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STATE of CALIFORNIA

CALIFORNIA ENERGY COMMISSION

STAFF WORKSHOP

In the Matter of:	Docket No. 21-IEPR-05
2021 Integrated Energy Policy Report (2021 IEPR)	
	Re: Natural Gas Market and Demand Forecasts

IEPR COMMISSIONER WORKSHOP
ON NATURAL GAS MARKET AND DEMAND FORECASTS

REMOTE-ACCESS ONLY

MONDAY, AUGUST 30, 2021

1:00 P.M.

Reported by: Elise Hicks

APPEARANCES

COMMISSIONERS PRESENT:

Commissioner J. Andrew McAllister, California Energy Commission (CEC)
Commissioner Siva Gunda
Commissioner Karen Douglas
Commissioner Patty Monahan
Commissioner Houck, CPUC Commissioner

CEC STAFF PRESENT:

Heather Raitt, CEC

GAS FORECASTS AND LONG-TERM PLANNING OVERVIEW

Melissa Jones, Senior Energy Policy Specialist, CEC

NATURAL GAS MARKET PRESENTATIONS

Anthony Dixon, Lead Natural Gas Market Modeler, CEC
Ryan Ong, Natural Gas Market Modeler, CEC

UTILITY GAS DEMAND FORECAST/METHODOLOGIES PRESENTATIONS

Andrew Klingler, Senior Manager of Rate Architecture and Load Forecast, PG&E
Todd Peterson, Principal, Energy Analysis and Insights, PG&E
Kurtis Kolnowski, Expert, Energy Analysis and Insights, PG&E
Amy Kouch, Analyst, Resource Forecasting, PG&E
Sharim Chaudhury, Manager, Cost Allocation and Rate Design, SoCalGas
Jeff Huang, Senior Resource Planner, SoCalGas

PUBLIC COMMENT

Mike Florio

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P R O C E E D I N G S

August 30, 2021 1:01 P.M.

MS. RAITT: All right. Well, good afternoon, everybody. Welcome to today's IEPR 2021 Commissioner Workshop on Natural Gas Market and Demand Forecasts. I'm Heather Raitt, the Program Manager for Integrated Energy Policy Reports.

This workshop is being held remotely consistent with the Directive Order N08-21 to continue to help California respond to, recover from, and mitigate the impacts of the COVID-19 pandemic. The public can participate in the workshop consistent with the direction in the Executive Order. To follow along, the schedule and slide decks have been docketed and are posted on the CEC's website. Just go to the 2020 -- 2021 IEPR webpage to find them.

All IEPR workshops are recorded and recording will be linked to the Energy Commission's website shortly following the workshop and a written transcript will be available in about a month.

Attendees have an opportunity to participate today in a few different ways. For those joining through the Zoom online platform, the Q&A feature is available for you to submit questions. You may also upvote a question submitted by someone else. Just click on the thumbs up icon to upvote.

Questions with the most upvote are moved to the top of the queue.

There will be a few minutes near the end of the panel to take questions, but likely will not have time to direct all of the questions submitted. Alternatively, attendees may make comments during the public comment period at the end of the session. Written comments are also welcome and instructions for doing so are in the workshop notice. Written comments are due September 13.

And with that, I turn over to Commissioner Andrew McAllister, the lead for 2021 IEPR.

Thank you.

COMMISSIONER MCALLISTER: Thank you, Heather.

Want to just again thank you. We had just a series of very substantive workshops, rapid succession over the last couple of weeks and I just want to express appreciation to you and your staff for just keeping lots of plates spinning and doing such an amazing job keeping the trains running down the tracks because there are lots of them right now.

And no more important than this topic which is part of our forecasting track and Commissioner Gunda leads this effort. So I will only speak briefly here and leave the lion share of the time for opening comments to him. But just, you know, I have overseen this in the past, the forecasting, and worked with Mr. Gunda on this for a number of years now. And it is really just -- and before that with Chair Weisenmiller. And it's just the bread and butter of the Commission. It's one of the reasons the Commission was formed and it is no -- in all the history of the Energy Commission, I think probably we're at a point where the forecasts are both more important than they've even been and more intertwined between electric and gas than they've ever been.

And this is a function of the time we're living in and the goals that we have. And really making sure that we're, I think, being situationally aware and that we're really looking at these issues from all the analytical perspectives that might apply and with historical perspective and with the sort of real time learning that we're doing as a state. And certainly trying to respond to the imperative of reliability and health and safety and equity and just any number, and decarbonization obviously.

So with so many -- not competing, so many complementary goals here. We have to get them all right. So the stakes are high on this and I know that we have a really robust staff and very deep bench, really quality professionals, the best there are, doing those analyses and collecting all the information they need to underpin it. So I'm just glad to be here today doing this and taking sort of the next step in the gas demand forecasts.

So I would like to just wrap it up there and express my appreciation to all the staff that's been working on this, and EID and then the IEPR team.

So over to you, Commissioner Gunda.

COMMISSIONER GUNDA: Thank you, Commissioner McAllister. I mean, I would yield all my time to you, as you know. You set the stage always so thoughtfully and then the experience that you carry in these areas. Again, I always like to say this, know it's a pleasure to share the dais with you now, this has been my mentor for several years, and now as a colleague.

So with that, I really want to start with thanking Heather and her incredible IEPR team. As usual, I'm really looking forward to the meeting today, to the workshop today.

In interest of time, given that we have, you know, some of the panelists need -- have tight deadlines here, are hard stops. I do want to keep my comments brief. Just want to invoke one specific thing that Commissioner McAllister just mentioned which is that forecasting is a core responsibility of the Energy Commission. And, you know, for the last several years, we spend a lot more time as a Commission going through the vetting of our electricity demand forecasts given its importance in the IEPR, transmission funding, and such. And for a long time, the natural gas forecasts has been on kind of an equal of being kind of a study -- study state.

But given the importance of the rapid climate goals that we have in terms of electrification, it is important to update and objectives analysis out there that provides, you know, the forecast for natural gas. That could be another data point as the industry double up their own forecast. So I'm incredibly thankful for our natural gas team to reinvigorating the process of the natural gas forecast, both in the short term but also the broader long-term planning scenarios. So it really helps the state with some critical policy decisions and similar to how we do it on the Energy Electricity Demand Forecast, I hope will create a robust stakeholder process where we collectively generate a demand forecast that we all feel comfortable as we pursue the long-term transition to a carbon neutrality and a zero carbon California that is clean and reliable and affordable.

So with that, I am, you know, incredibly proud of the work that our gas team is doing, Melissa Jones, Jennifer Compagna, and A.J., Jason, everybody who's going to speak today. Thank you all for your incredible work.

With that, I'll pass it on to Heather to commence the very first presentation here unless we have any other commissioners.

MS. RAITT: I don't think we've had any commissioners join yet, but. So thank you, Commissioner.

This is Heather. I'll go ahead and get it started.

So our first presentation is from Melissa Jones, who is the Senior Energy Policy Specialist in the Energy Commission's Assessment Division. And she's going to give us an overview of the day.

So thank you, Melissa. Go ahead.

MS. JONES: Thanks. Good afternoon, everyone. I am Melissa Jones and I am first been a principal for both electricity and natural gas issues with the Energy Commission's Assessment Division.

The goal of today's workshop in the scoping order for the 2021 IEPR, we identified the two primary issues for the gas track. The situational awareness as a merging topic for natural gas system planning. And then refinement and development of critical analytical product that will be necessary for gas planning in the state.

Today's workshop is going to focus on gas market and demand forecast topics. I will present an overview of historic gas prices, rates, demands, and talk about forecast improvements that we're planning to make. Anthony Dixon, AJ, will be providing an overview of our natural gas price and rates forecast. And Ryan Ong, who is our newest member, will be talking about the burner tip price forecast and electric generation in the west. And then to cap off the afternoon, the two gas utilities will be presenting their gas demand forecasts and we're looking forward to that.

I should also mention that the -- that we've had a number of workshops on natural gas. We have three more topics that are going to be viewed in workshop. Tomorrow we're having a workshop on renewable natural gas, and then later in the process, December timeframe, we will be talking about long-term demand scenarios and the gas demand forecast.

So the CEC presents forecasts. We do forecasting assessments under the Warren Alquist Act which directs us to forecast natural gas demands, supply, transportation, price, rates, reliability, and efficiency. And we do this to identify impacts on public health and safety, the economy, energy diversity, resources, and the environment. And the other thing the Energy Commission is charged with is to identify emerging trends and impending or potential problems or uncertainties in the electricity and natural gas markets and in the industry as well.

Next slide, please.

So the Energy Commission's forecast is used -- our numerous forecasts are used in a number of different areas. The forecasts feed into the California Energy Demand Forecast, our natural gas price fits into that. Our natural gas prices and demand also are inputs into the CEC's PLEXOS modeling for production cost modeling of the electricity system. The CPUC uses price -- our prices in integrated resource planning. The CAISO uses some of forecast in transmission planning. WECC uses some of our forecast in production cost modeling and in their policy and planning. The Northwest Power and Conservation Council uses our forecasting in policy and planning. And then the California Gas Report, some of the utilities use our price forecasts as an input to their forecasting activity.

Next slide, please.

This year we have focused on a number of improvements in the gas forecasts. This is to follow up on recommendations made in the 2019 IEPR for us to expand our analytical capabilities. The CEC develops its commodity price, gas price, using a North American Gas Market model called NAMGas which captures the entire North American gas market which is a continent-wide market. The CEC made a major effort this time to expand the model from an annual model to a monthly forecast. This allows us to better capture seasonality and demand changes.

The CEC is using a new model that was developed by Aspen. Katie Elder developed a model to forecast rates so we can better incorporate revenue requirements and other factors in our rate forecasts.

We've also made a number of improvements to the Burner Tip Price forecast. And the Burner Tip Price is the price that is used in PLEXOS as a proxy for natural gas costs or natural gas prices. We developed a model that better reflects price formation in the gas market. We realigned the transportation rate from what used to be called proxy hubs which were places that were near where power plants were located. But they weren't actual market hubs, meaning that they weren't liquid training points so we've reoriented that model to now reflect actual market hubs.

And then we have gone through a process of identifying improvements that will be needed to gas demand forecasts to facilitate long-term planning. I'll also be talking about that.

I should say that in the IEPR, electricity issues are usually front and center. We're trying to put more emphasis on natural gas and so part of what we're doing in these overview presentations is trying to familiarize people with natural gas issues, those who aren't familiar with it.

Next slide, please.

So in terms of gas supply trends, California gets about 90 percent of its gas from out of state from supplies that is 1,000 miles or more away from the state. Of that 90 percent, about 20 percent of it comes from Alberta, Canada and it comes into California via Gas Transmission Northwest pipeline. We get about 30 percent of our supplies from southern Wyoming via the Ruby pipeline and the Kern River pipeline. We get 40 percent of our gas from the San Juan Basin, that's the northwest New Mexico area and that is transported via El Paso Natural Gas and Transwestern pipeline. And then we get about 10 percent from the Permian Basin which is both west Texas and southeast New Mexico areas. And that also comes in via El Paso and Transwestern pipeline. The other 10 percent of our supplies comes from in-state production and that production has been slowly declining since the 1980s and it's anticipated to continue to decline.

