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CALIFORNIA ENERGY COMMISSION
IEPR COMMISSIONER WORKSHOP

In the Matter of:	Docket No. 19-IEPR-08
	IEPR COMMISSIONER WORKSHOP
2019 Integrated Energy Policy Report	

IEPR COMMISSIONER WORKSHOP ON
PRELIMINARY NATURAL GAS PRICE FORECAST AND OUTLOOK

CALIFORNIA ENERGY COMMISSION

THE WARREN-ALQUIST STATE ENERGY BUILDING

ART ROSENFELD HEARING ROOM - FIRST FLOOR

1516 NINTH STREET

SACRAMENTO, CALIFORNIA 95814

MONDAY, APRIL 22, 2019

10:00 A.M.

Reported By:
Peter Petty

APPEARANCES

COMMISSIONERS AND ADVISERS:

CALIFORNIA ENERGY COMMISSION:

Janea A. Scott, Vice Chair, Lead Commissioner for 2019 IEPR, California Energy Commission

Karen Douglas, Commissioner, California Energy Commission

Andrew McAllister, Commissioner, California Energy Commission

OTHER PRESENTERS:

Jonathan Bromson, Attorney, California Public Utilities Commission

STAFF:

Heather Raitt, IEPR Program Manager

Jennifer Campagna

Anthony Dixon

Robert Gulliksen

Angela Tanghetti

PUBLIC SPEAKERS

(None.)

I N D E X

I N D E X (Cont.)

P R O C E E D I N G S

APRIL 22, 2019 10:02 a.m.

MS. RAITT: This is the IEPR Commissioner Workshop on the Preliminary Natural Gas Price Forecast and Outlook. I'm Heather Raitt.

I'll quickly go over housekeeping items.

If there's an emergency and we need to evacuate the building, please follow staff outside the building to Roosevelt Park across the street.

We are being recorded and we will have a written transcript in about a month. And we're being broadcast over WebEx, and we will post a recording of the workshop in about a week or so.

We will have an opportunity for public comments at the end of the workshop. Folks can go to the center podium to make remarks, and we'll limit it to three minutes per person.

For WebEx participants, please just use your raise-your-hand feature and we will open up your line at the appropriate time at the end of the day.

The materials of the meeting are posted and available at the entrance of the hearing room, and written comments are welcome and due on May 6th.

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

COMMISSIONER McALLISTER: Thanks, Heather. This is Andrew McAllister, lead on efficiency and overseeing the forecast this year. Not a whole lot to say. This is sort of the first incursion into the natural gas arena, this IEPR cycle.

Just wanted to point out that sort of the context I think is a richer context this year maybe than previous IEPRs, a lot of talk about natural gas and what its future is. And so we're not really to get into that today.

This is sort of the traditional forecast pathway that we're starting here, but I think inevitably over the course of the forecast period, we're going to talk about different scenarios which I think is a broader conversation this year than it has been the past.

And so I'm really actually looking forward to that process and bringing in stakeholders. And I think there will be more interest than sort of historically maybe. It won't be the technical sort of market participants only. I will also be a little bit more advocacy and probably some stronger opinions about this down the road.

So I think that's a conversation we do have to have. And we're sort of kicking it off in general terms today. But this really a foundational workshop, and it's all staff from the Energy Commission and from the Public

Utilities Commission that we thank for being here and presenting today. And looking forward to hearing about the pilots that they've got going on.

So with that, I'll hand it to Lead Commissioner Scott.

VICE CHAIR SCOTT: Good morning. Thank you. I'm Commissioner Scott. I'm the lead for the 2019 Integrated Energy Policy Report this year and I will mostly just echo what you heard Commissioner McAllister say.

This is our Preliminary Natural Gas Price Forecast and Outlook. And again, we have maybe a little bit broader of a context to be looking at this and thinking about this this year. So we warmly welcome engaged participation, and I'm looking forward to today's workshop.

MS. RAITT: Great. Our first presentation is from Jennifer Campagna from the Energy Commission.

MS. CAMPAGNA: Good morning, Commissioners. My name is Jennifer Campagna of the Natural Gas Unit in the Energy Assessments Division.

