else have any comments?

MR. FERRON: Yeah, I just have a quick question. I'm not sure if I understand the difference between the red and the blue line, at least historically. Is that just the definition of -- or the difference between the definition of your service territory and the way the Energy Commission looks at the same geographic region?

And so is that difference just the --

MS. CONNOLLY: Yeah, PG&E area includes other distribution utilities.

MR. FERRON: Okay.

MS. CONNOLLY: For example, City of Palo Alto, my former --

MR. FERRON: Okay, got it. All right thank you.

MR. FUGATE: So, I just wanted to thank PG&E for that and just say that we're certainly looking forward to working with them as we revisit some of these issues for the revised forecast.

Okay, so moving onto the Southern California Edison planning area. And we have -- the outline in the presentation is identical, so we'll just go right into our electricity consumption.

So, unlike with the PG&E forecast, the base here for Edison actually starts at roughly the value projected by the last forecast.

Again, due to rate increases and normal weather we drop below CED 2011 in that first forecast year.

The trajectory for the mid case is similar to what we saw in CED 2011. The preliminary mid case average is just under 1 percent growth per year and reaches 112,700 gigawatt hours by 2024.

In Edison's territory 2012 was a hotter than normal year, both on average and at the extrema so we have that same dip in the first year of the forecast.

And the mid scenario grows at a rate of 1.32 percent a year to reach 25,200 megawatts by 2024.

These scenarios also reflect demand response estimates, roughly 33 megawatts by 2024.

And also, climate change impacts add up to about 400 megawatts in the mid case and 640 megawatts in the high case.

So, for per capita consumption it’s a similar graph. We see that same initial drop due to the decreasing consumption and increasing population in that first year of the forecast.

So, we have nearly 2,000 gigawatt hours of consumption by electric vehicles in the mid case and that drives up per capita consumption towards the end of the forecast.

So, in Edison’s territory, over the forecast period we’ve got 13,000 additional gigawatt hours of savings projected due to price effects, and standards, and utility programs. It brings the total to nearly 35,000 gigawatt hours by the end of the forecast.

For self-generation, we’re projecting a reduction in peak demand by over 1,500 megawatts and a reduction in consumption by about 7,800 gigawatt hours.

Again, most of that reduction comes from PV. The peak reduction, that is, comes from PV. Roughly 1,500 megawatts of installed PV capacity over the forecast period will reduce the peak demand by 450 megawatts. That’s in the mid case.

So, back to the climate zone map and this time we’re looking at the yellow area for Edison. So, this is made up of climate zones, the inland climate zones 7 and 10. So, that covers the Southern San Joaquin Valley, plus Riverside and San Bernardino Counties. And also, the coastal climate zones 8 and 9, which are Long Beach, Orange County, Ventura County, and the Inland L.A. Basin.

So, here’s growth in consumption by climate zone. The story here is pretty similar to what we saw in the PG&E analysis. The fastest growth in both consumption and peak demand over the forecast period is predicted to be inland, again due to migration that will continue from coastal to inland areas.

The growth in population in the mid demand case is projected to be 28 and 19 percent for climate zones 7 and 10. That’s compared to 7 and 9 percent for climate zones 8 and 9, the coastal climate zones.

And the inland climate zones see higher peak growth, as well. That’s due, again, in part to climate change considerations. Potential climate change impacts contribute to faster peak growth in climate zone 7, in the mid demand scenario. And that says annual maximum temperatures are highest in that zone.

Again, I put this in here for your reference. It’s the same link to all of our forecast forms, including more detailed reports of the climate zone analysis.

So, now the comparison to SCE’s forecast. They provided us with a managed service territory sales forecast, so in order to line up our forecasts we first had to add back in incremental efficiency impacts to make it unmanaged, and that allows us to compare growth rates.

The key difference in this case seemed to be mostly rate growth, ours is higher and also, electrification.

SCE included about a little over 5,000 gigawatt hours of additional electrification by 2024, of which 3,400 gigawatt hours is attributable to electric vehicles.

Our preliminary forecast mid case includes a little less than 2,000 gigawatt hours by the end of the forecast period. And that’s all electric vehicles and we don’t have any additional electrification impacts.

For the revised forecast, the Fuels Office will be providing a new EV forecast, as well as estimates of additional electrification that may possibly bring our forecasts a little bit closer together in that regard.

MR. FERRON: I’m sorry, could you just repeat those numbers again?

MR. FUGATE: So, for the electrification Edison had 5,048 gigawatt hours of additional electrification and 3,430 gigawatt hours of that is electric vehicles.

So, that’s compared to our electric vehicle forecast, the mid case has 1,948 gigawatt hours.

COMMISSIONER MC ALLISTER: So, Nick does that -- I guess I can confer from that that PG&E and you were on the same page with respect to electrification and that wasn’t a big different between the two, it wasn’t an element of difference in PG&E's case?

MR. FUGATE: I don’t recall that electric vehicles were a significant difference. And I also don’t recall if PG&E had any additional electrification elements to their forecast.

COMMISSIONER MC ALLISTER: Okay.

MR. FUGATE: No.

COMMISSIONER MC ALLISTER: Yeah, yeah, I mean certainly Edison has more of a focus for electrification than PG&E, but a big territory. And, presumably, the

Bay Area has some electrification going on, I would imagine. And I'll look to see what SDG&E's situation is there, too, because they're anticipating quite a bit, so thanks.

MR. FUGATE: So, comparing our growth rates in our consumption forecast -- or sales forecast, we made some more back-of-the-envelope adjustments to our forecast, increasing it once as if we had used Edison's rate projections and then, again, by adding in their incremental electrification estimates.

So you can see in this chart the SCE service territory forecast for unmanaged sales shows average annual growth of about 1.4 percent per year, from 2012 to 2024.

Our forecast grows at a rate of .83 percent over that same period. That's before we make any adjustments.

And after the two adjustments, one of the rates and one for electrification, we're much closer at 1.3 percent.

The remaining difference could be attributable to our differing population projections. We're using Global Insight's projection for the mid case and Edison is using a combination of Global Insight and Moody's, and so the combination of that gives them a higher population estimate.

So, for peak demand SCE actually provided us with a forecast that corresponded to our SCE planning area, so we were able to do a more direct comparison.

We still had an estimate of unmanaged peak by -- we had to estimate unmanaged peak by adding in incremental peak efficiency impacts. So, after that SCE's peak demand was 27,147 megawatts for 2024. That's compared to our unadjusted forecast, which was 25,277 megawatts.

So, we're quite a bit lower. We make the first adjustment for the rate projection differences and then another for electrification, and that brought us up to 26,375. So, we're still around 3 percent lower than the SCE unmanaged forecast.

So, a good part of the remaining difference happens because our forecast shows a decline from 2012 to 2013, so that first year of the forecast. And that's in contrast to SCE, which shows a significant increase in that year.

So, it seems this has to do with our respective weather data and corresponding adjustments that we made to normalize the forecast.

And our weather data and weighting scheme yields a decrease in maximum temperatures from 2012 to 2013, but SCE's analysis showed the opposite effect. So, it's something that we're going to have to discuss with SCE's forecasters and try to see if we can get on the same page.

So, with that I'll ask for questions.

MR. CASEY: Nick, just a quick question. At the very beginning of your presentation you mentioned a number for demand response. Do you recall what it was?

MR. FUGATE: Yes, 33 megawatts. That's incremental to whatever demand response we saw in 2012.

MR. CASEY: So, over the next ten years, with a 26,000 megawatt peak load, we're projecting 33 megawatts of incremental demand response?

MR. FUGATE: Yeah, relatively -- I'm sorry, yes, Chris is reminding me an important qualifier is that it's a non-event-based DR. So, like --

MR. CASEY: Embarrassing nonetheless.

MR. FUGATE: I think it's also another thing I didn't mention about that is that it's sort of similar to our committed efficiency programs analysis. We're not making any assumptions. We're not trying to guess what DR is going to look like.

So, like if you actually look at our year by year estimates of DR program impacts they increase, I think for the first couple of years of the forecast, and then we just hold them constant after that.

COMMISSIONER MC ALLISTER: So, this is an area where, obviously, we hope that the future looks different from the forecast, but there would have to be some discontinuity there that we somehow design programs to achieve, right.

So, I think this is sort of part of the inherent frustration of forecasting is, you know, we kind of have goals for what we want to see, but we can’t assume that it’s actually going to happen if it’s not based on past experience.

MR. FUGATE: Any other questions before we invite Edison to speak?

MS. SHENG: Good afternoon. My name is Hongyan Sheng. I’m the Manager of Long-Term Demand Forecast Group at Southern California Edison.

Joining me is Johanna Benson, who’s our Senior Load Forecaster at SCE.