Next slide, please.

Oh, I should say one more thing. So PG&E generally is more reliant on Canadian gas and SoCalGas relies more on Rockies and San Juan gas.

Next slide, please. Gas prices.

So this graph shows volume weight rated Citygate prices, average annual prices. And what you can see from this is that California's prices have tracked of the U.S. and it's actually been lower except during the 2001 -- 2000-2001 energy crisis. They're fairly close to the U.S. I think there's an impression that California pays more for gas but this is the situation. And what you can see here is that since -- from the 1980s to about 2000, we had low fairly stable gas prices in the state.

Starting in 2000 with the energy crisis, we had a big peak in gas prices. FERC [Federal Energy Regulatory Commission] investigated the market at that time and discovered that there had been widespread market manipulation which was the source of most of the price increases. And California did recover about a billion dollars from gas companies for this market manipulation. So gas prices settled down a little bit after the crises and then in 2004, they started to rapidly increase again. And by 2006, they are very high. The peak was actually in 2010. And the reason for this large increase in prices was basically competition for what were declining production from traditional supply basins.

At the time, we were looking at gas prices in the 14 to $20 range and so LNG imports became the focus of the natural gas market in the United States. Numerous facilities were constructed on the Gulf Coast and on the East Coast. There were some that were purposed to be built up the California coast, however, none of those moved forward. But Sempra did develop its Costal Azul an LNG facility in Mexico.

And then starting in about 2000, shale gas began production. So there were very rapid increases in technology development combining hydraulic factoring with horizontal drilling which produced a lot of gas. Starting in 2000, about one percent of the gas produced in the United States was from fracking. By 2010, it was over 20 percent and the Energy Information Administration [EIA] predicts that by 2035, shale gas will constitute about 46 percent of all gas produced in the United States. And since 1984 when we were on that importer, we have now have moved to an exporter of gas.

And then we saw that Citygate prices, you know, were quite a bit lower, but we have seen some spikes in supply and I can talk about those more as we move through.

And then, next slide, please.

So this slide shows a Henry Hub prices versus California Border prices. And Henry Hub is a national benchmark for pricing in the North American market. And what you see here is there’s a very tight correlation between Henry Hub and the Border prices in California. There was a slight divergence starting in 2016. And at that point there was excess Permian gas production which caused prices in the San Juan basis to also drop which led to PG&E southern border prices to fall. And then the SoCal Border prices did not fall as much. And during that period we had the Aliso Canyon leak and then we had pipeline outages which did contribute to gas spikes in the state.

Next slide, please.

In terms of recent Citygate prices and rates in California, the Citygate prices we also see a divergence between Southern California and Northern California PG&E Citygate. Largely this was due to pipeline outages. You can see there’s a divergence in 2016 but the price didn’t really diverge until -- and that was right when the leak had begun. The prices didn't really begin to diverge until about 2018 when we did have major pipeline outages on the SoCalGas system.

In terms of rates, residential rates are the highest rates and they have increased the most at about 4 percent per year. And the reason was the prices or the rates are higher for residential is because residential heating demand drive the need for infrastructure and as such much more of the costs of the natural gas system is allocated to residential and commercial customers. You can see here that commercial rates increased at about 2 percent. Industrial rates increased at about 1.4 percent. And electric generation rates actually decreased over that period, a little bit below 2 percent per year, except during that period when we had the spike in Citygate prices in 2018.

We do think that with increasing electric generation demand, at least daily draws on the natural gas systems that due to the daily ramping to meet renewable integration needs that that's going to change the use of the gas system and it may change the allocation of costs amongst these different ratepayer classes.

Next slide, please.

So in terms of total gas by total energy consumption in the state, natural gas actually counts for 28 percent of our energy consumption. And in Btu equivalent, that's more gas -- that's more gas that's used in the state than gasoline in the transportation sector. And I just pulled this slide up a couple of days ago and kind of shocked to see that we use as much natural gas as we do. And natural gas is a dominant source for building, space, and water heating and for industrial feedstock and fuel. And then it is the dominant source on the electricity system.

Next slide, please.

So in terms of recent California gas demands, gas demands have been declining since 2012, '13. You'll see that there's a lot of variation from year to year in gas demands. Weather plays a big role in both residential and commercial demands because it is for heating and it also plays a big part in electric generation. And in addition to weather during drought conditions, natural gas has been the swing supply on the electricity system in California. We have seen renewable integration needs increasing for electric generation demands. Overall annual consumption of gas has decreased, but these daily spikes are something that we're looking about -- looking towards and trying to plan around as we move forward.

So I'm now going to shift, next slide, to the gas demand forecast.

So this Energy Commission has long produced a gas demand forecast as part of its California Energy Demand. This is done every odd year. With the increased focus on long-term gas planning, the Energy Commission does recognize the need for new and different uses of our forecast and so we have been looking at what kinds of improvements we can make. In the 2021 IEPR, this is the first time that the Energy Commission collected what are called forms and instructions that contain the detailed inputs and assumptions for the utilities' demand forecasts, and they detailed the cost information that is used to calculate the rate. We have done this for a number of years on the electricity side and just initiated this process on the gas side.

And then earlier this spring, we did engage our expert panel which is composed of recognized experts in the fields of energy forecasting and modeling to review our forecast and make some recommendations about improvements. Our expert panel is made up of these experts. We had James McMann who's the former head of Energy Analysis in LBNL [Lawrence Berkeley National Laboratory] and he's an energy forecasting expert.

We have Hill Huntington who's the Executive Director of the Energy Modeling Forum from Stanford. And then we also have Alan Sanstad who's formerly with LBNL and currently with the National Science Foundation Center for Robust Decision Making, Modeling, and Climate.

Next slide, please.

So the expert panel gave us the Good Housekeeping seal of approval for our forecast. They found the forecast methodology is reasonable. They noted that the natural gas demand forecast uses the same methodology as for electricity, and they have previously reviewed our electricity forecast. In addition, they have reviewed our transportation forecast.

They did note that the forecast should continue its formal tie to the electricity forecast. They believed that this is increasingly important especially with the anticipated acceleration of electrification in residential and commercial buildings in California. And then the other major recommendation is that we needed to improve the transparency of our forecast through stakeholder engagement. We should do better model documentation and we should make the model code more accessible and replicable so others understand our forecast.

Next slide, please.

So they identified a number of near-term improvements. The vetting and making the forecast results transparent. We use what's called the Demand Analysis Working Group for our electricity forecast as well as the transportation forecast. They recommended that we begin to do that for our gas forecast.

They also recommended that we translate the residential and commercial end-use models to modern platform. They want us to incorporate the most recent surveys, the Residential Appliance Survey and the Commercial End-Use Survey into the forecast. And they suggest we re-examine the econometric specifications as a natural gas model and re-estimate the equation that are routinely updated with new data. They have recommended that we break out into separate planning area. The gas deliveries by interstate, they go directly to end-use customers in California in addition to the two major gas utilities, PG&E and SoCalGas.

And then they have recommended greater collaboration within our own assessment division so that we can discover and correct data errors or misinterpretations, excuse me, and be able to identify industry changes.

Next slide, please.

In terms of midterm improvements, they have recommended that we develop approaches for forecasting under different weather conditions. We do average conditions now and we do an average annual demand forecast.

In the gas planning world, 1 in 10 condition, 1 in 35, and 1 in 90 are conditions that are used for basing reliability standards so it’s important for us to have a forecast that can be used in that arena. They’ve asked us to craft usable, simple models to calculate natural gas transportation rates that logically escalate and that with expand over time and I mentioned earlier and will be talked about more this afternoon. We do have our natural gas transportation rate model and we have developed it so it can expand in the future.

They have recommended that we continue to issue and expand our forms and instructions to collect forecast information in future years. They have recommend --

COMMISSIONER GUNDA: Melissa.

MS. JONES: Yes.

COMMISSIONER GUNDA: Excuse me. I apologize to interrupt you there. I think we are one slide behind. I think we should move forward another slide. Yeah, thank you.

MS. JONES: Oh, sorry. I have my type in front of me so I can't see who is on the screen there. Thank you.

So in terms of midterm improvements, I mentioned that forecasting under different weather conditions. We have already started with the natural gas rates model. We're continually to do forms and instructions in the IEPRs. And then they had suggested that we enhance our understanding of industrial end uses, especially those that cannot be electrified.

And then finally in terms of long-term gas improvements, forecast improvements, they suggested that we develop a forecast for hot, dry summer conditions. And on our July 9th workshop, we represented some initial thoughts about how to go about looking at summer demands. They're suggesting we develop more granular disaggregation in our forecast so they can be used in hydraulic modeling of a gas system, both geographically and hourly. This is especially important to reflect to the electric generation burn on the system.

We'll need to capture climate change impact, temperature, and occurrence of extreme events, both hot and cold. They heat dome and polar vortex type event. Ensure time in the process to iterate back and forth between price and quantity. They suggest that we get daily and hourly gas send out from utilities by customer class. And they recommend that we continue corroboration with utilities in developing more sophisticated forecasting methods corresponding to the new and changing circumstances in the gas market.

Next slide.

And with that, I think I'm done with my presentation. Thank you for listening this afternoon.

MS. RAITT: Thank you so much, Melissa.

For our next speaker is Anthony Dixon, or A.J., and he is the lead gas price modeler in the state through the Energy Assessment Division. So Anthony will be covering the CEC preliminary natural gas market results.

Go ahead.

MR. DIXON: Thank you.

MS. RAITT: Thank you.

MR. DIXON: All right. So, good afternoon, everyone and Commissioners. I am Anthony Dixon or A.J. I am the lead natural gas market forecaster, and I will be going over our preliminary results for both the NAMGas [North American Gas-Trade Model] model and the new end-use rates and deliver price modeling that we are working on.

Next slide, please.

So the NAMGas model we've been using for many years. It's a well vetted model using the MarketBuilder platform as a general equilibrium model. Some of the updates to this year's model, of course, we always do North America demands to reflect the current market conditions. We updated the pipeline capacity throughout all of North America including LNG infrastructure and a lot of new information on the natural gas reserves and the costs. And we always vet these out to the public and also internally and with Aspen Environmental.

Next slide, please.

So the kind of the flow of what goes on with our modeling efforts. The NAMGas model has three major inputs that we work on. Those three are our resource model which works with the capacities and costs associated with production of natural gas throughout North America. We have a small M model which is our demands throughout North America. And there's a caveat with that where we do not use small m model to forecast demand in California and for power gen and the WECC. There's two other inside the Energy Commission that does that modeling that we use their information. And we do infrastructure research.