Today I will be providing an overview of the proposed topics for the 2019 Natural Gas and Market Trends and Outlook Report.

Just a brief background, under statute, the Energy Commission is required to conduct a natural gas assessment in support of the IEPR. The Natural Gas Outlook

Report supports this mandate. It's a technical supporting document for the IEPR that assesses natural gas trends and issues on a national and state level and provides natural gas price projections for the next several years. The major points from this report will be summarized in a chapter for the 2019 IEPR, along with any policy recommendations.

Just a brief overview of the topics that we are proposing for the Natural Gas Outlook. I will provide more detail on these topics in upcoming slides.

As mentioned, the report will provide the annual natural gas price projections out to 2030. It will also provide an overview of the production cost modeling results. It will have an update on natural gas trends on both a national level and for California and an update on how we're meeting the requirements of Assembly Bill 1257. Again, I'll provide more information on that in a later slide.

The main topic that we do cover and we will cover in this Natural Gas Outlook Report is the natural gas price projections. The Energy Commission uses the North American Market Gas-trade model, also known as NAMGas, to produce natural gas price projections for both the United States and California.

A chapter of the Outlook Report will describe the inputs and assumptions used in the model and will provide the findings for the high, mid and low demand 2019 IEPR common cases and the associated prices with those cases.

Anthony Dixon from the natural gas team will be providing more detail on the natural gas price projections later this morning, and he'll be providing the preliminary natural gas price projections today. The Outlook Report that will be adopted later this year will contain the revised price projections.

Staff from our production cost modeling team use the PLEXOS model to forecast natural gas demand for power generation in the WECC region and the impacts to California. They consider various inputs and assumptions such as power plant retirements and additions and clean energy policies.

They also provide GHG emissions projections. The same chapter that covers the NAMGas findings will include a description of the PLEXOS findings.

And today Angela Tanghetti will discuss the inputs and assumptions and early results from the production cost modeling. And the Outlook Report that will be adopted later this year will provide revised projections for natural gas demand for the WECC region, including California.

In the report, we will have a chapter that describes what is happening U.S.-wide with regards to natural gas supply, demand and infrastructure. We will explore trends such as the increased natural gas production and growing supply U.S.-wide, liquefied natural gas exports, natural gas exports to Mexico, and possible impacts to California.

In terms of demand, one of the trends we will be looking at is the switching from coal to natural gas for power generation. And we will look at demand from other sectors, not just power generation.

In terms of infrastructure, we will examine new pipelines or changes in the infrastructure.

So California, we will get into more detail. We will look at any impacts to California from U.S.-wide trends. We will look at clean energy policies and the impact on natural gas use, for example, S.B. 100 and the trend of electrification of homes.

We will look at demand for power generation and in-state production versus imports. We will provide an update on renewable natural gas.

Jonathan Bromson of the CPUC is here today. We will be coordinating with them on this issue. And he will be providing more details on their RNG program and their dairy pilot projects and related progress in this area.

As for infrastructure, we will be looking at the aging pipelines and storage facilities and their expected life span. We will also look at maintenance and safety issues.

As for storage, we will briefly discuss Aliso Canyon and the OII, but this will be a standalone chapter in the IEPR, and a separate workshop will be held on this issue on May 23rd in Southern California.

We will provide a status update on other storage facilities throughout California. And finally we'll have an update on the DOGGR rules that were adopted in 2018 with relation to well permits.

We will provide an update also on Assembly Bill 1257, which I mentioned previously. That bill was passed in 2013 and required that the Energy Commission produce a report on the benefits of natural gas every four years.

A report is due this year. But since the bill has been rescinded and the last report will be in 2023, we will actually be covering this requirement as part of the Natural Gas Outlook, especially given that with the requirements of Senate Bill 100 and the declining role of natural gas for power generation in California, we will be mostly discussing any updates on natural gas, methane emissions studies, and we will examine the Research and Development Division's efforts under the decarbonization contract and provide a status update on the EDF studies.

So as for next steps, after this workshop, we will be reviewing and considering public comments, which are due May 6th.

Staff will be running the NAMGas model and producing revised natural gas price projections later this year using the NAMGas model.