First of all, I’d like to thank Commission for providing this open forum. I find it’s very engaging.

Also, I’d like to especially thank Chris Kavalec and his team at CEC, who are taking the lead in working very closely with SCE forecasting team over the last couple weeks in reviewing their long-term preliminary forecast, and help us reconcile the differences.

In general, I think SCE is in agreement with CEC’s assessment of our differences. As a result, I think we were able to narrow down to a few major areas that we think we’d like to still look into further and working with CEC more closely to continue to reconcile those differences.

So, I’d like to just highlight those few remaining areas.

The first is in terms of the electric rate projection. I think we heard from PG&E's discussion, as well, we also saw that the electric rate forecast assumption in CEC’s forecast looks relatively higher than what SCE assumes. So, we will talk about that a little bit more.

And another area that we’d like to talk a little bit about is the residential sector forecast which, you know, household is the main driver in CEC’s forecast. So, we’d like to talk about the forecast assumption and impact, and in terms of how it’s affecting our forecast differences.

Also, we’d like to talk about the peak demand forecast differences, which we’ve seen also driven by our peak temperature estimation differences. This is an area, as Nick mentioned, you know, as we recognize there may be differences in different things and we’d like to look into further with CEC, together.

So, first in terms of electric rate projections, you know, we brought the chart here to show how volatile natural gas prices -- natural gas price forward curves were during the last five or six years.

As you can see, that as a major input the rate projections, whether we use a more updated natural gas forward curve versus using a more outdated natural gas forward curve the differences could be pretty significant. And we've understood this is potentially the main driver for the rate forecast.

So, we'd really like to recommend that all the stakeholders get to review the input assumption to the rate forecast model and ensure that we use the latest information and also, you know, the reasonableness of the input assumption.

We also recognize that, you know, as the starting point the actual 2012 rates may look differently if we were to use the actual 2012 rate versus the earlier estimate.

So, to the extent possible we would also recommend CEC to obtain the most updated 2012 rates from everybody so that we have the right starting point possible.

Also, I recognized earlier Commissioner Ferron made a comment in terms of the output of the rate forecasting model. In terms of the shape of the rate projection we also recognize that, you know, the rates increase in the near term may look differently than in the longer term.

So, you know, I think there's also differences we'd like to reconcile with CEC in terms of the reasonableness of the output of the rate forecast model.

So, to the extent possible we would really appreciate that we can have the stakeholder review of the rate forecast model CEC will be using and allow all the stakeholders to provide comments and ensure that the reasonableness of the inputs to the model, the reasonable design of the model and the output, as well.

The next area we'd like to highlight is in terms of our residential forecast. You know, this graph shows CEC's household projection compared to SCE's housing staff forecast. Both are the main basis for our residential forecast.

As you can see, for the period of 2013 to 2024, the future forecast period, in general the growth rate in our housing projection are higher than CEC's household projection.

One thing I'd also like to point out, which looks interesting to us, is looking at the incremental household history between 2007 and 2012 we saw that, you know, there's some irregularities in the data series, so it was compared to the housing start historical series it's relatively harder for us to see the trend.

If we were to look at housing start, you know, historical part, we can see that they're in the recession, housing start really dropped significantly. And post-recession there is a gradual recovery.

And based on the average Global Insight and Moody's projection we really see in the near term there is going to be a more significant increase in the housing start.

Another way we looked at the household projection from CEC is the household size forecast. Even though we have not utilized such forecast, but just simply looking at the household size forecast I know Chris mentioned, earlier, that the CEC utilized a lower population forecast this time.

But at the same time we think the household size forecast also matters as we can see that in CEC's household forecast -- household size forecast, in general they are projecting an increase in household size in the next ten-year period.

We have not done enough research or analysis, you know, to really assess the reasonableness of that, but we definitely think that assumption of the long-term growth trend in the household size matters in the overall household forecast.

The last area we'd like to highlight is part of the reason that drives our peak demand forecast difference between CEC and SCE. As we recognize, in CEC's peak demand forecast CEC is showing 2013 SCE planning area peak demand lower than that of 2012. And we recognize that's due to how we look at the peak temperature.

We have found that CEC defined 2012 peak temperature as being slightly above normal, but according to our peak temperature measurement, SCE found that the 2012 is slightly below normal.

So, that's to the differences, seeing our projected 2013 peak demand. As a result of the different starting point, you know, using a lower starting point of 2013 peak demand that has a tendency to raise the average annual peak demand growth rate in CEC's peak demand forecast.

So, we have started working with Chris's team to investigate the sources which potentially lead to those differences. You know, that potentially includes, you know, how we use the weather data, what weather station we use, and how we weight them, and how we calculate the peak temperature differently.

So, in general, we'd like to work in the highlighted areas with CEC team before they finalize the forecast.

Also, I'd like to highlight is that the -- as PG&E, Ipek, you pointed out, we also recognize that when CEC get to incorporate uncommitted EE in the forecast that will really provide more direct and meaningful comparison between -- for our forecast.

So, we'd really like to see that effort going forward.

Also, one comment I have is, you know, I'm really encouraged to see the climate change impact that CEC's started working on. At SCE, we haven't really started this effort but, definitely, I'd like to recommend that the CEC to allow and also help utilities to look into the climate change impact study, and how that's being done.

That's my general comment.

COMMISSION CHAIRPERSON WEISENMILLER: A couple of questions. First of all, Nick had noted a difference in electrification between our forecast and Edison's. Did you have a similar conclusion or, again, was it just the four things on the last page?

MS. SHENG: Yes, I think the assessment is right. I think that we recognize the main difference is coming from the fact that the CEC hasn't incorporated the electrification forecast update for SCE. And we believe that, you know, with that update later our forecasts on that -- in that area will be closer.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, okay. It's just like the last time my recollection was the differences between the two forecasts, a lot of it was electrification. I thought there may have been some differences in the commercial sector, also.

So, I don't know if the commercial is now in pretty good agreement or subject to, you know, future analysis?

MS. BENSON: There's a couple things that make it difficult to compare commercial forecasts and part of that is because we forecast by revenue class, and the CEC forecasts by NICS Codes.

So, we can try to lump a few things together. For example, we forecast commercial and public authority, so we can try to lump those in together and see if we get a little closer. But we can't make an apples-to-apples comparison.

But, yeah, I would say on the commercial side it's improved over last time. If I remember, a couple of years ago we had significant differences. The gap is starting to close a little bit there.

COMMISSION CHAIRPERSON WEISENMILLER: Okay. Now, this is the first time we've tried to do the disaggregated forecast. I don't know if Edison has any sense of its load growth on how much is going to be inland versus coastal?

MS. BENSON: Yes, actually we -- I don't have any numbers with me, but we do our residential forecasting based upon counties --Okay. Now, this is the first time we've tried to do the disaggregated forecast. I don't know if Edison has any sense of its load growth on how much is going to be inland versus coastal?

MS. BENSON: Yes, actually we -- I don't have any numbers with me, but we do our residential forecasting based upon counties --

COMMISSION CHAIRPERSON WEISENMILLER: Okay.

MS. BENSON: -- because of the geographical differences in terms of housing size, temperatures, income, that sort of thing. So, that's one of the ways that we can identify and segregate those areas to take into consideration those effects.

So, at least for the residential side we do disaggregate.

COMMISSION CHAIRPERSON WEISENMILLER: Okay.

Now, if you go back to your slide 5 -- excuse me, 3 for a second?

Yeah, now when is the last point on that graph that's real data versus forecast? Is it 2012 or earlier?

MS. SHENG: I think 2012 is the last actual data point.

COMMISSION CHAIRPERSON WEISENMILLER: So, basically, the increases are all forecasts as opposed to much data at this stage.

MS. SHENG: Right.

COMMISSION CHAIRPERSON WEISENMILLER: Now, do you expect that growth to be more inland or coastal or, again, it's something that you'll deal with later?

MS. SHENG: I would suspect more inland.

COMMISSION CHAIRPERSON WEISENMILLER: Okay, so sort of back to the Inland Empire. Okay, that's all I have.

COMMISSIONER MC ALLISTER: I wanted to just get a better sense of the weather issue. I think, I believe you were implying that it was more of a methodological issue than a data issue, but I think it's related to this movement inland and kind of getting the weather data assumptions, and the actual data, and sort of working with that data process issues, getting those talked about and resolved where there are differences.

So, could you talk about that process?

MS. SHENG: At this stage, we just started investigating the sources of differences and, really, it’s potentially not just methodology, but potentially the way we use different weather stations, for example.

And so the analysis we have done is still in the preliminary stage.

COMMISSIONER MC ALLISTER: Okay.

MS. SHENG: It may not necessarily be the methodology difference, it could be purely, you know, which weather station we utilize and which weather data we use exactly.