Off from the NAMGas model go directly to the PLEXOS, or they go through a burner tip model and gas rates models and then they get put into the production cost modeling. The rates also go to a delivered rate model which go to our demand forecast and then those go back to us. It's kind of an iterative process that we work out.

Next slide, please.

NAMGas model in a simplified version, it's supply basins that are connected to interstate and intrastate pipelines which are connected to demand centers. And the model basically calculates equilibrium across all time points across all supply and demand at the same time. And it gives us supply, it gives us production, it gives us flows, and it gives us prices.

Next slide, please.

So some of the improvements and changes that we did this year, we changed it from an annual model to a monthly model. That gives us a model seasonal demand patterns that we did not have before and also gives us the ability to account for storage, which we never had before. And with so many things dealing with storage, especially here in California, that is a great addition that we'll be able to look into and see the effects on crisis.

We have a new resource allocation model. That's our supplies. Usually before we were given just the numbers by consultants and that was what we took so now we actually develop them ourselves. And we did a lot of streamlining with the nodes inside the model to make it more real worldish and also to streamline it and just make the model run a lot a better.

Next slide, please.

With the corporation with IEPR, we do three common cases, the high demand, mid-demand which is a business as usual kind of case, and a low demand case. We will hopefully, depending on time, be able to do some more sensitivity analysis for the final run so we'll be able to look at a few more things throughout North America.

Next slide please.

So some of the key assumptions to start the model. These are all kind of references to the model. The model just takes these and when it does its balancing, it will change demands, it'll change prices, depending. Basically for renewables, we make sure that we assume that in all cases that California and all other states have met their RPS targets that they have set.

We do a lot of research into these RPS targets for all the states and including Canada and Mexico, if they have any. We use a lot of EIA data, so their update are able to pull North America data. We also, when it comes to data, we also look at things like Canada. We deal their energy information and also Mexico's.

Next slide please.

And then this slide will show us the demand inputs that we use for California. This is California specific. We do not change these. Basically the numbers are a combination of both the PLEXOS modeling and the California Energy demand forecasts. We just take these numbers, we put them into the model, we turn elasticities off so whatever they give us is what the model will spit out as well. The only thing that changes is the price. We don't model these, we don't change them, we don't do anything, we just take them from the other forecasters.

We do do some extra work with the PLEXOS team where we model a few times. Starting this year, this is the first year we have been able to do this. We actually iterated between each other five times, get our results to get a little better equilibrium.

Next slide, please.

Then to continue on with some resources and their costs, how we change them for each case. One of the big things to kind of notice is the proved and potential resources even in the mid-demand case and this kind of goes into our results later on, is the fact that proved resources keep growing even through we're pulling record production. Last year wasn't record production, but we've been pulling record production every year, usually, and proved in potential resources keep going up. Our technology and what gas we can get to keeps going up an they're able not only to produce more of it, but to produce more of it at lower and lower costs.

Next slide, please.

So these are our U.S. demand projections that -- from our modeling efforts by customer class and also overall. And they do track very well with EIA's latest annual energy outlook.

Next slide, please.

So count some preliminary results directly from the model. Henry Hub is one important that we really look at because that is the national benchmark. And as Henry Hub goes, so does the Country and even LNG, that's how they price LNG exports and costs. It's a very important hub, it always has been. It used to be -- before actually, it used to be even more important because so much gas used to flow through that point.

We see prices increasing over the timeframe, not a lot. Once again that's because supplies being so high. The one thing we do notice is more seasonality as we go further along into the forecast. And that's as demand kind of increases, puts pressure on pipelines aren't being as expanded as fast, but demand is growing. The pipelines won't run out of capacity, they're just more -- losing more of their slack capacity. And this will cause times of high demands in stresses, especially during the winter to increase prices.

Next slide, please.

Our supply basins. Melissa talked about our supply basins here in California, from Canada, the Rocky Mountains, the Four Corner regions, and also western Texas through New Mexico, the Permian Basin. Once again, prices will remain relatively low due to low cost of fracking, associated gas production, just once again lots of gas to be produced.

To note, you see the higher peaks in the later seasons. It's once again, as demand increases, the winter demand, how the model works, increases more than other seasons so you're going to see those higher spikes later on unless more pipeline, more capacity, more storage, something to mitigate those issues is built.

Next slide.

So the California border crisis. These are all the major points coming into California compared to the Henry Hub price and they all track right along with Henry Hub. We see Malin being lower that's because they can pull both Rocky and Canadian natural gas, which is lower costs -- low costs and steady supply. PG&E Topock is right along with Henry Hub. SoCal border is above and that's because there are issues along the system. Even though they're after the border, they still affect the prices at the border.

Next slide, please.

So our prices for the PG&E Citygate, you see them climbing and getting more and more high peaks during the winter. One thing is the high demand case, even though it's a low-cost case, the fact that demand increases so much that the winter spikes cause the annual average to actually increase above the mid-demand case. And this is, once again, barring things like drastic productions, demand or more pipelines or more storage or something to mitigate these issues.

Next slide, please.

We also see the same phenomenon happening at SoCal Citygate where the high demand case actually reaches the mid-demand case. One thing of note that we noticed in the monthly prices is the fact that we actually start seeing a summer peak for SoCal Citygate prices. And this is actually starting to be seen currently, but more pronounced as the years get later on.

Next slide, please.

So now we’re going to move on to our new model. This is the transportation rates for California.

Next slide.

So this model is trying to capture is the transportation rate from the border into the Citygate for the different customer classes within California, the residential, commercial, industrial, and including the backbone and local transmission power generators that are connected to these pipelines. That would pay at cost at the border, but they can still pay a transportation rate.

Gas utilities only purchase the gas for their core customers. And noncore buy their own gas and then pay either the backbone or local transmission rates or combination to get it to their end use.

There’s also another component which is delivered price which would take these transportation rates and add them to a commodity price which is produced by NAMGas at the border or at the Citygate hubs. And this is also the same kind of concept that we use in the burner tip model as it’s called the burner tip price. That’s for the electric gas.

Next slide, please.

So we use these in our demand forecast, our gas price forecast, the production cost modeling. (Audio cuts out), they're used in the IEPR process, they're used in the PUC. WECC uses these prices, they're really used a lot.

Some of the old methodology were just kind of an average way, an average class. We didn't do any separate calculations. We also didn't do any escalation rates. So some of these improvements are to kind of look at those things and to improve upon them.

Next slide, please.

So this is kind of just a quick breakdown of how these rates come apart. You know, we have our transportation only revenue requirements, separated out by the class revenue requirements for each class to get a spread between the different classes which would be residential, commercial, industrial, and power gen. We escalated the revenue requirements each year and then you basically multiple by those escalation factors and then divide by the forecast and annual demand which is from the 2019 IEPR forecast. And then you end up with a final average rate. That rate has been added on to the burner tip price or the end-use price so we can get a delivered price.

Next slide, please.

So some of the major factors that drive these rates, of course the revenue requirement and its annual escalator, how much we're changing these prices each year, the class revenue allocation factors and the forecast and demand. So basically kind of think about it if the revenue requirement is held consistent but demand climbs, then rates will increase. If demand -- if demand is held constant but the revenue requirements go up, then prices would increase. What we're kind of looking at here in California that might happen is the fact that the revenue requirement might go up and demand increasing so we will -- should see rates increase.

Next slide, please.

So this is what we saw with the rates and with our current modeling, our current escalation factors which the escalation factor is 2.3 percent. That's something in the next slide I'll talk a little bit more about.

You can see the residential rate increasing the most, especially down in San Diego Gas and Electric, with the industrial, PG&E, kind of holding constant in commercial in between.

Next slide, please.

So to speak more about the escalation rate, this is one of our things that we really like input from the public and really be able to come to consensus. Currently in the model is 2.3 percent, we can change it to whatever is seen as the best rate. You know, E3 and their work, they have a 6.5 percent increase for the state, but theirs is also only residential and across the state as a whole.

On average, the last 12 years you see PG&E was increasing about 6 percent, SoCalGas four and a half, San Diego seven and a -- or six and a half. But in the last six years, it's definitely changed, especially for PG&E as a lot of their increasing rates, there's a lot of the San Bruno work and the reliability and safety work that they had done. And now that's going away so it's a big question about what rate we should use and that it's one of the most important factors in the output. It's where we really use some input.

Next slide, please.

So we kind of go off talking about those revenue rates. We are 2.3 percent. Should we use the 12-year average, should we use a less average? Just something that makes sense and is very -- has some sound logic behind. So how to -- should we change how things change for the allocations between the customer classes. Should residential percentages change, you know, should those change over time and if they do, what would the basis for that be.

Next slide, please.

Just to kind of go over again about priority, had iterated this, about the delivered price which is the commodity price plus the transportation rate for the different customer classes.

And next slide.

This kind of -- this will show the results of that for the three utilities. This is the mid-demand case only on annual average. It's key to note that the rates increase about 2 percent per year which is really close to the revenue requirement escalation factor that we had of 2.3 percent. Just kind of reiterates that fact that that's a very important factor in how we change the rates.

Next slide, please.

And that is all. So thank you very much and I'll turn it back over to Heather.

MS. RAITT: Great. Thank you, Anthony.

So our next speaker is Ryan Ong. And he is the Natural Gas Market Modeler in the CEC Energy Assessment Division.

So go ahead, Ryan.

MR. ONG: Good afternoon, everyone. I'm Ryan Ong and I'm the Natural Gas Market Modeler with Supply Analysis Office.

Today I'll be giving an overview of the burner tip gas model, discuss changes made to it, and talk about observed results.

Next slide, please.

So what is the burner tip model? The model estimates delivered natural gas prices for use in electricity production cost modeling, like the PLEXOS model. The burner tip yields prices for PLEXOS's fuel groups through the Western Electricity Coordinating Council region depending on location.

To determine the price, the burner tip is in excel workbook that aggregates commodity prices and transportation rates together for hubs. It should be noted that the burner tip only forecasts prices within the WECC. Commodity prices are pulled from NAMGas's monthly price model that covers three IEPR common cases, mid-demand, low demand, and high demand.

Commodity priced is simply the natural gas price at any market trading location. Transportation rates involve interstate and intrastate pipelines. Interstate pipelines cross multiple states while intrastate only involves California pipelines. Interstate pipeline rates are determined by pulling a pipeline and utility company's published tariff rates. For California rates, a new transportation rates model was developed for intrastate pipelines. The burner tip uses select rates from this model for hubs linked to PG&E, SoCalGas, and SDG&E.

Next slide, please.

In taking a deeper dive in the commodity prices and transportation rates within the burner tip, rates are in nominal 2020 dollars per one million British thermal units. Interstate transportation rates are set over a long period of time and no escalation is factored. In addition, the interstate rates is -- are FERC approved rates.

California utility transportation of PG&E, SoCalGas, and SDG&E were pulled from the sectorial transportation rate model developed by ASPEN Environmental. Unlike the interstate transportation rates, the California transportation rates vary over the forecast horizon. And as A.J. mentioned, this is because the transportation model accounts for each entity's revenue requirement, CPUC adopted cost allocation, and assumed escalation factor which as A.J. said was 2.3 right now.