We will be writing the report in the coming months, and we will hold another workshop in the September-October 2019 time frame, where we will present the revised natural gas price projections as well as the revised findings from the PLEXOS model.

And finally at that workshop we will be presenting the draft Natural Gas Outlook Report.

With that, I conclude my presentation. Again, I will just reiterate, written comments are due May 6th. I'm happy to try and answer any of your questions.

Thank you very much.

COMMISSIONER McALLISTER: Thanks very much. I don't have any questions at this juncture, but I'm sure we both will.

So thanks.

MS. CAMPAGNA: Thank you.

MS. RAITT: Thanks. So next is Anthony Dixon, also from the Energy Commission.

MR. DIXON: Good morning, everyone. So I am here to present for the North American Market Gas-trade model, NAMGas, the preliminary results from our work this year.

First, I'll go over a little bit about it. We're producing our IEPR common cases. The demand -- this produces also not just price but also produces on a national level the demand/supply flows, prices and also shows us annual trends for natural gas throughout North America.

So a little background on the model. It's built on the MarketBuilder platform. It's an economic general equilibrium model. It's been well vetted. We've done a lot of research, and we continue to do research to make sure this is still the best model to be using. And for what we do, this is the best fit for what we do.

We always reset our assumptions every year to incorporate any of the IEPR common cases.

We also update all our pipeline capacities to make sure they're good, make sure any new construction is coming online because this is a 30-year forecast.

Also, this year -- that was something we haven't done in a few years -- we updated all our resources. We updated the costs, the proved and the potential resources, because the United States is producing a lot of gas. We're finding new ways of doing it at a much lower cost than we have ever before.

So we went through and did a lot of research using the Potential Gas Committee reserves, looking through oil and gas journals and things like that to really get our prices much more accurate compared to what they have been in the past.

So a little more about the model. It basically connects supply basins through pipelines to demand centers and gives us our prices and flows at all those different centers.

The model being generated does all 30 years across all time periods and all modeling points simultaneously. It does all these calculations at once. I'm glad I don't have to do that on paper because that would be a lot of work.

So, as you can see, this is one state of the 48 states -- Canada, North America -- just to kind of show the complexity of what's going on and what we have to trace throughout this model.

So we developed three cases to go along with the IEPR: the high demand, low price, the mid demand and low price, and we're also exploring some sensitivity cases. The two we're kind of working on and still having issues -- because trying to work these issues out on an annual model is difficult because of the constraints in Southern California. We're trying to work and see how we can model those prices, and if that constraint continues, what the prices will be if something like that continues.

Once again, on an annual model it's difficult to do.

And also, at your suggestion, Commissioner McAllister, we're also looking at the decarbonization, the less use of natural gas in buildings in California and how that declining will affect prices and things like that.

So we're looking at it. Unfortunately, on an annual model, some things kind of average out, it's a little difficult to do. But that's one reason we're working on developing a monthly model so we can get more granularity and really look at these much better than an annual model can.

COMMISSIONER McALLISTER: Let's see, could you sort of -- so we have this price issue in Southern California.

How does your model incorporate those market fluctuations? It doesn't have any explanatory power, right, over those kinds of things. But how do you use that information?

MR. DIXON: Well, what I do and what we do is we back-cast a couple years. So our model, we actually start in 2017 and we try and calibrate the model to produce and mimic what really happened in those years. And this is one of the issues we're having, we're seeing, because 2018 was such a crazy year with the Southern California issues, also the fact that we have complete price collapses in West Texas because there's so much associated gas that they can't get out.

We have Western Canada -- and these are places that supply gas to us. So we're seeing these super low prices in supply basins, but yet we're having extremely high prices in Southern California.

And, once again, on an annual model, it can -- if you have two months of really high prices, it can throw that whole annual average out. And so that's the issue we're looking at -- it has pipelines so we can constrain the pipelines, constrain flows and we we're seeing those are the price differences.

So it's just -- once again, it's -- yeah.

COMMISSIONER McALLISTER: Yeah, okay. So it's really kind of -- trying to get your head around what's happening with different runs and scenarios.

MR. DIXON: Yeah. And that's why I'm doing as many sensitivity cases as we can. We've upgraded our computer system. We have a lot better computer power now. It's not taking us as long to turn our results around.