COMMISSIONER MC ALLISTER: Great. So, there’s a data quality, potentially a data quality evaluation that needs to happen.

MS. SHENG: Right.

COMMISSIONER MC ALLISTER: Okay.

MS. SHENG: We’d really like to reconcile those differences.

COMMISSIONER MC ALLISTER: Okay. Well, I think that’s good work so, thanks, that can move forward along with everything else.

MR. CASEY: Yeah, actually, I was going to raise the same issue Commissioner McAllister did on the -- if a third data point helps on this, in the ISO's summer assessment report for this year we looked at 2012, and in Southern California it was above normal weather event for the peak. So, I'm sure you could contact our staff if you wanted to understand our weather methodology, but it is yet another data point you can use to try to resolve your discrepancies.

MS. SHENG: Yeah, that would be great. I will definitely be looking to CAISO's assessment, as well.

COMMISSIONER MC ALLISTER: Great, thank you very much. Or, Chris, did you want to add something?

MR. KAVALEC: Yeah, on this weather issue, it's always a question of what weather stations you use in a large area like Edison's, and what weights do you attach to those weather stations. Do you use air conditioning weights, or population weights, and so on.

And so, I think what we hope to do is kind of test different stations and weights to see what gives you the best fit with peak demand, and maybe that would be a step in the process of reconciling our two different approaches.

MS. SHENG: Yes. Yeah, this was just to start off our collaboration effort. I'm pretty confident that when we get to work with Chris's team more, we can reconcile the difference more.

COMMISSIONER MC ALLISTER: Yeah, I want to just -- I mean this is really -- you know, this sounds highly -- it is highly technical, highly wonky, lots of major analysis associated with this. But this really is an important, a super important issue because long term our State is evolving in a very clear direction, and it has a lot to do with weather and it has a lot of renewable resources that are available in some of these local capacity areas.

And so, getting an understanding of how to model these things I think is really fundamental, and it will be great when we're moving -- you know, we're basically in agreement and moving in the same direction on this. So, I really appreciate this.

Any other questions?

MR. FLORIO: Just to follow up on that same point, it is a little striking that there's not even agreement on whether 2012 was above or below normal. But is that a .1 percent above versus .1 percent below, or is it a large spread in absolute value?

MS. SHENG: It's hard to put absolute term. I think it's not that significant difference. But in terms of weather normalization it does make a big impact in terms of direction.

MR. FLORIO: Yeah, okay, thank you.

MR. FERRON: I'm sorry, I have a question. I'm just puzzling over the EV projection because it's a big difference between the CEC and Edison's projection.

And I just did a back-of-the-envelope calculation to put it in context, and maybe I got the calculation wrong, but 3,400 gigawatt hours is roughly a million cars on the road over the course of a year. So, that's a pretty big difference.

Can you shed any more light on what the assumptions are or maybe it's a question to be answered offline.

MS. SHENG: I can't remember all the numbers exactly, but it's probably in the magnitude of if we were to look at one out of 50 households having an electric vehicle in the next year or two, it will grow to one in 10 household by 2020 or is it 2030?

MR. FERRON: Well, if that's the case, because there -- again, I looked what's out there and there's 22 million cars on the road, 32 million if you throw in trucks, so 10 percent of that could be. It's a lot, all right. I was just doing a sanity check.

COMMISSION CHAIRPERSON WEISENMILLER: No, that's good. Actually, the last time I think what we were finding was there's the EV forecast and we said we'll have a transportation workshop later and, hopefully, have the Air Board with us in that conversation.

But then there’s also a lot of gearing of electrification to the ports, Long Beach and L.A.

MR. CASEY: Right.

COMMISSION CHAIRPERSON WEISENMILLER: And then I think the last time, too, Edison was looking at some of the industrial loads being electrified, so we’ve gotten more convergence.

But in the South Coast footprint they’re seeing a lot of shift to electricity.

MR. FERRON: All right, thanks.

COMMISSIONER MC ALLISTER: Okay. Well, if there are no further questions --

MS. SHENG: Thank you.

COMMISSIONER MC ALLISTER: Suzanne, do we want to open up -- well, we want to wait until the end of these presentations to open it up.

Okay, great. Thank you very much. That was helpful, I appreciate it.

So, back to Nick.

MR. FUGATE: Okay, so moving on to San Diego Gas and Electric planning area. We have a slightly shorter agenda for this one, just because SDG&E, the planning area is comprised of only one climate zone, so we won’t have that analysis to go through.

So, here's our consumption forecast for San Diego. We start about 2.2 percent lower than projected by CED 2011. It was a slightly warmer year on average in 2012, which keeps consumption relatively flat in the first year of the forecast.

And our mid scenario grows at 1.41 percent to reach 24,700 gigawatt hours by 2024.

For peak demand our analysis shows that peak temperature for San Diego in 2012 was actually a little cooler than normal, and so our peak forecast shows growth in that year, from 2012 to 2013.

Our mid scenario grows at 1.41 percent over the forecast period to reach 5,432 megawatts by the end of the forecast.

The climate change impacts embedded in the peak forecast add 80 and 148 megawatts in the mid and high scenarios, respectively.

So, here's per capita consumption again. We're using the same EV forecast that we had in CED 2011 and at the time sales data seemed to indicate that SDG&E's territory had a significantly higher adoption rate for electric vehicles compared with the rest of the State. So, their territory received a relatively high portion of the incremental consumption.

So you can see here that it had a significant impact on per capita consumption. So, this attribution may change as we reexamine our EV projections for the revised forecast.

Here we have committed efficiency impacts, again. This time 3,400 additional gigawatt hours of savings over the forecast period, bringing the total up to 8,700 by 2024.

So, self-gen is expected to reduce peak demand by about 380 megawatts and consumption by over 1,700 gigawatt hours. PV is, again, the big player here in reducing peak demand. Nearly 600 megawatts of installed PV capacity over the forecast period is expected to reduce peak demand by over 200 megawatts in the mid case.

So, no climate zone analysis. We'll go right into the comparison to SDG&E's forecast.

They provided us with an unmanaged sales forecast so there was no need for us to add back in any efficiency reductions.

So, in keeping with the theme this afternoon, the biggest difference between our forecast drivers and SDG&E's is in the rate assumptions. Ours was higher.

And we saw some minor differences. Specifically, we projected higher residential growth than commercial, and SDG&E's forecast had it the other way around. This could be a symptom of the rate discrepancy since our commercial model has a high price elasticity that drives consumption down as rates increase.

In any case, when we make the same rate adjustment we did for the other planning areas, our sales forecast lines up pretty closely with SDG&E's.

You can see our sales growth starts out lower, about 1.15 percent, versus San Diego's 1.35 percent. The rate adjustment, though, brings our growth up to 1.36 percent.

SDG&E's unmanaged sales forecast is 23,526 gigawatt hours in 2024, while our rate-adjusted projection is 23,548. So, we're -- I mean we're right there.

So, the peak forecast, both SDG&E's peak forecast and our rate-adjusted peak forecast appear to grow at similar rates, just over 1.4 percent. However, these are calculated from 2013 to 2024 and they don't include an apparent discrepancy we have between our forecasts in the first year.

I'll say a little bit more about that in a second.

When we consider the absolute numbers, SDG&E's forecast for 2024 is 5,388 megawatts, while our rate-adjusted projection is higher at 5,527 megawatts.

So, we have the same issue with growth projection from 2012 to 2013 that we saw on the SCE comparison, only this time it’s in the other direction. We show relatively low maximum temperatures in San Diego, in 2012 so, reverting to the historical average for 2013 means an increase in peak.

SDG&E, though, shows almost no growth from 2012 to 2013 and that’s something we’ll want to look at a little bit more with SDG&E’s staff.

So, any questions from the dais?

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, I guess the one question I had -- I mean, I’ve heard from Jim Avery that the SDG&E peak is shifting over time to later in the day. I don’t know if we pick up any of that sort of impact. I assume it’s -- I don’t know if it’s the loads or just the PV impacts sort of whacking down things.

MR. FUGATE: I don’t know. Do we --

COMMISSIONER MC ALLISTER: Well, maybe to put it another way is the -- how much does the peak coincidence of PV, for example, vary across service territories, so PG&E versus Edison versus SDG&E? Because part of that’s a function of when the peak actually comes.

MR. KAVALEC: Yeah, so -- well, San Diego typically has an earlier peak, to answer one of the questions, compared to PG&E earlier in the day, and Edison.

But in terms of the impact of PV on peak, we haven’t looked at that issue, specifically, but I understand San Diego has, so they can tell us what they’ve found when they make their comments, I hope.

COMMISSION CHAIRPERSON WEISENMILLER: Okay, and my other question was just have you considered splitting San Diego into two climate zones?

MR. KAVALEC: Yes.