Next slide, please.

In examining the previous burner tip methodology, it was determined that improvements can be made to better reflect the natural gas market. Notable improvements include incorporating NAMGas's new monthly price forecast compared to the previous annual forecast method. Revising market hubs that link to PLEXOS's fuel groups by updating proxy hubs to market hubs in proximity to power plants.

The revisions that are identified to liquid trading points where power plants would logically purchase fuel. Resources used include looking at several maps like Energy Information Administration, facility map, and applying logical judgment to define which prices should be applied within the burner tip.

We also assessed natural gas delivery flow rates to develop a weighted hub price average to reflects supply options for some location with the use of PointLogic. The transportation rates reflect natural gas flowing through pipelines to electric generators. In some instances, generators receive delivery for more than one market hub. And as mentioned, we update interstate pipeline transportation rates in using newly developed California utility transportation rates model. With these changes, the model better represents price formation in the gas market with the use of market hubs and existing transportation conditions.

The burner tip price also captures seasonality within the new monthly NAMGas price forecast compared to a manual static adjustment made within the previous burner tip version. Changes were vetted internally and through ASPEN Environmental.

Next slide, please.

This table highlights a few changes that were made within the burner tip that better represent market conditions and gas prices that electric generators pay. Changes are broken down by fuel groups, which are groupings of power plants available in the PLEXOS model. One change included going from a Seattle proxy hub and Northwest transportation to a Kingsgate market hub and a gas transmission northwest transportation rate.

Other changes involved switching from the Mexico Baja proxy hub to the Ehrenberg market hub, using Sumas hub West Coast Transportation and northwest pipeline instead of a Portland proxy hub and Gas Transmission Northwest, Oregon fuel groups. Or switching from a Las Vegas proxy hub in Opal market hub.

A complete list of the changes will be documented, updated in the burner tips website after this workshop. And changes also been noted at the end of this presentation as well.

Next slide, please.

So what happened when prices -- what happened when we changed methodology for prices? A low -- lower delivery price consisting of commodity prices and transportation rates to electricity generates occurred for all burner tip price locations where revisions were made. This graph shows the difference between the Seattle and Northwest Transportation hub compared to the Kingsgate and Gas Transmission Northwest Transportation market hub.

You'll notice the new method's burner tip price, the solid blue line, is lower than the old burner tip method, the dotted orange line. The tables below reflect the commodity price and transportation rate changes that occurred for this hub. The price decrease is largely driven by a lower commodity price that mimics actual market conditions. By changing to the market hub method, most hub prices are lowered when compared in using a proxy hub. It's also important to note, a double counting of transportation rates likely occurred with the proxy method. The updated burner tip eliminated this and caused prices to be lower as well.

Next slide, please.

So this graph represents an average of all 31 monthly burner tip hub prices throughout the forecast by common cases from 2020 to 2030. So I added up all burner tip monthly prices and divided by 31 hubs to come up with an overall average. You'll notice seasonality is captured with the monthly analysis with demand peaking in the winter and declining in the spring. Prices also steadily increased over the forecast for all common cases. The lower commodity price under the new methodology also resulted in lower starting and ending prices compared to the proxy methodology.

Next slide, please.

The California's market hubs were matched with the utility transportation rates model based on existing market conditions. Changes include a hub location from Malin and Topock from the PG&E backbone and linking SDG&E to SoCalGas instead of using the proxy hub. For Kern and Mojave and Southern California fuel groups, transportation is included in the market hub price. Kern, Mojave, and SoCal oil production are also now linked to Wheeler Ridge instead of Daggett/Kramer. Southern California oil and gas production also includes PLEXOS's TERO group.

Next slide, please.

So rates for California also primary decreased because of lower commodity prices. This table just highlights the mid-demand case, but prices moved in the same direction for each burner tip location price, both low and high demand cases as well. Exception, the Central Valley burner tip price increased because it was switched from Daggett/Kramer to Wheeler Ridge.

Next slide, please.

To summarize, changes in the model resulted in a lower burner tip prices compared to the previous methodology primarily due to lower commodity prices and cleaning up with double counting of transportation rates. Seasonality is also captured within the monthly NAMGas price forecast compared to the manual static adjustment that was made within the previous burner tip. And with these changes, the model better reflects existing market conditions than in the past.

Next slide, please.

And, again, a list of the changes made to the burner tip can be reviewed at the end of the slide deck. Also the slides will be docketed as well. And thank you for your time.

MS. RAITT: This is Heather. Thank you, Anthony and Ryan.

Commissioners, we have some time if you have any questions or comments you'd like to make.

COMMISSIONER GUNDA: Yeah, thank you, Heather. I just have, I mean I have a few questions, but I think maybe we can just tackle one question from the broader, you know, stakeholders' awareness here.

So, Anthony, you kind of talked about the transportation rates and then specifically invited public comment on there that 2.3 percent, I believe, is what you showed us what's what's baked into the forecast right now.

I think it's a two-part question. One, how does that impact Ryan's modeling when Ryan talks about the transportation side, is that the same -- same number that we're talking about?

MR. DIXON: No. So this 2.3 percent is the revenue escalation to the utilities within California only. We don't escalate any of the rates outside of California for the interstate pipelines. As we've looked into the history and we looked at it, they don't change very much over time. Their system is done differently as they don't do a rate case every two years. Pipelines when they even get built basically commission for 15 to 20 years on fixed prices from suppliers and transportations across their pipelines. And the only time they really change rates is if they're losing a bunch of those contracts at the same time or if they decide to expand the pipeline's capacity or build new lines. So we couldn't find any justifications for changing rates outside of California. And that's all for FERC approved groups.

COMMISSIONER GUNDA: That's great. So that's one.

So in the second question, thanks for clarifying that. The second question in terms of the 2.3 percent escalation rate that we're using here as a starting point, I believe, as team members where you showed the escalation grade and PG&E being close to 6 percent. So why do we -- where is that kind of difference coming from gentlemen. And it looks like the other numbers were kind of from the higher end too. So do we have kind of reasons that we start off at a lower level?

MR. DIXON: The 2.3 percent was just the rate of inflation and, like we said, we just kind of developed this model. We got it working, made sure things look realistic and match what's been out there. The 6, little over 6 percent that we saw where PG&E was their average in the last 12 years, but once again if you only look at the last 6 years, they actually had a negative, you know, rate. So that's where we're kind of like justification what should we use?

We know in the E3, they used a six and a half percent. Once again, that's only for residential and also the fact that how they kind of computed it with just using the EIA data, that was an average of the border price versus Citygate price so that price includes things like effects of the Aliso or effects of seasonality, doesn't really show the true transportation rate changes. And that's kind of where we wanted to get the input was to really get this more robust and find a good rate that would work.

COMMISSIONER GUNDA: Great. So just the high level, who others do the price forecast in California? I mean, you said the, you know, just now for the residential side, and what are any other numbers we might -- that might be used out there? Transportation rates currently.

MR. DIXON: Using our rates?

COMMISSIONER GUNDA: No, no, no. Just in development of the obvious kind of analysis. Are we seeing any other escalation rates that are currently being used?

MR. DIXON: No.

COMMISSIONER GUNDA: Okay. Got it. I'm glad that you put that on kind of the table for public comment, so I look forward to getting more information on that.

So, Melissa, looks like you wanted to add something?

MS. JONES: Oh, I was just going to say, I think we're the only ones that do a rate forecast. So the one that was used for the CPUC in the en banc was just an escalated rate, I think it was exactly the same. But, yeah, there is this question about how much do you escalate because how many additional costs are being added into the rate base. There's a lot of safety work that's already been done in the PG&E system whereas as much hasn't been done on the SoCal system so there might be a justification for a higher escalation in SoCal versus PG&E. And so those are the kinds of factors we're trying to look at and get a better sense of as we move forward.

MR. DIXON: And to kind of further that, that's one of the nice things about how this model was developed whereas the previous model, the en banc one, was just one rate for the whole state. We actually have it broken out by PG&E, SoCal, and San Diego. We can have a different rate for each one. We can change the rate from year to year. We have that capability. We need that kind of sensitivity even this for sensitivity analysis, we can change things around.

COMMISSIONER GUNDA: Great. Anthony, thank you so much. I appreciate all the work that the team's doing.

I also want to recognize that Commissioner Monahan joined us on the dais. So unless the other Commissioners McAllister and Monahan have any questions, I'll just look for a queue.

COMMISSIONER MONAHAN: I don't have any questions. I actually just joined a few minutes ago so I unfortunately missed the presentation. I'm late to the dais.

COMMISSIONER GUNDA: Thank you, Commissioner.

COMMISSIONER MONAHAN: Sorry about that.

COMMISSIONER GUNDA: Thank you. Thank you for joining.

Yeah, with that, I will pass it back to Heather for the next segment.

MS. RAITT: Okay, great. Thank you.

So I don't see any questions from attendees within Q&A. So we'll move on and so to utility presentations.

And just a reminder, if the folks have a questions for utilities during their presentation, you can submit it by writing a question in that Q&A feature in the Zoom.

So moving on. First, we're going to have a presentation from PG&E and Andrew Klingler is, excuse me, I'm sorry I just mispronounced your name. He's the Senior Manager of Rate Architecture and Cost, the Pacific Gas and Electric Utility. And he's joined by Todd Peterson, Kurtis Kolnowski, and Amy Kouch.

So go ahead, Andrew.

MR. KLINGLER: Okay. Can you hear me?

MS. RAITT: Yes, great.

MR. KLINGLER: Great, great. All right. So we're going to talk a little bit about our -- about our internal gas forecast and it will be specifically focused on the -- in the Integrated Energy Policy Report presentation that we did earlier in the year.

PG&E does not have an approved internal forecast subsequent to that and it is also, that is drawn directly from the California Gas Report (CGR) as a fairly standardized view.

Can we go to the first -- there we are. Thank you. All right, thanks. Next slide.

So just to situate us, this is an overview of the 2020 California Gas Report forecast and the 2021 IEPR gas filing is based on that forecast. The CalGas report, as many people will know, is filed every two years according to the CPUC decision. And this decision tells the IOUs to work cooperatively to prepare an annual report. And so this is done with a certain degree of overlap and coordination on timing and vintage of information.

And so we aim for a consistent forecast, although there are sections in the CalGas report that address different regions within the state. The major input assumptions include electric demand, the natural gas and GHG prices, includes hydro assumptions, and future resource assumptions on the electric generation side.

Thanks. Next slide.

The CGR presents the outlook for natural gas supply and demand over a long-term planning horizon. So the projections are intended for a long-term planning purpose and there are two different forecasts. There's an average temperature year and there's a cold and dry hydroelectric condition year. And the -- so average temperature year is also sometimes referred to as 1 and 2 forecast. The cold and dry year for the CalGas report is a 1 in 10 scenario. There are other forecasts and other situations where a different percentile is used for those. So that's something to watch out for.