So we're doing a lot of different things to see what happens, even if it does something crazy, at least we're looking at it, we're looking at all -- we cut this pipeline off, we add pipelines, we change supplies. We're looking at all those things.

COMMISSIONER McALLISTER: Great. Thanks.

MR. DIXON: My pleasure.

VICE CHAIR SCOTT: To that point, I think it might be worthwhile when presenting the final in September or October or in the way that we write up the report to kind of make the difference between -- to really differentiate between, okay, here's kind of what's happening on a month-to-month basis and -- but because it's this longer span, this is why you don't see it across the span. And just make that really clear so that when people are reading, they can kind of understand the difference between what was happening last summer versus what we see over 10 years.

MR. DIXON: That would be my pleasure.

So for a model, we have a couple different imports. Basically it's residential, commercial, industrial, power -- and natural gas for transportation use.

These are all produced by a model called our Small "m" model. And Robert Gulliksen is going to be presenting on that a little later, because we've updated it as well this year.

We also -- our model has elasticities. We updated them this year. There was a new study by Hausman and Kellogg about new elasticities for the prices, so this is the first update we've done in a few years on that.

Probably the biggest thing that really drives our model is the natural gas supply. And as this graph shows, over the time from 2007 to '15 to now our 2019 cases, how much more gas we're producing at even lower and lower costs.

This is technology, just learning how to do things better.

And a little more about our natural gas supplies because we did a lot of work on updating these this year. As you can see from this, how much gas we're able to get. This is from the Potential Gas Committee.

So our future supplies have reached over 3000 TCF in 2016. This is just historically high. We're producing more gas then we've ever produced before yet our reserves keep increasing, our proved reserves, our potential reserves are just increasing like crazy.

And another thing to show, another reason costs are coming way down is a lot of the gas being produced is associated gas. They're not even looking for the natural gas. They're looking for oil, they're looking for propane, ethane, butane. And natural gas is basically a byproduct.

Waha, Texas is a perfect example where they're having negative prices, 40 cent prices. They can't get the gas out of there. They're having historic amounts of flaring of natural gas. Hopefully, by the end of this year, they're supposed to have some more take-away capacity to come back on so they can get the gas out.

There's projects where they're going to build gas from the Permian Basin to the Gulf Coast to get out for LNG use.

And that's another issue, is we have Mexico with a new president. They've said they're going to divest from natural gas and put money into their diesel fleet. So that kind of threw -- a whole bunch of pipeline projects basically are now in limbo.

If you go on like Point Logic, who is one of our big sources, a lot of these natural gas projects for pipelines coming out of the U.S. going into Mexico have now been canceled or delayed or postponed until future things.

So that was a lot of take-away gas that was coming off, which in supply perspective that helps the U.S. because that means we have more gas for us. We're not going to be sending it to Mexico, which will help keep gas prices low.

So this is a little more on the reserves. We break it down to potential and proved. Proved is what we know is in the ground, what's already coming out of the ground. Potential is we might have to drill a little bit more, do a little research.

And so we break our potential resources into three little categories. There's a growth in known undeveloped potential and you have to find -- it's just basically how much more money and how much more resources are needed to find these reserves, and the certainty of how much reserves there is decreasing.

COMMISSIONER McALLISTER: Hey, Anthony, can I ask a quick question?

MR. DIXON: Yes, of course.

COMMISSIONER McALLISTER: So obviously this associated gas, venting, clearly a problem --

MR. DIXON: Yes.

COMMISSIONER McALLISTER: -- flaring, you know, still a problem, capturing expensive, you know, in the middle of nowhere perhaps.

I guess, are there any statutory or regulatory guidance? Is there any guidance about what should be done or what must be done with that associated gas? I mean it would have to be at the federal level, obviously.

MR. DIXON: Yes, it at the federal level, which right now is very pro, you know, “go for it” type of issue.

COMMISSIONER McALLISTER: Are there any legacy regulations that they have to comply with still?

MR. DIXON: There are but they're more -- it's more left up to the states on an individual basis. So you have like Colorado which has high -- and they're coming out more and more stringent requirements of what you can flare and how much you can flare and when you can flare.