(Laughter)

COMMISSION CHAIRPERSON WEISENMILLER: And the reason for your decision?

MR. KAVALEC: Yeah, and the problem is always breaking up a county in terms of economic, and demographic, and other data. But I think it’s warranted because there’s been so much growth inland. Ten years ago maybe it wasn’t such a big deal, but so many people are moving east, so we definitely have that under consideration.

COMMISSIONER MC ALLISTER: the one thing that I noted was you mentioned that there was relatively high attribution of EV or of electrification to SDG&E territory and that might change.

j MR. FUGATE: PVs in particular.

COMMISSIONER MC ALLISTER: PVs, yeah.

MR. FUGATE: Yeah.

COMMISSIONER MC ALLISTER: And that that might change. I guess, could you dig that out or unpack that a little bit.

MR. FUGATE: Perhaps SDG&E's forecasters can discuss that, too. That came up in a conversation we had with them a couple weeks ago, that things were looking a little different.

COMMISSIONER MC ALLISTER: Okay, so adoption presumably has slowed down and maybe we'll hear that.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah, I think what happened the last time, when we adopted it, was when a lot of the rollout were really targeted to SDG&E so they could get some experience. So that, you know, again, a year or two when we were going through this, you know, they did have a proportionately high level of EV. Now, whether it's continued or not we'll find out.

COMMISSIONER MC ALLISTER: Great. Well, I don't have anything else. Why don't we invite SDG&E? Great.

MR. VONDER: Thanks. I'm Tim Vonder with the forecasting staff, and Ken Schiermeyer here, he's also with our forecasting staff.

COMMISSIONER MC ALLISTER: Is that mic on or maybe you could just -- there we are.

MR. VONDER: Tim Vonder with SDG&E's forecasting staff and Ken Schiermeyer with the forecasting staff. Ken's our Chief Forecaster.

Nick was spot-on when he described to you the differences between our forecast and staff's forecast. But, you know, back at home I have a garden and it's full of rocks, and I guarantee you that any rock I turn over in my garden there's going to be worms, you know. So, I have a few more rocks here that I could turn over to kind of talk about the differences of our forecast.

But these are sizeable rocks, they're not the pebbles.

Starting with peak, I'd like to say, you know, we asked for extra time this year to finish our forecast and submit it. We asked for ten days and you graciously gave us ten days. And we wanted ten days so that we could do a better job in rolling in effects of electric vehicles and private supply and, you know, try to do a better job on those new things that are being introduced to forecasting, now, that haven't been there in years, many years past.

So, we have taken a look, now, at the differences between staff and our forecast and we can, you know, narrow it down to differences in things that we can talk about with staff.

Mainly, if we were to take a look at the peak forecast you'll see that there's 44 -- in year 2024 there's 44 megawatts worth of difference.

But if you kind of turn over the rocks, there's some things that push it up and there's some things that push it down. And these things fall into the categories of electric vehicles having an effect on peak, climate change, private supply, difference in a starting point.

And again, like has been mentioned to everybody, prices. And all of these things are things that we can work with staff on to resolve differences.

A little egg on my face because last year, when it comes to electric vehicles, we were encouraging staff to increase their initial forecast of electric vehicles in our service territory because we truly believed we were getting a larger share of California's electric vehicles.

But now we've got a little bit of historical data to look at and we've taken a little extra time, and we've come up with a new forecast of electric vehicles for our service territory, and staff is still using their old one.

So, I mean right there there's a 40-megawatt difference because staff was assuming more electric vehicles in our service territory than we were.

On the energy side, the same culprits -- oh, I wanted to also mention climate change. We did not add an effect of climate change into our forecast and staff did. I mean there’s 80 megawatts right there.

We just don’t know enough, yet, about the weather in San Diego to be able to forecast into the future a climate change effect. We’re learning, though.

And the DOG Committee is now committed to taking a look at climate change, and we’re hoping that we can anticipate there and learn quite a bit.

So, in the future we hope to make a better assessment of that and maybe bring it in.

Over on the energy side, we were able to take a look at the residential sector and, again, we found the same culprits, private supply, and electric vehicles and so forth. And, again, those are areas that we can discuss with staff and maybe help each other.

There was one area in the energy side of the fence that we still don’t understand. We have differences. And I think Nick pointed it out, too, and that’s the commercial area.

So, we do have differences in commercial area energy and we don’t quite understand what those differences are attributable to, yet, but we're certainly anxious to dig a little deeper and discuss it.

So, that's basically how we differ.

COMMISSION CHAIRPERSON WEISENMILLER: How about on the PV forecast, on the private power forecast?

MR. VONDER: On the PV forecast, again, we asked for extra time so that we could do a better job on the PV forecast, but we ran out of time.

And we used -- basically, we used staff's methodology and some of our own assumptions, and staff's PV forecast came out a little higher than ours, so that would bring their forecast down a little lower.

We want to continue to work on that and try to sharpen it up. I know one thing that we're trying to -- and we weren't able to bring this it at this time, but it doesn't mean that we don't want to.

Now, when a customer makes a decision of whether he wants to install PV at his house or not, he can do the economic analysis with the payback period and all that stuff, but he also has the option, now, of going out and leasing that PV, paying a lease price for a number of years and let the owner of that PV equipment worry about payback and stuff.

And so, that's kind of shedding a different light on how people make decisions as to whether or not they’re going to go with PV. We’re trying to understand that, now, and take a look at that and see if that can be dealt into the methodology for projecting, but we’re not there, yet.

COMMISSIONER MC ALLISTER: I want to follow up on that. Actually, this is a particular area of interest of mine. But I think that there are -- again, you know, this is sort of a pitch that’s having a database that’s fully fleshed out and public so that that analysis can be done transparently, and widely. And not just between, you know, the utilities and the Commission staff, but also avail of industry expertise and have sort of a vetted process to get to those answers.

Because I think this -- these behavioral issues and decision making is really important to understand going forward, both for you as an entity with customers, but also for the Commission and other stakeholders in this space.

So, you know, certainly, one of the issues that I’ve dug into quite a bit is the contractor approach because there’s a wide variety of business models, of offerings on the financing side of approaches to the customer, of sales processes.

And from contractor to contractor, for example, that analysis that you just described varies. Some contractors really do that rigorous analysis and others are really more listening to the customer and selling them what they want.

But the level of proactiveness of the contractor really varies.

All of this is just to say that I think that projection and trying to figure out where the marketplace might be going there is kind of a -- would benefit from a fairly broad and diverse set of skills that is enabled by good information.

And so, I really would, again, encourage the utilities to make sure that the public database does continue to be populated with that kind of information so that we can all have it and avail ourselves of it.

If that's through the interconnection process, or if that's through some other process, or continued administration of some kind of program, you know, CSI version 2 or 3, or whatever, I don't know.

But it would be really good to find out a way to do that because I think it's good for the distributed resources discussion going forward. And increasingly, you know, hopefully, in the energy efficiency discussion going forward that these behavioral issues, and sort of picking apart that marketplace for purposes, not only for EM&V, but for forecasting and a bunch of other things.

So, I do think this -- you know, all of us need good information and a good process to make these decisions and inform them.

So, anyway, I'll get off my hobby horse here. But I do think it's really compelling, super interesting and we all have a stake in it. And so I just want to encourage folks to keep alive as much of this data as possible, but thanks for highlighting that.

MR. VONDER: Well, ditto, ditto.

I guess I would like to make one other plug, and that is for the surveys, the RAS survey, the residential survey, the commercial survey, the industrial surveys, those are really important. And I think, you know, we would be willing to devote an effort into getting that going again. That could produce a lot of very important information. So, I support earlier comments on a desire to go forward on that.

COMMISSIONER MC ALLISTER: Great, thanks.

Let's see, anybody else have any -- do we have any comments here from the dais? No, it looks like not.

So, thank you very much.

MR. WENG-GUTIERREZ: Good afternoon Commissioners, Vice-President Casey. My name is Malachi

Weng-Gutierrez. I work in the Demand Analysis Office with Chris and Nick, and many other people. And I will be going over the POUs, LADWP and SMUD.

I'm going to breeze through LADWP pretty quickly. I think Michael wants to catch an airplane, so I'll try to go through it fairly quickly here.

It's going to be very similar to what Nick had already gone through with the other IOUs, so many of them will look very much the same.

I'll be looking over these four items, planning area results, the efficiency and self-gen, the climate zone results, the two climate zones 12 and 11, and then looking at the forecast comparisons at the end.

So, in general, in the mid case we saw consumption a little bit lower in the current forecast, CED 2013, than we saw in 2011. This is primarily caused by, again, higher rates, everybody's been talking about that, population differences, as well as some of the standards that were included.