Now the methodologies and presentations there for the CalGas report used as backup information as needed here. So the forecast components include -- this slide sort of lays out the basic structure of PG&E's approach. There are basically, there are two large subsections of the forecast, and one is what you might want to call the base forecast which is driven by historical information and weather and economic development. And the other is the more forward-looking market and policy driven kind of forecast. And that's where you see on the top the energy efficiency forecast, the building electrification forecast, and the electric generation forecast. And so those two pieces operate somewhat independently and then are integrated to produce the final forecast.

The historical and data driven regression models, they -- we have regression models for each of the major customer classes as well as non-regression models for the smaller NGV and interdepartmental classes. And those produce this sort of a base usage forecast. After that is done, the -- what we sometimes call the load modifiers, the energy efficiency and electrification, and electric generation forecasts which are produced through a combination of modeling and subject matter expert consultation are produced and those are layered into the regression model results to produce forecasts of the various customer classes who are noncore in the total system.

Thanks. So that was sort of the big picture. Now we move on to what was actually done for the CalGas report and for the IEPR form file. Now this slide is a little dense. We compacted some information into sort of one big unit there. This -- here we look at the basic results and regression drivers for the -- for forms that go into Forms 1.1 through 1.7 on the IEPR forms. These results contain information to the 2020 California Gas report. It has -- this year's, we have the average for 1 and 2 gas throughput. We have the cold and dry. We do not do a hot year. It sounds like we may be aiming for that in the future for a hot summer, but that is not for usage reasons a typical stress scenario for gas. We also provide recorded and weather normalized recorded data by category.

You can see the basic summary chart for the forecast off to the right-hand side. That's the PG&E service area gas throughput forecast including core, noncore, and EG.

Now the drivers for this forecast are the components from diagram we were looking at on the last slide. We include the recorded sales from PG&E internal data. We include temperature history from PG&E weather database. We include internal rates forecast and economic assumptions from the appropriately vintage Moody's update which we are a subscriber to. Those are the inputs to what the regression models that we talked about before.

Apart from this, we have the load modifiers. Those are the electric generation and the building electrification and energy efficiency and those are going to be described in a little more detail in following slides.

So to return to those regression inputs, a lot of them are weather and economic drivers apart from just our internal usage data.

Oh, can we back up a slide? Yeah.

So that includes our historical age heating degree day data and so our forecast includes that expected heating degree day and a simple climate trend added on top of that. The cold scenario is just a percentile calculated assuming a bell curve distribution for the monthly heating degree days. So that's our 1 in 10 that we talked about a moment ago.

As we said, there's no cooling degree days because we're doing a heat stress scenario. One thing that people have asked about that we have not historically done and may be valuable, but we have not done this in the past so it's a significant data exercise, is to break out HDD data by location and map the load forecast to that.

For economics, we subscribe to Moody's service. The residential forecast is driven by population count and households. And the commercial forecast is driven by gross state product localized to the PG&E service area and employment type so that means you checked or service industry or manufacturing, how it breaks out that way because that will drive different components of the throughput.

All right, thanks. Next slide.

Now we move on to energy efficient and I'm going to turn it over, I believe, to Kurtis.

MR. KOLNOWSKI: Okay. Thank you, Andrew. Apologies if you can hear background. There's a car driving, emergency truck driving by.

But anyway, I'm Kurtis Kolnowski, Expert Analyst within PRF, or Portfolio Resource Forecasting. We -- our group models these load modifiers as well as electric generation, some of the other resource categories.

I'll talk right now about energy efficiency. It's actually pretty straightforward on the natural gas side since we adopted the CEC's forecast of EE. From the IEPR forecast, you'll see a pretty simple flowchart here where we take the committed EE so those savings that have like a policy or program or code of standard, actually, enacted on the books.

And looking at all the different customer clients, residential, commercial as well as AAEE or Additional Achievable Energy Efficiency which comes from several of CPUC's potential and goals models. And those are where we get future E programs and codes of standards for I believe the CEC also uses or merges a couple of other sources such as beyond codes of standards study which looks a little bit further down the line. But essentially we're looking to take that data for the PG&E service area and adapt it to our models and use it going forward.

So not a whole lot on this one. I will turn over to Amy to talk a little bit about building electrification.

MS. KOUCH: Awesome. Can we move to the next slide?

All right. Hi everyone, my name is Amy Kouch, and I'm the forecaster who leads the building electrification forecast at PG&E.

And so we've fill Form 1.10 of the gas IEPR with the building electrification forecast results. And so I'll be walking you through the high-level methodology of this forecast.

So for our forecast, we consider both the residential and commercial sectors and within those sectors we have two building types. We have new construction which are new homes or buildings that are constructed to be all electric. And then we have retrofits which are existing gas appliances that are switched to electric at the end of their device lifetime. We then create policy scenarios regarding electrification and then subject matter experts within PG&E will weight the likelihood of these scenarios to occur in order to get a final point forecast. And then our ultimate outputs are the electrical impact, the gas load impact, and peak. These outputs all come from the same model so within the same policy assumptions in order to come up with these different results.

And so you might be wondering what our scenarios are actually formed by. You can see that for new construction, it’s really driven by policy. These are our Title 24 building codes and Title 20 appliance standards which are updated on a three-year code cycle basis. They also consider reach codes that are passed by local entities. For example, if a city passes a natural gas ban. We work closely with our internal codes and standards team in order to keep updated not just on what current policy is occurring but where we expect future policy to go or could happen until we end up with a summary, like metric of what percent of buildings are considered to be all electric.

For retrofits, on the other hand, it’s driven by economics as well as policy and so we create scenarios based on consumer adoption of electrified appliances. So we primarily look at space heaters and water heaters, but we also consider cooking stoves, process equipment, and dryers as well. And so the metric we get is percent of existing gas yield appliances that are electrified.

And I'm happy to answer any questions in the Q&A. I'll now pass it back to Kurtis to discuss electric generation.

MR. KOLNOWSKI: All right. So the final couple of slides we have are on electric generation forecasting. So this gas, fire, electric generation, climate cycles, gas turbines, reciprocating engines, the various co-gens. The power plants would take the gas off our backbone or local transmission system, convert that to energy, and either use that to serve load on site or sell into an energy market such as the CAISO.

So what you're seeing here is results from the California gas report for PG&E service area. Results are in million cubic feet per day and that's -- that would be an average over the 365 to 66 days in a year. There's a couple of things here. The first is since this is a CGR, 2020 was a forecasted year, that's when the forecast was still being developed. And you'll see lower Southern California gas prices decrease. EG firms in North Cal, really in that 2021 period onward decreasing renewable portfolio standard requirements while reduce EG throughput as well. Since those are typically cheaper, they end up generating intermittent resources generate first and EG follows more on the margin.

And then finally, in this 2030 to '35 period, you see a slight uptick and that's driven mainly by building electrification or additional electric load on this system. There's -- once you're getting out that far, there's a little bit more uncertainty in what's actually going to happen. Different resource acquisition exists where de-electrification, actually, things like that could result in a pretty wide range in that timeframe, anywhere from really know that increase if there's electrification load is survive renewables to something like you're seeing here. And PG&E forecasts, both in average and in CCR 1-in-10 Cold Year, and you'll see that we both backbone and local transmission plans on here.

So going to Slide 9.

Okay. So a little bit about the methodology that we used to forecast electric generation. We're using production cost models. For the CGR, we used MarketBuilder which is a legacy gas generation model. And recently we've been working on adapting actually the CEC's IEPER PLEXOS model for use in EG forecasting. So similar concept, more details. And essentially, we model all the power plants within the WECC loads for those various regions, interconnections, and go step hour by hour and optimize the least cost solution for what resources to use to generate to meet the load.

I noted a couple of major assumptions that we use for electric generation forecasting on this slide. One of the big ones is electric load. So CEC's IPER report is used plus we add our own building electrification forecasts within a short-term timeframe. Electrification isn't the biggest driver but you saw the '30, '35 that starts to increase a little bit more. Gas prices are a big driver. For this one, we use prices develop within the CGR. Renewable portfolio standards it's 50 percent by 2030, consistent with SB100. Also a lot of additional battery storage, a little bit of pumped hydro. Hydroelectric assumptions so how plants within California and then across the WECC.

For generate using hydroelectricity, it's a combination of run of river type systems, mostly out of state that generate as the water's available. And then in California we have a little bit more control over that. So you can optimize the water levels a little bit more. Once their cooling plant retirements, so the repowers, the retirements coming up, Diablo Canyon in '25. CO_2 prices from the forecast. And then finally on transmission capacity from WECC-wide data.

But there's a lot of assumptions. We work in the CGR and elsewhere with other entities and marketing groups to develop consistency around these.

And if we can go into Slide 10, I just want to talk a little bit more about assumptions.

So this is a little more forward looking here. Up to now, we've been talking about how we forecasted to date. I just wanted to call attention to a couple electric generation forecast assumptions that we've identified as pretty critical for the future. There's interest in these, there are substantial drivers, and the environment might be changing (audio lost) in the future.

So we talked about this meeting on July 29th, I talked about gas system interdependencies here and we're currently engaging in statewide studies and working groups such as the IRP, IEPR forecast here. California Gas Report helped address these at a statewide level, but I just wanted to take a quick second to talk about a couple of these that we're looking at.

Hydroelectric generation, as you know, we're in a drought right now. Over the past 20 years, we've observed that there is a trend in declining hydroelectric generation. I want to note, this resource class is highly variable. If you were to draw a line as to what an average looks like, many years would be above or below that line. In fact, in a need for thermal generation so looking into that, assessing a wide range of conditions and seeing what could happen in the future is pretty important given where we are right now.

Demand forecast is the next one. And there's impacts, two impacts to call out here, electrification and climate change, potentially. And these can impact both the magnitude of the load needed to be served which would require additional resources and also in climate changes is the variability on this system. So a couple hot days or week, cold winter, those can have a pretty big impact on how electric load is required for -- or electric generation's required on a specific periods of time.

Imports next. So looking at what WECC-wide independencies here. I guess I could call it high -- periods of high overall demand within the WECC, such as some of the heatwaves that we saw earlier this year can constrain imports or resources of the state willing to be -- or available to be imported into California. So really looking at that. I know that's part of some of the recent preferred system plan work. The CPUC has looked at what our import constraint should be in a peak condition.

The next one, future resource additions or retirements. So these impact the resource mix as far as the state's goals. Just wanted to note that. In this case, there's a lot of ongoing work on this one. New orders and procurement orders, system plans, things like that. Keeping up to date on those, making sure as those come out, we model those changes, understand where the future's going, and as we transition towards the decarbonization path. We really need to just make sure we stay on top of those as they come out.

Finally, this last one, fuel prices. This one doesn't necessarily affect generation at like CAISO or statewide, but differences between Citygate prices you saw in previous slide decks from the CEC that differences, there's differences in PG&E and SoCalGas Citygate prices. These can reflect -- these can cause favorable conditions for generators and one region of the state over the other. And understand those price (indiscernible) can help recognize variation of gas to put on utility gas systems.