Venting is pretty much done with -- you don't just release the gas. You have to at least burn it so it's a little cleaner, I guess.

COMMISSIONER McALLISTER: Is that a state or is that a federal requirement?

MR. DIXON: There is a federal requirement. I'm not sure exactly what the level is on that. But like I said, most states are going further. But unfortunately the two biggest states that produce the most -- North Dakota (the Bakken) and then Texas. It's just -- they're looking for the oil. They don't care about the gas and they're not too worried I guess about the environmental impacts, unfortunately.

COMMISSIONER McALLISTER: Well, you think they're flaring at least?

MR. DIXON: Oh, they are flaring. There's record amounts of flaring.

COMMISSIONER McALLISTER: Yeah, okay. So as far as you know, they do take pains not to vent.

MR. DIXON: Yeah, they at least try not to vent -- just to vent it out. But they at least try and flare it.

COMMISSIONER McALLISTER: Okay. Great.

MR. DIXON: Yeah, yeah. It's slow death over fast. Yeah.

COMMISSIONER McALLISTER: Thanks.

MR. DIXON: So when we were developing these new cost curves and things for our supply, a lot of the cost -- you know, the cost of actually drilling, how far you have to drill, how large these drillings are going, and also the production of liquid to gas ratios. These all account for the cost and how much it costs to get the gas out of the ground and on to market.

This is a nice graph kind of showing how the prices increase. You have a very -- zone of abundance where there's a lot of gas very cheap and as you start depleting it, your costs will increase exponentially.

So for our common cases, some of our assumptions -- this is in the mid demand case. These -- excuse me. These numbers are kind of the starting points for our model. These are not the actual output from the model. Our model takes these inputs and then uses the elasticities and it will change them.

So initially in our model, we have 27.5 trillion cubic feet of natural gas demanded in the United States in

2018. These are based on EIA estimates. Power Gen accounted for 9.3 TCF of that.

For 2020 and 2030, you can see it's increasing, albeit much lower than it had in the past.

Our proved reserves are from 438 trillion cubic feet. This is from December 2018. And as you can see from last -- in 2017, there were 324 trillion cubic feet, so you can see the expansion. This is proved. This is what we know we can get out of the ground. This is high certainty of gas we can get out. And even the potential resources are increasing.

We continue to use the 65 gigawatts of coal being converted to gas for our mid case.

And we've also done our due diligence and return some of these income tax rates and return on equity and investment parameters on resources and pipelines.

Backup technology is -- well, we're not using that right now because it's at $15. It's basically if gas got to a $15 price, it's some new technology that would take over, whether it be new development gas or just methane hydrates or some just new technology that would take over if gas got that high because people would want to try and find something cheaper.

Some more of our assumptions for our three cases and how we break them up.

Mid demand case, we have a 1.9 percent GDP growth rate. This is for the U.S. in general. I know our demand office has a different number, but that's for California specifically. And we use EIA's number to kind of match their work.

And we have to 2.4 percent growth rate in the high demand case and 1.4 in the low demand case.

Renewables, we have California meeting its renewable standard goals and all states that have an RPS target, that they're going to meet their targets.

And the changes in the gigawatts in coal retirement, we have 75 gigawatts retirement in the high demand case, and the low demand and mid are both going to stay steady at 65.

And for the cost of capital and resources and the maintenance costs for the low and high demand cases, we have them being 30 percent higher or lower. And we've also eased in the prices this year. Usually we just do -- it's like 2019 prices jump 30 percent or decline 30 percent this year. Each year it goes up by 10 percent to kind of smooth out the projection so you don't have this huge jump between the cases.

So this is more of the initial demands. These are what we put into the model and then the model itself changes them.

So some of the performance of the cases on a national level. So here we have our three cases, which are the blue, red and green with the black line being EIA's forecast. From this, as you can see, we pretty well mimic what EIA is seeing in their reference case.

And this is for Henry Hub, which is the main pricing point for the United States and North America. Basically all of their gas prices kind of follow this one. There's always local problems.

So we have prices varying between $6 in our low demand/high price case and $2 in our high demand case with it being around $4 out to 2030 in our mid demand case.

So once again, we see very flat, very low prices for natural gas. It's just there's a lot of it out there.