LADWP electric consumption grew at a variety of rates, you know, .49 percent, .87 and 1.3 percent across the forecast in the mid, low and high cases, respectively.

In the mid case it reaches a value of 28,000 in 2024.

(WebEx interruption)

MR. WENG-GUTIERREZ: That wasn't me.

Also, in the first year, 2013, obviously it starts a little bit lower than last time, 1.9 percent lower. And that is, again, a result of weather normalization.

Peak rates, again, begin at a much lower rate because of weather normalization, as well, 7.2 percent lower than 2011.

And the mid case grows at about 1 percent, .93 percent through the forecast to a value of 6,124 megawatts in 2024.

As with the previous utilities, the per capita consumption grows pretty significantly through the forecast, at the latter portion of the forecast and that's primarily because of the introduction of electric vehicles and plug-in hybrid electric vehicles. It's one of the largest growing areas in the forecast.

Savings across the forecast, so the savings is relatively narrow, but it does occur in primarily two components, nonresidential price impacts and the residential appliance standards are probably the two largest values increasing over the forecast period. And that does drop off at the end of the forecast, I think partially because of, again, higher rates and potentially what Chris had mentioned in his discussion, the appliance standard -- or the effectiveness decay of the appliance standards, which I think is handled a little differently in the POUs than -- I'm sorry, that's self-gen.

So, the decay rates that Chris had mentioned should apply to here as well.

Okay, so in the self-gen, the energy consumption over the whole forecast period for the mid case is 343 gigawatt hours. And of that 343, 193 gigawatt hours is contributed -- is PVs.

As Asish noted in his presentation, there's a dip in 2016 which is caused by the Federal tax incentives going away. And then the remainder, the rate of growth in the remainder of the self-gen is primarily due to technology costs and the increase in rates.

For the peak self-gen impacts, overall at the end of the forecast, in the mid case there is a peak impact of 56 megawatts, and 40 megawatts of that is attributable to PVs.

For the climate zone results, we're looking at two climate zones, climate zone 11, which represents primarily the Long Beach Region or is represented by the Long Beach Weather Station, and then climate zone 12 which is represented by the Burbank Weather Station.

So, they have, obviously, two different weather stations, as well as different geographic regions.

The climate zone 12 is inland and north, and that's where you see the largest amount of growth.

Across the mid case, for consumption you're seeing about a 1 percent growth in the consumption, as opposed to a .8 percent in climate zone 11.

And then, also in the peak demand you're seeing a significantly higher growth in climate zone 12. Again, this is primarily because of the growth in the Owens Valley area, as well as the differences between the two different weather stations.

So, LADWP submitted a managed forecast and they also then adjusted that managed forecast for us to consider in our comparisons to account for the incremental uncommitted energy efficiency measures. And it was that unmanaged forecast that we used for our comparison purposes.

So, in the unmanaged sales that were provided to us, LADWP's unmanaged sales in 2022 were reported as 26,281 gigawatt hours.

In our preliminary forecast the mid case for us 25,574 gigawatt hours. If we, again, adjust for rates, our forecast comes up to 26,214 gigawatt hours, which is very close to the unmanaged sales number from LADWP.

Again, the rate differences here, we're showing in the mid case about a 45 percent increase in rates from 2012 to 2022, whereas LADWP is using a value a little bit closer to 20 percent.

So, this is just a chart that represents what we just spoke of. The annual rate of growth are all pretty comparable in the adjusted numbers across LADWP's forecast, as well as the preliminary, and then also for the adjusted econometric model results.

LADWP's unmanaged peak forecast in 2022 was 6,545, ours was 6,339 in the preliminary, and then adjusting for the increase in rates, or the rate differences, resulted in ours coming up to 6,450, again closing the gap between the two forecasts.

And this is a representation of that. It looks a little odd only because the first year that we're using to do the comparison is 2013. And in this case it was impacted by the weather normalization, primarily. So, that leads to some percentages that don't quite match with the actual values, which are very close to one another in our -- after adjusting for the rates.

So, that's pretty much what I have for the -- oh, and the only other thing is that there are some inputs that we would like to work with LADWP to explore further. Some of them being primarily dealing with the econometric or the economic components that we've incorporated, and so we'd like to spend some time with them in developing a revised forecast.

And with that I would answer any questions, be willing to answer any questions from the dais.

COMMISSIONER MC ALLISTER: Great, thanks very much. Yeah, it just came to my attention that our representative from LADWP needs to leave quickly. So, maybe before we go to Q&A could LADWP go ahead and respond or provide a perspective, and then we can -- I'm sorry to make you wait around all day and then have to rush right at the end, but sometimes that's the way it goes. And I appreciate you being here and sticking it out.

MR. COCKAYNE: I'm Michael Cockayne. I'm the Supervisor of load forecasting and load profiling at LADWP.

I thank the Commission for holding this workshop. I found this morning very stimulating in the discussion, and a lot of ideas that came about, so really enjoyed it.

Really pleased that given the fact that my forecast is based on a different time period, different revenue classes, different economic inputs, different weather stations and we came out so close together when we did this reconciliation. And I'm certainly willing to work with any economic data that the CEC wishes to discuss and trade information, as we already have started that process in trading information back and forth.

Just to point out, or maybe what makes us, LADWP different, is that Chris mentioned earlier that he thought economics was the main driver in the forecast. I really believe in our service territory that it's the programs that are the incremental difference.

Probably three key reasons, in our industrial sector we have very low vacancy rates in the industrial sector, have no room to grow in the City of Los Angeles for that.

Commercial building is what they call ground filled development, meaning that they have to knock down a building to put up a new building. So, you know, I don't see huge growth in the economics there.

And then, of course, on the residential we're only adding 6,000 units in a normal year to our forecast. So, 6,000 units on a base of 1.2 million really doesn't drive it.

On the other hand, with our energy-efficiency programs we're aiming to hit 10 percent by 2022, so that really -- that, plus the solar rooftop program, to me is the incremental driver in the forecast right now, rather than the -- it’s slightly larger than the economics.

Given, if you set the point that programs are driving this forecast more than economics, then I’m telling my management right now that the forecast will probably be less accurate in the future, than they have been in the past. Our forecasts have been relatively done well.

I guess earlier comment -- or all forecasts are wrong, but some forecasts are useful, I hope that’s what my management feels about my forecast.

And I’m telling them that it may be more inaccurate, and given that it may be more inaccurate, I guess the solution to that is that you have to have more slack in your financial plan, and your IRP, and those type of processes.

So, that’s basically what’s going on at LADWP right now.

COMMISSIONER MC ALLISTER: Yeah, I appreciate that and I was really happy to see the kind of raising of the profile of efficiency programs at DWP with David Jacot coming on, and kind of really an understanding of how important those programs are going forward. So, I think that was a very visible statement that the company made.

MR. COCKAYNE: Yeah, he’s doing an excellent job. I’ve been in meetings with him this year, and also the General Manager, Ron Nichols, has a high emphasis.

COMMISSIONER MC ALLISTER: Yeah, it’s good to see that urgency.

I had a couple of questions here. So, one, what -- so, we’ve talked with the three large investor-owned utilities and clearly the Energy Division of the PUC is -- you know, the rates issue is in the milieu.

I guess I’m wondering what the basis of the rate forecast for DWP is, sort of where that’s coming from, and the origin of any discrepancies between that and the CEC.

MR. COCKAYNE: Well, and in fact I think there will be another rate forecast this summer and we do believe that rates will be increasing.

One, given the energy efficiency we have, our rates are now uncoupled. We get revenue -- we hit our revenue targets through an uncoupled rate process.

And then, also, because of the goal in hitting the 33-percent renewable power standard, and there’s also talk of maybe -- I don’t know if this is official, just talk of the coal -- eliminating the coal fuel in the mix. So, I don’t know if that’s announced yet or --

COMMISSIONER MC ALLISTER: Well, definitely, obviously, we've seen good progress on that. I think Ron Nichols is working hard on divestiture and all that, which is --

MR. COCKAYNE: Right.

COMMISSIONER MC ALLISTER: -- you know, great.

I guess I'm kind of wondering sort of the basis for that assessment. I mean, I'm sure there's a tea leaf, you know, reading the tea leaf aspect here. But to the extent that our staff and DWP can get together and kind of agree on the assumptions for rates going forward, in the same way that we might do it with, you know, Energy Division and the individual utilities in the PUC realm, just some analogous process would be useful, I think.

MR. COCKAYNE: Yeah, in the past, actually, we've only put out a three-year rate forecast and then the rates would go up by inflation, so we would have zero, inflation plus zero, where they were talking about inflation plus one.

COMMISSIONER MC ALLISTER: Okay.

MR. COCKAYNE: Now, since we have all these programs in place, I think there's more willingness to put out a long-term rate forecast.

COMMISSIONER MC ALLISTER: Okay, that's great.