So a lot of these things that we're looking at working -- want to just, yeah, just draw attention that as things that could have an impact in the future.

And that's actually the end of our slides. So thank you everyone.

MS. RAITT: Great. Thank you so much to A.J. Andrew, Todd, Kurtis, and Amy. Appreciate that.

So next we will turn to Southern California Gas Company's presentation on their gas demand forecast. And the two presenters, Sharim Chaudhury who's the Manager for Cost Allocation and Rate Design and also Jeff Huang, who is the Senior Resource Planner.

So go ahead, Sharim.

MR. CHAUDHURY: Hi. My name is Sharim Chaudhury. I manage the rate design and demand forecasting group for SoCalGas and San Diego on the gas side. And along with me, we have Jeff Huang who’s going to talk about the gas demand for gas fired electrification.

Next slide, please.

So we’re going to talk about a long-term demand for custom models and basically major assumptions underlying sort of each of those models. So we have models for our core market segments and we have separate models for noncore customers including electric generation customers. And we’ll talk a little bit about the weather design because it’s an important element of long-term demand forecast for our customer segment whose gas demand is weather sensitive.

Then we’re going to talk about cold year demand. As PG&E talked about in the California Gas report, we provide two scenarios. One is sort of average year demand and other is cold air, dry hyrdo demand. These two scenarios. In addition, we also will briefly talk about the peak day demand for our system. And then at the end, we’ll share a few slides about our forecasting results from the 2020 California Gas Report.

Next slide.

This is an exhaustive list of the long-term demand forecasting model we have by core and noncore customers and also by wholesale customers. So as you can see in this table, for within the core segment for residential, core commercial, or industrial, we use end-use forecasting models similar to what CEC has.

Then we have, you know, put in natural gas market segment and we have fuel gas engine customers. And gas air conditioning cost too much. For them, we pretty much use a simple trend model. For noncore retail customers, for noncore commercial and noncore industrial, we again use end-use type models. And electric generation, we use PLEXOS production cost simulation model that Jeff will talk about.

And by electric generation, it’s really just dispatchable electric generation and large core generation. For small cogeneration we have econometric model so is for the refinery, industrial, and refinery cogenerate of electric models. And EOR [enhanced oil recovery], we have a simple trend model. For San Diego, we essentially, what we have, we have similar model for residential or commercial that we are listed here for SoCalGas. And as the wholesale customers, or particularly the sum of all customer segments demand is sort of San Diego’s wholesale demand.

And for Southwest Gas, City of Vernon, and Long Beach, we get from this respective wholesale customers their proprietary forecasts. And then we have one international wholesale customer, EcoGas, again, we have simply trend model.

Next slide, please.

In high level, I'll basically describe how we get average year demand forecast. Okay? So on the very left, we have, you know, for -- most of the market segment is showing the previous slide. We have end use forecasting model or for some of the noncore customer segments, econometric model. We basically have a forecast and average year weather design. Okay. And the major input on the line, these models are, you know, demographic driver, economic drivers. We have gas electric prices. We have carbon prices. We have customer forecast. We have appliance saturation, you know, gas appliances. And also the UECs which stands for unique energy consumption for residential market or EUI which is energy used in the sense for the commercial market segment. So there's average usage for gas appliances.

And we have, we also fit in the weather design criteria. We also include a base year weather adjusted throughput. Okay. And some other inputs.

Then once we get the results from our sort of end-use or econometric models, we do some, we call after model adjustment or post model adjustments. Okay. Our model structure is such that, you know, some of the dynamic changes that happens over time, it's not very easy to model -- to capture that in sort of our model in the left column. Okay. So we basically take the results from there and then we make some adjustment for that. So like PG&E described that for EE savings, you know, we do after model adjustments. And the EE, energy efficiency elements that we capture is exactly like PG&E described. It's committed and also additional achievable energy efficiency. You know, the goal that the Commission decides on.

Then we also model climate change. Global warming, in fact, that's also up to the model or post model adjustment. Then we have some customer migration from noncore or vice versa, we do that.

So then we come up in the final forecast which is essentially repeating the sort of average year weather design so what we get is the average year demand. And on a very high level, you know, for the forecast of residential customers in demand growth is the new housing starts is the main driver for the residential market segment. And for the commercial industrial market forecast is really the projected employment groups over time.

Next slide, please.

This -- end-use models are extremely data-intensive model. And it's partly sort of for like a inventory tracking model. It basically figures out for customers what household or commercial industrial customers energy used essentially is through the different gas appliances they have and the use of it. And two quick key steps particularly at a point in time would be in appliance stock they have and also it charts in the collection of this appliance stock whether it's space heating, water heating, clothes dryer, or cooking, for example, and whether they choose a gas or electric appliance. And also once they choose it, they're in charge of the efficiency level and they can purchase, you know, high efficiency or standard efficiency.

As the simulation steps forward from one year to next, we keep track of -- the models keep track of each year between new load added due to new meters or new customers. In addition to for existing customers, you, for example, some of their appliances become worn out and then they make a decision of new appliances for their new place, gas appliances, gas appliance or electric appliance and the associated energy efficiency for those appliances.

Now base year forecast is calibrated to base year historical weather normalized consumption. Now as you know for the long-term demand forecast, you know, weather is very hard to predict so the long-term demand forecast we basically forecast gas demand under normal weather condition. And the way we define normal is sort of an average of historical 20-year average.

And so one of the salient feature of the annual forecasting model is the calibration approach. So for the 2020 CGR, 2019 we call it the base year. So when we developed a forecast, 2020 forecast, we had historical data from 2019 and we also used the end use forecast model to develop up the forecast of 2019. And the calibration really means that we come up with the forecast for 2019, the base year, and compare that with the actual consumption. Actually, not actual consumption, take actual consumption and weather normalize it. Okay. And to the extent that weather normalized, historical consumption was higher and lower than the forecast. We basically calibrate or adjust the forecast up and down so it matches.

Okay. Next slide, please.

So for the noncore customers, as I mentioned, every year we have econometric model, models for SoCalGas refinery industrial and refinery cogent customers. The sort of exploratory variables of the econometric model of the gas and the propane prices. You can think of to get propane prices are competing input in the gas prices lower, the refinery's going to use gas and vice versa. The propane prices lower than they are going to use propane instead of gas.

For SoCalGas small cogeneration is again, well, it's driven by the gas price and the electricity price. You can think of it as the input price and the output price. So if the electricity price is very high compared to the cost of producing electricity, then they're going to use the gas.

For enhanced oil recovery, we use a simple historical trend. It could be average of last three years or five years.

Next slide, please.

So here we're talking with the post model adjustments. We talked a little a bit about the energy efficient savings and that's really PG&E described in great detail what those savings are so I'll just quickly go and move to the next one.

Weather designed to account for -- sorry, sorry, if you could go back to the previous slide. Yeah.

So I want to point out weather designed to account for global warming. In the 2020 CGR, for the first time, we've basically incorporating the fact that on average, winters are getting warmer so we have fewer and fewer HDD on average. Okay. So for the forecast period, we projected an annual HDD reduction of about four heating degree days each year for SoCalGas.

Next slide, please.

So we essentially talked about a previously, you know, our average year demand forecast. And then the second scenario or for the weather sensitive load, we have come up with a 1-in-35-year cold year demand forecast. And if you -- you can see the process as in a cold year demand, gas demand will be higher than the average year gas demand. And the incremental gas demand really depends on average year, weather design, and 1-in-35 cold year weather design and basically what the -- the average demand was associated with the average year is to HDD design and basically we have historical relationship between sensitive and between how much gas demand changes if heating degree days change by one and then for each market segment.

Okay. So this incremental cold year demand is derived by this element that we -- the bullet points we have highlighted in one, two, three, and four. And the average of demand average year is to be designed 1-in-35 cold years to be designed and demand sensitivity per HDD.

Now the, for us, the weather sensitive market segments are residential or commercial or industrial. SoCalGas's noncore commercial, these are the customers segments which we consider HDD sensitive market segments. For non-HDD sensitive market segments, cold year demands are basically the same as the average year demand.

Next slide, please.

So we also calculate peak day demand and we have basically two scenarios. One is 1-in-10 year peak day at temperature design which is 42.2 degrees Fahrenheit. And for 1-in-35 peak days in temperature design is 40.5 degrees Fahrenheit. And both of these sort of these degree Fahrenheit are based on we look at annual coldest day HDDs over the last 70 years starting in 1950 and going through

2019. Okay.

And the way I described how we come up with sort of incremental gas demand in 1-in-35 peak year. So the analogy’s similar. What we do is that we look at sort of average cold day demand which would be an average day in December and we basically look at what is the incremental gas demand for peak day in December. And the way we come up with is when the in core peak day temperature design which we talked about in bullet one and two, then we look at average year demand 1-in-35 cold year demand and then we come up with the sensitivity, you know, to peak day -- to daily demands to HDD.

Next slide, please. Next slide.

So Jeff will talk about the next couple of slides.

MR. HUANG: Okay. My name is Jeff Huang. I do the EG gas demand forecast for SoCalGas. And in late 2019, we licensed PLEXOS production cost simulation model from energy exemplar. And because CEC has a very comprehensive database, we basically download the CEC’s spring 2020 database as our reference case. And then we make changes on top of that as needed.

And for 2020 CGR, we selected and met demand case with mid-AAEE case. That’s our electricity demand for our simulation. And then we made additional changes such as we inputted the updated compliance schedules per State Water

Board and we extended the retirement date of Alamitos, Huntington Beach, Ormond Beach, and Redondo Beach.

Next slide.

And I think this is a major deviation from the CEC's forecast. For the natural gas price forecast, we did not use the CEC's forecast. We used the market price reference methodology. It is a combination of the NYMEX Futures and other long-term gas price forecasts. And at the same time, we updated where as needed and we make sure that renewable resources is 60 percent RPS goal by 2030, and we kept it at 60 percent for 2035.

And so for most of the database, we followed CEC's database and we want to be in sync with their database so that we are on the same page. And our general methodology is when we get the new database, we do a sanity check, and then we provide feedback back to CEC for any corrections so that as we move forward, all databases will be in sync.

And so another -- for CGR 2020, we do two scenarios; average year hydro scenario, and the 1-in-10 dry hydro scenario. I believe the average year hydro scenario is in the CEC database, it's based on a 15-year average. And then we select a year that meets the 1 in 10 dry hydro conditions. And for the CGR 2020, we selected hydro year 2015.

And for the next CGR, for the CGR 2022, we hope to use CEC's most recent database as of spring 2022. And again we will follow the same methodology and provide any feedback back to CEC on the data in our service territory.

And now back to Sharim for the results.

MR. CHAUDHURY: Next slide, please. Next slide.