This can all change. Policy could come along and change it. A new administration can change it. A lot of this is also dependent on oil prices again.

Gas and oil used to kind of trend together, then they diverged, and now we are kind of finding -- we've done some preliminary research on it. We're finding they are still going together, but they're going in opposite directions. So as oil prices go up, gas prices are going down because of the associated gas that goes along with it.

So we're seeing this new thing going on. We're actually seeing them going in opposite directions.

And so we have our demand. It's increasing, just not a whole lot. This is U.S. overall. So our annual growth rate in the mid demand case is a little over one percent, and most of this is industry and -- industrial and Power Gen is where most of the growth is. We see very flat and low for residential and commercial.

A lot of this has to do with energy efficiency standards throughout the country. Even though there might not be a federal mandate for this stuff, a lot of the states themselves are stepping up and doing their own.

And this is -- for the U.S. this is the Power Gen sector, which is one of the largest increases we see. Right around one percent in the mid demand case, a little over one percent growth in the high demand and about a half a percent in the low demand case. This is where most of the growth is. It's a lot of the coal switching. A lot of people -- the most cleaner -- cleanest of the fossil fuels I guess, it's cleanest of the bad stuff.

And we see production increasing. A lot of this is driven by exports, especially in the LNG sector. We have our highest record LNG and we're still increasing. There's a lot of projects that are being built, expanding Sabine Pass. These guys are just pushing it out. As long as our gas prices stay super cheap, we can stay competitive on the world market.

And more of California. So the three -- well, Henry Hub's a main for the national level and two of the main pricing points coming into California are Topock and Malin. Malin is the northern hub. This brings gas out of the Western Canada basins and the northern Rocky Mountains out of Opal. And Topock brings gas from the Southwest from the San Juan Basin in the Four Corners area in West Texas.

We kind of see the prices. They continue to trade at a discount, the Henry Hub, because of the low cost coming out of West Texas and Western Canada. And this discount from Henry Hub is going to widen over time. As we see, these basins continue to produce extremely low cost.

And the basis of the difference between Malin and Topock, we kind of see staying consistent over the forecast period.

So as we can see, U.S. natural gas demand grows about one percent between 2018 and 2030. Our Henry Hub prices are staying low. And our production is going to increase, mainly driven by the LNG.

So a couple things to also consider with our cases. We're working very closely with PLEXOS from the production cost modeling team to make sure things line up because as we change things and prices change, it changes the -- where gas is going to be used for them. When they change it, it changes ours.

So we're doing a lot more inter-work between the two of us this year that we've not done in the past and it's really nice to see that we're doing this and really working to try and get our cases to kind of coincide with each other. It really makes sense and to have the story behind why we see certain things happening.

And another piece of the puzzle is, there's a bridge between what I produce in the NAMGas model and what we produce in the PLEXOS model, which is called the burner tip model. It gets a lot of attention because it's the prices that go into the production cost modeling. But it's key to understand that what drives that model are the prices that come out of the NAMGas model.

I know a lot of people call about the burner tip and they really focus on it, but the burner tip basically takes the annual price, breaks it up into a monthly price adds a transportation cost, which are all givens. We do research to find out what those transportation costs are. They're not something we just come up with.

So what really drives the price changes in that model is the NAMGas model. So what happens here really produces that, which can really affect the PLEXOS modeling. And their modeling can really affect ours. And that's why we're really working through this time between this run and the runs that we'll have done sometime in August is really working to get these things to coincide.

So some of our next steps. We're going to keep monitoring and looking at the price volatility in Southern California. We want to better incorporate the LNG market. Right now it's kind of static in our model. We're trying to make it a little more functional.

We're going to continue to revise and work on the small "m" model. We'll be incorporating the preliminary CED forecasts into our model. We're going to continue to develop this monthly model and we're even thinking about trying to do a one-year daily model so we can really get some granularity and really work with the PLEXOS and find some -- where we can really look at things that happen with Southern California, with any kind of supply issues, pipeline outages. We can really look at that at a very granular level.

And these results will be presented in the fall workshop, including our sensitivity cases and really distinguishing, making sure people know that there's an annual in some of these monthly fluctuations that we're seeing.