MR. COCKAYNE: So, that's actually a new policy this year. And we'll be able to share that rate forecast with them.

COMMISSIONER MC ALLISTER: Okay, that's great. And then my other question is I'm wondering where the L.A. FIT -- the L.A. feed-in tariff fits into all of this, because it's not traditional self-gen in that it's not behind the meter, but it does affect the peak, and it is a program with some -- I mean it's a DG-related program. So, I'm kind of wondering how that fits into both the Commission work and to DWP's work.

MR. COCKAYNE: Well, in my forecast -- I don't know how it works in the Commission.

COMMISSIONER MC ALLISTER: Okay.

MR. COCKAYNE: But the feed-in tariff is not in my forecast.

COMMISSIONER MC ALLISTER: Okay.

MR. COCKAYNE: And we handle the feed-in tariff in our IRP plans.

COMMISSIONER MC ALLISTER: Right, so I mean it is procurement, so it's not technically, you know, demand.

MR. COCKAYNE: Right.

COMMISSIONER MC ALLISTER: But it does impact the peak. So, you know, peak shifting will happen in some ways because of it.

MR. COCKAYNE: Right.

COMMISSIONER MC ALLISTER: So, I guess I'm just kind of wondering -- so, really, I guess you're saying that's a separate topic entirely.

MR. COCKAYNE: Right.

COMMISSIONER MC ALLISTER: Okay, great.

MR. COCKAYNE: Or at least I'm not handling it in my forecast right now.

COMMISSIONER MC ALLISTER: Okay, great. Keith?

MR. CASEY: Just a quick question on the staff's presentation on the PV build out, I noticed a pretty modest build out over the next decade of incremental, 40 megawatts in terms of peak impacts. And I was just wondering if you could shed any light on --

MR. COCKAYNE: I have a number off the top of my and I thought it was higher. Now, one -- I think we have a program to hit 350 megawatts PV by 2030. But our PV peaks, production peaks 12:00 to 1:00, our system peaks 1600 hours. So, I think there's a 40 percent decline from the peak production to our system peak.

MR. CASEY: That's interesting, because looking at the San Diego numbers, they were looking at, basically, a hundred percent increase in PV build out over that same period. But, of course, they have more inland areas than you do and maybe that makes a difference on the peak and --

MR. COCKAYNE: Well, the other thing I think that makes it more difficult in our service territory is that the majority of our householders are renters. And right now we're building apartments, not single-family housing. So, we really have -- we don't have that new, single-family house, which to me is the obvious target market for PV and the zero net energy. And I think the apartment issue is more difficult, so benefits from that.

COMMISSIONER MC ALLISTER: Just following up on that, aren't there some differences between DWP and some of the other utilities, including the IOUs, on what's sort of permissible with respect to rooftop solar, and ownership of rooftop solar? I mean there's some additional constraints, I understand it.

I'm not totally up to date on this so I guess I'm asking is there --

MR. COCKAYNE: I'm not an expert on regulations on the PV.

COMMISSIONER MC ALLISTER: Well, I'm just thinking the sort of third-party ownership of rooftop solar, I've understood, is not easy to do in DWP territory. Whereas, so the PPA model that's sort of taken the rest -- taken the IOU service territories is less possible over there, but I could be totally wrong about that, at this point I'm not sure.

MR. COCKAYNE: Historically, the district, the City of Los Angeles attorneys have been against ownership of generation within our service territory.

COMMISSIONER MC ALLISTER: Okay.

MR. COCKAYNE: So, that may be where you're hearing that.

COMMISSIONER MC ALLISTER: Right. So, yeah, so there's something about the application of that metering limits some of the options for rooftop solar.

MR. COCKAYNE: Right.

COMMISSIONER MC ALLISTER: So, that could explain some of that discrepancy, too.

Which is why I'm asking about the FIT because I think it's got a lot of -- it fits the model in a way that I think could have some serious traction and looks like it's going to be a good model for the rest of the State in some ways. And so I'm kind of excited to see that go, even if it's not exactly part of this discussion, necessarily.

So, I really -- I don't have any other questions. Okay, great. Perfect. So, you're only a couple of minutes past 4:30 so, hopefully, you can catch your plane. Thanks very much.

Great, so I wonder if staff, based on the little back and forth just now, is there any clarification that might have popped -- any of those questions -- I guess I was also wondering about sort of the PV issue with respect to staff. Let’s see, I guess I was wondering about the L.A. FIT, but it sounds like that’s probably not in staff modeling at all, either.

MR. WENG-GUTIERREZ: Yeah, I’m not -- I don’t think so, no.

COMMISSIONER MC ALLISTER: Great. Great, okay, that makes sense.

MR. WENG-GUTIERREZ: All right. Now, I might take a minute or two longer to go through this, although it is a shorter section because it doesn’t have multiple climate zones. So, perhaps it will be about the same length, but I won’t speak as quickly.

So, in general I’m going to be going over the planning area results, the efficiency and then self-generation components and then do, again, a forecast comparison with the SMUD forecast that was submitted to us.

As an overview, in the mid case in 2022 our current CED 2011 forecast is 3.3 percent lower. Partially, this is influenced by near term -- lower values in the near term because of economic growth assumptions, as well as the higher rate -- the higher rates that are assumed in all the cases.

And for SMUD's electricity consumption, the mid case grows at just over 1 percent, 1.08 percent to 12,071 gigawatt hours by 2024.

In 2013, the value that we are using as the starting point for the forecast is 2.8 percent lower than in the CED 2011.

Similarly, the near term or 2013 starting point is significantly lower than the CED 2011 value. Whereas the growth rates in the low and the mid case are comparable to what we're seeing in the previous mid-level forecast, just over 1 percent, 1.12 percent.

And the mid case grows to approximately 3,500 megawatts in the mid case.

Per capita consumption is lower in this case than the last forecast and in due, partly, because of the assumptions in the beginning of the forecast.

The trends are somewhat similar, but grow a little bit quicker throughout the forecast partially because of the EV adoption through the forecast.

And, similarly, the savings across the forecast period is just over 2,200 gigawatt hours. And again, in the latter portion of the forecast we see impacts of price rate changes, as well as, I think, appliance standard decays.

And as with the LADWP, and other utilities, the self-gen -- the shape of the self-gen shows the end of the Federal tax incentive in 2016, and then a longer-term growth rate which is correlated with technology declining costs, as well as increasing rates, and continuation of housing starts through the forecast period.

Likewise, the peak impacts show a similar trend, the ending of the Federal tax in 2016 significantly changes the rate of growth of self-gen.

And for SMUD’s territory, most of the self-gen impact is associated with PVs. I think in the mid case for peak the total at the end of the forecast is 32 megawatts, of which 31 megawatts is attributable to the PVs.

And then for our forecast comparison with SMUD, we had three submitted to us, an unmitigated case, an unmanaged case and a managed case.

The unmitigated case doesn’t change any changes across for energy use behaviors, and stock changes or efficiencies in the forecast period.

The unmanaged case does include some end-use appliance saturation and efficiency changes to new home constructions during the forecast period.

And then the managed case obviously includes many other program impacts going forward.

So, in looking at what was included in each of those three cases we decided that the unmitigated forecast, as it was defined, or was it was provided was most comparable to our forecast, since there are no new efficiency impacts recorded during the forecast period.

So, SMUD’s unmitigated sales forecast in 2024 was 12,359 gigawatts, ours was 11,832, so slightly lower.

If we adjust, again, for rate differences, ours is raised to 12,423 and, again, very close to what they had in their case. So, we felt like it was a pretty good estimate just considering the differences in the rates, and beyond that we’re pretty close.

And this just shows, again, the annual average sales growth across the forecast period starting in 2013, so it does lead to a little bit of difference between of the -- the difference between the SMUD’s forecast and ours in 2013 does show -- does cause a little bit of variation in the annual growth rates. But for the most part we end up very close to one another at the end of the forecast, adjusting for rate differences.

And then for SMUD’s peak forecast we, again, used a comparison of the unmitigated peak forecast to ours. Their value in 2024 is 3,426 megawatts, ours is 3,490 megawatts. Adjusting for rates, our 2024 number becomes 3,612.

So, I think in this case we are including a bit of -- a bit more economic growth than they might be including. And then we also have a starting point which is a little different than theirs, so that causes a little bit of difference here. And again, that difference, both in the starting point, as well as some of the factors contributing to the change over the forecast does lead to a slight difference here. But for the most part we feel that we're pretty close to what they've produced in their -- submitted in their unmitigated case.

And with that I'd be happy to answer any questions.

MR. CASEY: I guess I had just a similar question on -- I'm just, particularly for SMUD, struck by the relatively low impact of PV, both in peak demand and overall energy consumption. From an energy consumption stand point, in 2024 it's about two percent of their total and it's just kind of surprising for an inland area.