As we mentioned earlier, for the residential market segment, new housing starts basically a significant driver for the long-term demand forecast. So this chart is from the 2020 CGR report. So in southern California, what we are observing is that new building is slowing down but their record low interest rates are expected to bring strong recovery.

And if you look at this slide, you know, it says historical sort of housing starts from 1990 on ward and it goes up to the forecast period of 2035. And as you see that in the great recession of 2008 and ’9, the housing started to decline significantly and it has picked up and with this low interest rate, we think it’s going to pick up even more.

And one of the observation is since the last 2008, 2009 if you will observe the proportion of multi-family housing starts -- is sort of proportionately more since 2010 compared to the time period before 2010. Just interesting to note. So we had a low of 20,000 2009 and for 2019, we have seen sort of 51,000, you know, it’s forecasted to be 70,000 in 2023 and 61,000 in 2035.

Next slide, please.

Here we are looking at sort of our active number of meters and meter growth. So the orange bars basically shows the meter growth and the black line basically shows number of active meters in millions on the right-hand side scale. Whereas that meter growth is on the left-hand side scale. So actual 2019 active meters for us was 5.8 million and we are seeing sort of an average annual growth. We are expecting over the forecast period of 0.6 percent.

Next slide, please.

Major legislations affecting the forecasts in the 2020 CGR. For Senate Bill 100 is for that eligible renewable energy and zero carbon resources supply 100 percent of retail sales in electricity in California by 2045. It also calls for renewable energy to supply 50 percent of the state retail electricity by 2026 and 60 percent by 2030. And Jeff has incorporated sort of these assumptions in his EG gas demand forecast.

For energy efficiency Senate Bill 350, the goal is double the cumulative energy efficiency savings by 2030. And these state energy efficiency projections we have included in our 2020 CGR forecasts.

For Assembly Bill 3232, you know, calls on state agencies by 2021 to develop plans and projections to reduce greenhouse gas emissions in California’s residential and commercial buildings to 40 percent below 1990 level by 2030.

So we have not included sort of the gas demand reduction associated with greenhouse gas reduction in the 2020 CGR. Going forward we are -- in the 2022 year we are thinking about including some scenarios. PG&E had some scenarios in the 2020 CGR and they talked about it briefly and we'll have some scenarios most likely in the 2020 CGR. We have not defined these scenarios yet.

Next slide. Next slide, please.

So this is sort of the summary from the 2020 CGR gas demand forecast sort of overall in the high level by residential, core nonresidential, noncore non-EG, and electric generation, and wholesale customer group. So the total order expected to fall between 2019 and 2035 declining an average of 0.9 percent per year. And for comprehensive purposes, they sort of -- the rate of decline is higher if we compare it with the 2018 CGR and also with the prior 2016 CGR. And primarily, the reduction is from energy efficiency program savings offsetting, you know, the meter growth and the employment growth.

Next slide, please.

And here basically we talk about what are the change in demand by customer segments. For residential, gas demand declines about 1 percent between 2020 and 2035. And again declining use for meter more than offsets the meter growth.

And since 2021m weather-normalized residential use for active meter has been dropping by 0.6 percent per year. Commercial gas demand is expected to fall by an average of 1.1 percent per year. Industrial load is expected to decline by 0.6 percent from 2020 to 2035.

Next slide, please.

Wholesale, excluding SDG&E is expected to shrink slightly between these forecast periods. San Diego's gas demand is forecasted to decrease an average of 0.6 percent per year. NGV load are expected to grow by 1.4 percent per year and it's largely due to low carbon government incentives and low natural gas prices relative to gasoline and diesel. And carbon offsetting renewable natural gas already fuels about 80 percent of our territory natural gas vehicle load. Enhanced oil recovery steaming demand is forecasted to remain steady, you know, throughout the forecast period.

Next slide, please.

You're not talking about it, Jeff? In the EG demand forecast? Are you in it?

MR. HUANG: The EG demand forecast is expected to decrease over time. And, I mean, it's largely due to the increase in renewables. And it's -- the renewable is mostly displacing the natural gas. And then for the dry hyrdro scenario, we notice that the dry hyrdo has lesser impact than prior CGRs and we think that's largely due to the increase in renewables. We have RPS reaching 60 percent by 2030 so there's a significant amount of renewable generation to displace the hyrdo.

Okay. Back to you, Sharim.

MR. CHAUDHURY: Next slide, please.

I guess we are done.

MS. RAITT: Thank you, Sharim.

Commissioners, we have a little time for discussion if you have some questions or comments for Jeff and Sharim.

COMMISSIONER GUNDA: Yeah. So thank you, Jeff and Sharim and the PG&E team for all the presentations. I think it's really, really helpful to see how you're considering various aspects moving forward.

I know there's a bunch of questions that came through Q&A so I'm going to ask one question and then see if Commissioner McAllister has any and then go to Q&A and then we can come back if there is time.

So the high level, Sharim, I think specifically you mentioned about climate change impacts being talked through in terms of adjustments to the heating degree days.

MR. CHAUDHURY: Uh-huh.

COMMISSIONER GUNDA: Just wanted to ask what the PG&E team and you, maybe Andrew might want to comment on this, one is kind of rationale behind decreasing by 4 heating degree days, reducing by 4 heating degree days. And what are PG&E doing similar to capture climate change impacts?

MR. CHAUDHURY: Okay. So this is Sharim, let me just try to explain what is the rationale for decreasing heating degree days by 4. So our average heating degree days per average year, we basically calculate over a 20-year period. And we have an actual historical data, so we have calculated sort of 20 numbers of 20-year average heating degree days based on going into the future. Okay.

So we have this 20 data elements and basically based on that, we basically looked at the trend, okay, how the heating degree days over this 20-year average heating degree days has changed over this 20 of the observation points through regression analysis, and we found out that it's about 4 degrees -- 4 heating degree days.

COMMISSIONER GUNDA: Thank you, Sharim.

Maybe Andrew or Kurtis has -- wants to share anything from PG&E and I just have a quick follow up.

Andrew, you're muted if you're speaking.

MR. KLINGLER: There we go. Yes, on the regression side, we have looked at the California climate adaptation forecast and so we've done a very simple linear interpolation of that going out to about 2040. And so we have a coefficient that increases the number of -- excuse me, decreases the number of HDD over time. And I would have to look up the exact amount, but it's about .6 per -- .6 HDD per year.

COMMISSIONER GUNDA: Right. So I think just a follow up to both of you. So one of the thing on the electricity demand side, at least given the level of the concerns we've had the last couple of years, it has been this consideration that, you know, history's not a good indicator of the future in terms of the uncertainty and the volatility that we might see in the fluctuations.

Has there been thinking about how to capture future uncertainties and volatility around temperature, drought, and so on? Just your high-level talks on how that would helpful.

MR. KLINGLER: I'll go first, if that's okay. What we have really started moving toward internally and probably would prefer to do externally also is to move towards a scenario analysis based approach where we instead of trying to estimate something like statistical variation or we would specify actual possible scenarios that might play out. And that would include both climate scenarios and policy scenarios because obviously as we move forward, that's a big driver.

MR. CHAUDHURY: Commissioner, you brought up a good point. So what happened is that for -- due to climate change, the average heating degree day per year is declining. But as you pointed out, the volatility, okay, it could be become more intense. So what we are finding out from some work we have done is that even though the average year throughput is going down, peak day demand not naturally is coming down as much.

COMMISSIONER GUNDA: Got it.

MR. CHAUDHURY: Okay.

COMMISSIONER GUNDA: Thank you, Sharim. Thank you so much.

I'll pass it on to Commissioner McAllister and then we'll go to Q&A.

COMMISSIONER MCALLISTER: Thank you, Commissioner Gunda. So you read my mind kind of on that, you know, future, you know, sort of expanding envelope of possibilities going out and how we're going to capture that is, you know, the past is not a good predictor. So that's an interesting ongoing discussion.

My question just has to do with the 3232 world, both PG&E and SoCal. I was happy to see you mention the 3232 report and those scenarios are pretty stark in terms of what we told the legislature would need to take place in order to get the building sector to 40 percent below 1990 level. And there's, you know, in order to do that the takeaway is pretty much massive fuel substitution from gas end uses to electric, certainly in a residential sector where it's most prevalent.

And I guess I'm wondering a couple of things about that. You know, one did you do true, I think SoCalGas did not, I had to step away a little bit so I didn't hear fully what PG&E is doing on that. But, you know, I guess I would just ask if you have done and encourage you to do, if not, some full sort of 3232 scenarios just to see where that leads. You know, maybe it's a bookend, maybe it's not, but I think that would be helpful how have you contemplated those scenarios in each of your respective forecasts?

MR. CHAUDHURY: Andrew, do you want to go first? Or I can go.

MR. KLINGLER: You can go ahead, if you like.

MR. CHAUDHURY: Okay.

MR. KLINGLER: I have a few people on the team. Yeah.

MR. CHAUDHURY: Yeah. Commissioner McAllister, we are looking into the scenarios. Okay. I mean, the way we particularly, we do it is that as we discussed, you know, in the California Gas Report, we pretty much had in terms of truthful forecast we put for, you know, two scenarios. One is the average year and one is a cold year dry hydro. And it seems like when this decarbonization goes, we probably need to have additional scenarios including maybe some bookends like you mentioned. Okay.

The reason is that, you know, our demand forecast, like 1-in-10 year, 1-in-10 cold year demand forecast and the peak day demand forecast that used for our transmission planning purposes, right. So we have started talking internally, we're not in a position to basically say much. But I feel like we probably need to have additional scenarios in the California Gas Report.

And why I said that is that sometimes we are ask to pick a point estimate, what do you think is the best forecast, right. And that point estimate gets very difficult, you know, in the future, right, when this decarbonization scenario what is likely versus goal. Because as you know for our cost allocation and rate design, we use sort of, we come up with the rate is revenue to curve and divided by average year throughput. And average year too could be significantly different depending on the level of decarbonization.

And likewise, you know, we are supposed to have a reliable transmission system, okay. And for slack capacity on our transmission system, we look at 1-in-10 cold year average day throughput. And this issue has come up in the gas OIR sort of track one issue.

So, I mean, we probably need to put forth more scenarios but the end of the day we need to figure out if somebody asks us to give a point estimate, what do we point to.

COMMISSIONER MCALLISTER: Thank you for that. I would agree, some additional scenario work and also the crosswalk over with the electric side, right, just because

SB100. Not every, you know, sort of unit of energy consumption that migrates from a gas end use to an electric end use is going to actually imply the same amount of carbon on the electric side, right, depending on the scenario.

So I think there's a pretty nuance sort of co-scenario development maybe that ought to take place here to capture fuel substitution. And, I'm sorry, I got in front of you, Andrew, so go ahead.

MR. KLINGLER: No, that's fine. I'm -- yeah, we similarly we have, we're in a world where we're working with point forecasts and not have done a lot of super sophisticated work beyond that. We do have the electrification forecast that you see here and that we update regularly. That is actually set up in a way that's consistent between the gas and electric side. So there is an estimation exactly of how that energy is being traded off.

The accuracy of that kind of thing, of course, depends heavily on, I mean, it's not going to be super precise and it also depends itself on assumptions about policies that are behind the way things play out.

COMMISSIONER MCALLISTER: Okay, yeah, great. Thanks very much. I appreciate those answers.

We have some really good questions in the Q&A so I want to ask to pass to the moderator for Q&A. So I think that's Jennifer Campagna?

MS. CAMPAGNA: Yes, it is. Thank you, Commissioner.

Okay, so to start off, Tom Beach has a two-part question and this is for PG&E.

Is the PG&E electric generation throughput forecast consistent with the adopted CPUC 2030 GHG emissions of 46 MMP in the IEPR reference system portfolio?

Part two, if the 2030 GHG goal is reduced to 38 MMP, how much would the EG forecast decrease?

And I'll turn it over to anyone in PG&E who would like to answer.

MS. RAITT: Andrew, I think you're muted.

MR. KOLNOWSKI: I think Todd Peterson has a response to these. That's probably double muted. I can respond to this myself.

So two-part question. The first is what assumption was used in the CGR? And the second, how would EG change using that more stringent GHG reduction target?

So the first one, CGR does use the preferred -- or the reference system plan 46 million tons. I believe that was a compilation of February of 2020 that's cited in the CGR.

The second one, that GHG target -- or using the more stringent GHG goal, that's a place where we're definitely looking to conduct additional analysis particularly around updated portfolios that may target that. I know that the

CPUC is proposing a preferred system plan looking at 38 MMT. So I would expect this to be a source of frequent discussion in the upcoming months.

MS. CAMPAGNA: Thank you. Is there anyone else from PG&E? Okay, great.

The next question is for both PG&E and SoCalGas and it is from Mike Florio. If overall residential and commercial average gas demand are trending downward, is there any reason to expect peak demand for these customers to follow a different trend?

And we can start with if PG&E would like to do the first response followed by SoCalGas.

MR. PETERSON: Hi, this is Todd Peterson with PG&E.

The way to think about what's happening on the demand side as observed demand over long-term declining, I think a good way to take a look at this is that the forecast that we have in the 2020 CalGas Report. There was one perspective of looking at the abnormal peak day demand which are -- is an extreme condition forecast. And that is that they 1-in-90 cold temperature event to ensure that our PG&E system can meet that peak demand for core customers.

So that's in the CalGas Report, you can see that. There is over the three-year period that we are forecasting for abnormal peak day, or APD, there is a slight uptick in core demand.

Secondly, there is also a summer and winter peak day forecast. And in general, those demands are flat to declining in both those periods of winter and summer.

I think that's a good area to start with and I think that there's an area to do more study in how demand would be changing as the system changes with more renewables on system. We see electrification growing. There is still a lot of uncertainty around this, an unknowing. So the scenario analysis should help us understand that better.

MR. CHAUDHURY: Okay. Think about -- I think if the ever reached for residential market segment toward the average usage to go down, peak demand might not change much, you know. Think about for residential market segment, gas big demand happens either in December or January.

Think of what -- we can think of a situation that they could be cloudy or rainy where we may not have, you know, solar providing sort of the electricity so we may have to meet the residential sort of heating demand. We may have to fire up the gas, you know, stand by peaker unit, for example. So it's not a one-to-one reduction, you know, for if the average demand goes down, peak demand might not necessarily go down.

MS. CAMPAGNA: Okay. Thank you. Appreciate it.

Okay, so the -- looks like the last open question we have is from Katie Elder. And the question is for Sharim.

Sharim, are you seeing the 42.5 degree increase as your 70 years rolls forward?

MR. CHAUDHURY: You know, for peak days, you know, weather design, we basically have not rolled in 70 years, we just, you know, the oldest data we captured in 1950 and basically additional cold days the year progress, we basically add to it.

Now what happens that we are picking up the coldest day for each of those 70 years. And if we add one or two more years, it’s really is not impacted the tail end of the distribution as much, as I recall from last year. So I think it’s not changing much. That would be my answer now but I can look into that.

MS. CAMPAGNA: Okay. Thank you, Sharim.

So we actually have another -- one more question, a follow-up question from Mike Florio. I understand that average and peak may decline at different rates, but is there any logical reason why peak would increase when the average is declining?

MR. CHAUDHURY: Yeah. For SoCalGas, we have not looked at the essential peak demand in particular. Maybe we should look at that. We basically look at sort of system peak. I couldn’t answer the question now, okay, but the idea is that if -- because of, if in the future, for example, someone is heating demand is transferred to, based on say electric heat pump and things like that. And if we do have, for example, a cloudy day, I don't know if the peak demand could go up or not. But it's, my first guess is Mike is unlikely.

MS. CAMPAGNA: Okay. Thank you. Is there any follow up from Todd or anyone at PG&E on this question?

MR. PETERSON: Hi, it's Todd Peterson from PG&E. We don't have the right experts here to really uncover this a little bit more. It's something that we would need to get back to you.

MS. CAMPAGNA: Okay. Thank you, everyone.

That is it on our open Q&A on our Zoom session.

Heather, I will turn it back to you. Thank you.

MS. RAITT: Great, thank you. And so, thank you, Jennifer, for leading us through that.

Commissioners, if you didn't any have -- or if you have any final comments or questions for the utilities; otherwise, we will move on to public comment.

COMMISSIONER MCALLISTER: Thank you. Thank you very much.

MR. RAITT: Commissioner Gunda, we can't hear you.

COMMISSIONER GUNDA: Thank you, double mute.

Thank you so much again, Andrew, Amy, Todd, and Kurtis, Sharim, and Jeff for being here. I mean, I know the forecasting in the modeling part is such a grueling task. So it's definitely something that is self-selected by people who like to do those things. So I really appreciate all the work and time to be here.

And I think my way of comment is, you know, as we move forward, I think what Andrew noted this and Sharim, the importance of looking through scenarios and then having adequate participation of possible futures to guide policy. It is important.

I think it kind of goes through both, you know, electrification and the end use policy scenarios, the weather scenarios. But also looking at it from a temporal and geographical distribution as well. So I look to your continued efforts in improving the forecast and working at CEC to improve analytics as well. Perhaps as a state, we can have a good set of forecast data to make decisions. So thank you all so much for being here and helping us through this conversation.

MS. RAITT: Super. All right, Commissioner, we'll go on to public comment and thank you again.

Right now we have RoseMary Avalos to lead us to public comment. Go ahead, RoseMary.

MS. AVALOS: Thank you, Heather.

Commenters, please allow one person per organization make a comment and comments are limited to three persons -- three minutes per speaker.

And I'll move on to those on Zoom. I see that Frank Seres has his hand raised.

Frank, your line is open. You may need to open on your end. Frank, you may need to open on your end.

Okay. I'll move on to Mike Florio. Please state your first and last name and spell that, as well as if you have an affiliation, please state your affiliation.

Go ahead and speak. You may need to unmute on your end. Go ahead and speak, Mike.

MR. FLORIO: Okay, I'm trying to.

MS. AVALOS: We can hear you. We can hear you.

MR. FLORIO: Okay. Yes, Mike Florio, F-L-O-R-I-O. I'm an independent consultant. And I just wanted to raise a question about the rate escalation assumption for transportation rates for gas. A 2.3 percent seems remarkably low to me. PG&E's current rate base is looking at a 18 percent increase in the gas revenue requirement with further attrition issue that increases every year to follow.

So that's not rounding error from 2.3 percent. That's quite substantial and I think SoCalGas's last rate increase is well more than that small percentage as well. So I think you would want to take a close look at those assumptions because it certainly seems like that rate of increase, if anything, is accelerating.

That's all I have.

MS. AVALOS: Okay. Thank you, Mike.

And I think Frank Seres, your mic is open.

Okay. Seeing that there are no hands raised on Zoom, now I'll move on to the phone lines. And a reminder for those on the phone to dial star 9 to raise your hand and star 6 to unmute. Okay. So let's give a second for those on the phone to if you want to raise your hand.

Okay. Seeing that there are no raised hands, that completes public comment.

I turn now to Commissioner McAllister.

COMMISSIONER MCALLISTER: Thank you, RoseMary.

So, Heather, correct me if I'm wrong, that's it for the day if we have no more questions from the dais or and there are no more panels. So.

MS. RAITT: That's right, you're done.

COMMISSIONER MCALLISTER: Great. Okay. I guess I would just say thank you to Commissioner Gunda for your stewardship of this and your leadership and just, you know, your deep knowledge of this really helps the conversation keep grounded and bring in new information in a really, really good way. So I really appreciate all your guidance on this.

And I would just say, you know, okay, with the caveat that, yes, it's a bunch of gas nerds in the room here. This is big stuff, actually. The way we're really modernizing the gas side of the house to match up with the electric side and in all the ways that Commissioner Gunda mentioned. And so I think that increased regularity and temporal appreciation, and the interlinkages, you know, that we put in place across the electric and gas forecast increasingly, and work with the utilities to do that as well on their side. And then really match those up and work through all these issues in an open way is real critical.

It’s just, it’s -- that process can really make some better product and it’s essential to getting it right and rolling with reality over time, so I’m really appreciative of this process and the presentations here today both from staff and from utilities.

With that, I think we’re in a good place and building those communication bridges to really be continually drilling on the issues as they come up and then move forward to constructive forecasts itself.

So I pop back to you, Commissioner Gunda.

COMMISSIONER GUNDA: Yeah, thank you, Commissioner McAllister. I couldn’t say that better. I know I just want to thank the staff. You know, we’ve been going so many different directions over the last especially 18 months. Some heavy lifts from SB 100, AB3232, the building code and all of that has direct implications on the future of gas and how we think about the infrastructure and what we evolved the infrastructure for.

So I think this was an important conversation, as you stated, and I just want to thank Melissa, Jennifer, A.J., Ryan today as well as Jason, Peter, all the intent gas team. Thank you so much for all the incredible work that you're trying to do in envisioning the gas analysis at CEC.

With that, I just -- I want to thank all the stakeholders for being here and helping us, keep this conversation grounded and offering perspective to challenges us, but also agree on elements. This is, as Commissioner McAllister said, process is key to see these work. Thank you for being here in helping us move the conversation forward.

Thank you so much and with that I will pass to Heather to have the last word.

MS. RAITT: All right. And our last word is to say written comments are welcome and they're due on September 13. And we have another workshop tomorrow so come join us for a workshop on renewable natural gas. And that's it. Thank you.

COMMISSIONER MCALLISTER: Thank you everyone. Thank you, Heather.

(Thereupon, the Hearing was adjourned at 2:25 p.m.

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CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 7th day of October, 2021.

Elise Hicks

ELISE HICKS, IAPRT CERT**2176

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IN WITNESS WHEREOF, I have hereunto set my hand this 7th day of October, 2021.

Jill Jacoby

Jill Jacoby
Certified Transcriber
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