MR. WENG-GUTIERREZ: I don't know that I can speak to why that would be such a -- it is the largest component of self-gen, you k now.

MR. KAVALEC: So, it's basically the incentives, the CSI program versus what the publicly-owned utilities offer in terms of incentives that's creating the difference in growth.

COMMISSIONER MC ALLISTER: And Chris, those incentives would include, I would imagine, not only the -- you know, the CSI or, you know, equivalent solar incentives, but also the kind of rate structure -- incentives built into the rate structure as net metering, and that kind of thing as well, right?

MR. KAVALEC: That's right.

COMMISSIONER MC ALLISTER: I guess, if the SMUD rep is here, then maybe we can talk about those rate issues.

COMMISSION CHAIRPERSON WEISENMILLER: Well, certainly, SMUD has a significant fixed charge, where the IOUs don't.

COMMISSIONER MC ALLISTER: Well, and the tiers are less aggressive, so the sort of lopping-off-the-top-tier strategy isn't quite as compelling.

Do we have a rep from SMUD here?

MR. WENG-GUTIERREZ: Yes.

COMMISSIONER MC ALLISTER: Yes. Okay, great. Yeah, so great, thanks Malachi, very much.

COMMISSION CHAIRPERSON WEISENMILLER: Thank you.

COMMISSIONER MC ALLISTER: We'd like to invite SMUD up. Oh, here we go.

MR. TOYAMA: Nate Toyama from SMUD. Here's my information, if you need it.

The first slide, just an overview of what I would like to speak to the audience and Commissioners about is basically reviewing our forecast, just like Mr. Gutierrez did.

But, really go more beyond that and talk about our unmanaged and managed forecasts. These are the forecasts that we use for our planning purposes and for both sales and peak. And then examine a bit of our program impact, which seems to be the difference between our forecasts.

And so, this was what was referenced in the discussion on SMUD. As you can see from this graph on the sales, we're roughly about the same. And so, if we looked at our unmitigated forecast and the CEC's no-rate-adjustment forecast, for lack of a better word, we're pretty close.

The difference really becomes apparent when we talk about our -- the next forecast, which was in the slide, the CEC folder 1.1.b mid case. We have a bit of a difference there in terms of our unmanaged and our forecast.

But in our unmanaged forecast it’s really sort of a bench mark, is it’s this forecast that we’re going to use to describe how we plan to achieve our other goals, such as our EV goals, our PV goals, EV and some other sales goals that we have, which is the next slide.

And on this slide we have the same forecast that we had in the previous slide, but I want to bring your attention to the red line, which is the managed load, and the managed load is the one that we use for forecasting purposes.

And in the footnote below we have our managed forecast, which includes our own EV program -- I mean, excuse me, our EE program, our PV program under SB-1, EV, which will lift it back up. And we had some departing load last year, so we have it in our forecast.

But this is where the substantial differences are.

And in terms of our planning process, the red line is what we use for our procurement, our planning purposes, our risk management, and it does -- at least in the first year it’s not that far apart, but in the year 2024 it is quite different.

COMMISSIONER MC ALLISTER: I guess I’m -- so, the impact -- like price effects, generally, are those in there anywhere? I mean what's the --

MR. TOYAMA: We don't have any price effects in our model, per se.

COMMISSIONER MC ALLISTER: Okay.

MR. TOYAMA: At least not in terms of elasticities.

COMMISSIONER MC ALLISTER: Okay. It's kind of notable that with incorporating the increase --

MR. TOYAMA: The difference is really our program impacts.

COMMISSIONER MC ALLISTER: Well, I guess I'm just noticing that incorporating rate increases and not -- you don't incorporate rate increases and the CEC kind of does, and builds that in, but you're still pretty close in these forecasts.

MR. TOYAMA: We don't have elasticities, we don't have price elasticities or income elasticities.

COMMISSIONER MC ALLISTER: Okay, so yours is kind of a more mechanistic model.

MR. TOYAMA: Yes.

COMMISSIONER MC ALLISTER: Okay.

MR. TOYAMA: And partly because we -- you know, at the SMUD level we just haven't seen it in terms of -- not seen it. We just haven't been able to estimate it with any confidence.

COMMISSIONER MC ALLISTER: Okay.

MR. TOYAMA: So, both the price part and the income elasticity. And so, because of the uncertainty of the numbers, we don’t use it.

But the other question might be is how does the price impact really sort of -- what is the mechanism of a price impact? What do people do when prices change?

If they resolve -- in the long term we believe that perhaps price changes, as well as income changes may affect your portfolio selection.

And in our models we do have a portfolio or we have a saturation model which examines different saturations in appliances, and we cover the main appliances. For residential, at least, we’ll cover TVs, we cover refrigerators, HVACs, cooking. We have about ten major appliances that we model with both saturations and level of efficiencies, and that’s -- and that’s covered, basically, in our unmanaged forecast.

COMMISSIONER MC ALLISTER: So, I guess with the investor-owned utilities and with the CEC -- well, really, I guess with the CEC approach, you know, there’s some categories of savings. You know, there’s standards, and programs, and price effects. And then also, you know, there’s some consideration of naturally occurring savings.

So, I guess could you sort of break up -- I mean, this seems simpler. In a lot of ways it allows you to sort of -- you know, the attribution question gets simpler under your approach, which is great. I guess I'm kind of wondering --

MR. TOYAMA: At the end of the -- in a couple of other slides I'll show you what it goes into.

COMMISSIONER MC ALLISTER: Okay, great, great. I'm sorry to beg all your questions there.

COMMISSION CHAIRPERSON WEISENMILLER: Well, I just had a quick question. What's the pending rate increase SMUD is looking for over the next year?

MR. TOYAMA: I'm sorry, what was that, again?

COMMISSION CHAIRPERSON WEISENMILLER: My impression was that SMUD has just launched an effort and I think it actually started this week, of workshops concerning a potential rate increase for this year.

MR. TOYAMA: The proposal in SMUD's General Manager's report, which was released a couple of weeks ago, has a proposal for a 2.5 percent increase in 2014, and another one in 2015.

In 2013, as well as 2012 there was some realignment of the rates, primarily affecting residential customers. Where the major impact was to increase the customer charge, but the overall revenue requirement stayed the same.

So, these are the -- for 2014 and 2015 the price proposals are 5 percent over a two-year period, and that’s the proposal that’s made to the board. I believe there’s probably another 60 days in which the board will make that decision.

But if you had -- well, if we had to look at real prices, I’m not clear that we would have -- I don’t know, I haven’t looked at it in a while, but if we had looked at real prices I don’t know if it would -- if our SMUD rates have been actually increasing over time. Probably in the long run they’ve been either zero or negative since the 1990s.

COMMISSION CHAIRPERSON WEISENMILLER: No, my impression is that SMUD has generally tried to squeeze savings out instead of increasing rates in recent years. So, this is the first proposed rate case -- rate increase we’ve seen in a while.

MR. TOYAMA: What was that question or was that a comment?

COMMISSION CHAIRPERSON WEISENMILLER: More a comment. I just said that was my impression, also, that your rates have been pretty flat.

MR. TOYAMA: All right. And so, basically, to summarize, these are differences, is that the differences are very minor other than for the programs that SMUD has been trying to accomplish.

The next slide -- oh, wrong button. The next slide is the peak forecast and this is where we have some differences. But overall the differences, when you talk about megawatts and how we might mitigate those differences or mitigate the risks of those differences, they really tend to be quite minor.

I think, although the CEC has been comparing the unmitigated with the CEC-adjusted, I really think that the SMUD unmitigated and the mid case, which is the red line, are more appropriate to evaluate as a comparison. And I think that when we look at these differences, the differences are, once again, very, very minor.

On the other hand, it's not what we use for planning purposes. And so we go to the next slide -- well, this is a talking point.

One talking point I wanted to make, because it varies quite a bit from ours, is really the bump in the peak usage in 2013. That seems to be a little bit higher than ours, so I brought a slide which shows you our peak usage on a per-account basis, which is this one.

And what I have is the historical peaks on a per-account basis. The red line is the temperature for that peak day and then I have the three scenarios are unmanaged, or are unmanaged and managed, and then the CEC's forecast.

And as you can see, the CEC's forecast is just a bit higher than ours. Now, that's not to say we wouldn't achieve that type of peak demand under certain conditions, but I think those certain conditions would be a bit above what we normally consider our normal peak, or our normal temperature conditions for our peak.

COMMISSIONER MC ALLISTER: So, could you go back to the previous slide?

So, you're talking about the gap in 2013, '14, '15, rather.

MR. TOYAMA: Yeah, I'm talking about the gap in the first couple of years of the forecast.

COMMISSIONER MC ALLISTER: Yeah, okay.

MR. TOYAMA: So, '13 and '14.

COMMISSIONER MC ALLISTER: Okay, so you're saying basically that it's due to weather effects or some assumptions UNDER weather?

MR. TOYAMA: It could be it's just differences in approach, but it seems to be a bit above what we are -- well, it seems to be a little bit high than what we observed in the last couple of years.

And so, we still think that we're -- and I would attribute this to our somewhat of a recessionary period, and we don't think we're going to recover that quickly out of the recessionary period.

We still think that 2013 is still going to be a slow growth. We're starting to see that we're having a pickup in residential customers, but it's still well below what we've seen in the last ten years. We're looking at maybe two to three thousand in customer growth this year. In the past we've had maybe 2,000 customers. Well below what we've seen in the past, which has averaged anywhere from 10 15 thousand customers.

But I think the main thing is the recessionary period. And the peak growth, what we attribute the more recessionary period is more to the commercial class. We've seen a quite a bit of reduction in usage and peak demand by our commercial customers.

And if anything goes like it has been in the past, the commercial class will recover, but it tends to lag behind residential customer growth. And so that was one point that could be a major difference.

Now, if we were to make slight adjustments, then our peak forecast would almost be identical.

COMMISSIONER MC ALLISTER: Okay, great.

MR. TOYAMA: I'll bring that slide back. If we were to make the adjustments in ’13 and ’14, you see that the blue bars and the black lines would almost have the same slope, roughly about 1.3 percent. The difference is really that little bump there.

Let’s see, where am I? Okay, this is really our managed and unmanaged forecast. Again, the differences are really our programs that we have. So, it does look to be quite a bit of a difference, maybe three to four hundred megawatts. Yeah, about three to four hundred megawatts, which by 2024 is quite substantial.

COMMISSIONER MC ALLISTER: So, just to be clear, the one that you use here is the managed, right? So, for your long-term planning purposes, for going out and doing procurement and all that, you’re using the red line here?

MR. TOYAMA: That’s correct.

COMMISSIONER MC ALLISTER: Okay.

MR. TOYAMA: And it’s really the difference between the red line and the blue line, you know, we’re looking at another resource.

So, I mean when we file our reports to both the WCC and the FERC we always include the blue line forecast, but the difference between the blue line and the red line is essentially energy efficiency.

And so, we include it in a resource in those proceedings and -- and so, anyway, let’s go on to the next slide where we’ll actually see.

This is how I -- what I did is I looked at all the different programs that we have and how we account for changes in load growth, and sales growth. And what these give you are is an idea of the magnitude of the differences from our unmitigated forecast down to our managed forecast, in terms of percentage.

And so, we can see by 2024 that our program will result in about a 12 percent reduction in the usage relative to the unmitigated forecast for sales.

For peak it’s slightly lower because a lot of the programs we have don’t affect peak in the same percentage, it’s slightly less.

And so we see that by 2024, in our peak forecast our programs and the evolution of the housing market, and construction standards will result only in an 8.4 percent reduction from our unmitigated forecast.

And I think a lot of it is how we account for these difference in program, SMUD’s program, as well as what may occur in the market, itself.

The next slide are the numbers. The first slides are percentages, the second slide are numbers. Except I think I put the wrong slide up when I made it, so I don’t have the unmitigated, I just have a relationship between our unmanaged and our managed forecast.

Part of the -- I guess part of the fun of making a forecast is associating uncertainty to various things. And we have fairly good certainty that we’re going to have that level of EE which, roughly on an annual basis, is 1.5 percent of sales.

We have our SB-1 or our PV program that we’re pretty sure we’re going to meet our goals, or we’re certainly going to try to meet our goals.

The real uncertainty in this particular forecast is EV. It’s a very -- we just don’t know.

The next slide I have shows you our EV forecast, and this is our plug-in electric vehicle forecast. For 2013 we’re assuming we’re going to have -- reach about 450 cars. This is a combination of battery and hybrid battery cars.

The next slide is what we’ve just pulled off the internet and what we used a lot for our planning purposes, is actually the history of EVs in SMUD’s territory based on -- I believe they’re based on the rebates. And you can -- the top -- the internet site is where I downloaded this data. Actually, I just copied the data.

But what this website does, it tells you the cars that have received rebates. It's done by service territory for all the utilities. I believe it's also done by counties. It breaks it up into the ZEV, which is our battery cars, and our PHEVs, which are plug-in hybrids.

If we look at 2013, these bars roughly add up, from January to May, about 150 cars, about 100 of them being plug-in electric vehicles, with the other 50 being plug-in hybrid vehicles. Which is we think by the end of the year will be fairly close to our forecast.

Now, the difficulty of the EV part is, of course, what's going to happen in the future. And so as we see, just basically this chart shows that the number of vehicles will go, basically escalating, you know, at an exponential rate.

COMMISSIONER MC ALLISTER: Could you remind us how many -- how many accounts do you have at SMUD? I should know this, but how many customer accounts do you have at SMUD?

MR. TOYAMA: Residential, we have approximately 540,000. Commercial customers, we have about 70,000. Of the 70,000, 50,000 are very small -- or 60,000 are small. That is they're under 20 kilowatts.

COMMISSIONER MC ALLISTER: Okay, so you're saying one in --

MR. TOYAMA: So they're large, but in small numbers.

COMMISSIONER MC ALLISTER: So, by 2030 or so you're one in three -- one in three or one in four of your customers has an EV by 2030 or so, one in four, probably, by that time.

MR. TOYAMA: Yeah, I think that's probably a rough average.

Anyway, that's the end of my presentation, if you have any questions.

COMMISSIONER MC ALLISTER: Thanks for taking our interruptions along the way, I think we've gotten -- Keith, unless you have something? Okay, I think we're good. Thank you very much, that was helpful.

MR. TOYAMA: Thanks.

MS. KOROSEC: All right, we've come to that long-awaited moment for public comment, for all of those who were bold enough to hang in there, either here in the room or online. So, we'll first take comments from anybody in the room who's interested in making any final statements or any final questions.

Okay, I think we about killed everybody.

We don't have any WebEx questions, but we do want to open the two phone lines to make sure that our phone-only people have an opportunity to make a comment, if they so choose.

All right, the phone lines are open. Does anyone have any comments or questions?

All right, I think that does it for us. I just want to remind folks about when public comments are due.

There we go, next steps. So, public comments are due on June 10th and these are the instructions for submitting them.

Thank you very much, everyone, for your fortitude and hanging in there for the whole day.

Would you like to make any closing remarks, Commissioners?

COMMISSIONER MC ALLISTER: Just briefly, thanks to everybody for coming. I really enjoyed the discussion. I think it was terrific to have the CAISO and the PUC represented here today. I think we had a really robust interaction. Certainly, we're all interested in this for similar reasons. And I think we're really committed to hammering out differences and making sure that we're as transparent as we can be going forward.

And, you know, I think just as we've -- as we've faced the various imperatives to collaborate and coordinate across agencies, I think it's really imbued this forecasting process, sort of put it at the next level of importance. It's really kind of jacked up the importance of it. And so, I'm really kind of happy to see the participation and interaction meeting that need.

And so, I'm very hopeful about not only this year, but subsequent years, and really having a good platform to keep building on.

So, I don't know if Chair Weisenmiller has other things to say.

COMMISSION CHAIRPERSON WEISENMILLER: Yeah. No, again, I'd certainly like to thank everyone who's hung in here and appreciate the participation of our sister agencies here, and that Keith, and Commissioners Florio and Ferron invested the day here with us.

I think, certainly, you know, in my own mind it's certainly good to look at the rates issues. And I think, also, in terms of it's good to sort of between the Energy Commission, and the utilities, and also the ISO to make sure we're lined up on the weather normalization stuff.

And again, just sort of continue to work forward on getting to some common platforms on these issues.

COMMISSIONER MC ALLISTER: Keith?

MR. CASEY: Well, I just want to thank Commissioner McAllister and Chair Weisenmiller for inviting the ISO here. I really enjoyed the discussion today and learned a lot. And I was also really impressed with the CEC staff, and the utilities who presented as well, it's clear there's a huge amount of work and expertise that goes into this. And just the level of sophistication in thinking about these things and explaining them was quite impressive, so really enjoyed the day.

COMMISSIONER MC ALLISTER: Yeah, and I'll echo that. Thanks to Chris, and the team, and Nick, and Malachi, I think -- and, obviously, the IEPR team, Suzanne and Lynette.

Really, this is just a fantastic demonstration of our expertise and our abilities in this area. I really appreciate your rousing to the occasion and making it all happen, so thanks very much.

And I think we're adjourned.

(Thereupon, the Workshop was adjourned at 5:05 p.m.)

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