So are there any more questions or comments?

VICE CHAIR SCOTT: I think we're good. Thank you very much.

MR. DIXON: Thank you so very much.

COMMISSIONER McALLISTER: Thanks very much.

VICE CHAIR SCOTT: I just want to acknowledge that Commissioner Douglas has joined us.

So next is Robert Gulliksen also from the Energy Commission.

MR. GULLIKSEN: Good morning, Commissioners and everyone.

So today I'm going to talk about our little "m" model, which is our basic demand model which feeds into our NAMGas model. I'm going to first talk about the four major sectors that make up the demand -- most of the demand.

We're going to talk about each sector's factors that factor in to determining the demand and some updates that we recently applied.

So little "m" is the linear regression model inside of an Excel spreadsheet. It uses past data that goes back to 1986 to project into the future. And we source things like prices and things from various sources, usually federal sources since we model each state.

And so we'll go over each sector.

So first we have the residential sector. It includes all dwellings. The main factors are weather, and that's basically heating degree days, since heating homes and individual domiciles are mainly driven by that demand in terms of cold days.

Population is one of the main factors in residential since our population needs more dwellings. We use the most recent state census data to do that. And that's also pulled from states and into future forecasts from the census.

Natural gas prices, of course, because once that's lower, then the demand usually rises.

Income, which is mainly just we use GDP.

And then also heating oil prices since it's the other major competitor to natural gas with heating the residential sector.

So next we have the commercial sector and this is also in part driven by weather, although less so than a residential case since the commercial sector is presumably -- you know, things are not -- buildings are not inhabited throughout the night or during --

COMMISSIONER McALLISTER: Quick question.

MR. GULLIKSEN: Yes.

COMMISSIONER McALLISTER: On both cases for residential and commercial, you've called out heating oil price --

MR. GULLIKSEN: Yes.

COMMISSIONER McALLISTER: -- as sort of an input. So how prevalent -- or I guess what's the influence of heating oil price in this model? I mean how prevalent --

there's not a lot of heating oil happening in California.

MR. GULLIKSEN: Sure, yeah. But since we're having to do national data, so a lot of times in places that are not -- that are either older buildings or places that -- many places do not have a natural gas service, there's -- and so it's kind of the major competitor to natural gas price.

If there's -- there might be some places that have either both and could presumably switch as an alternative.

COMMISSIONER McALLISTER: This is a market competitor that's --

MR. GULLIKSEN: Yeah. And it's --

COMMISSIONER McALLISTER: -- (indiscernible) the retail natural gas price.

MR. GULLIKSEN: Yeah, and it's not everywhere obviously, but it's just in some places it can be a competitor to natural gas.

COMMISSIONER McALLISTER: Okay. Thanks.

MR. GULLIKSEN: And of course -- so anyway, weather is not as much as a determiner due to the fact that it's not -- that commercial buildings are not normally inhabited throughout the night.

And of course we have population. More population means more commercial buildings are needed.

Income again.

Natural gas price of course because that's what we're modeling.

And so next we have the industrial sector. One of the -- the biggest prominent factor in the industrial sector is obviously industrial production, everything from food preparation and processing to refineries. Mostly this is either from something you need to provide heat to or on-site energy generation.

And, again, weather is a smaller factor, and this is because there are less employee areas or the employee areas may not be as controlled or as numerous as either residential or commercial buildings.

And again natural gas price is the major factor in this since it's the big determiner. Higher price means less demand and lower price.

Then we have finally the electrical generation sector. In this case, the weather is -- weather in this case is determined by the cooling degree days since power for air conditioning is necessary and of course drives the power generator to want to -- have need to produce more electricity.

One of the main -- and of course natural gas price. Fuel oil, again, as a competitor. Renewable generation as a competitor. And coal prices, coal as a competitor.

So the competitors obviously will -- if they're lower priced than natural gas price or it's higher -- or natural gas price is higher, then it's going to depress demand and vice versa for natural gas prices.

And we also have a transportation sector that we do, but compared to these other four, it's very, very small and doesn't really carry as much.

VICE CHAIR SCOTT: Robert --

MR. GULLIKSEN: Yes.

VICE CHAIR SCOTT: -- how you can tease out the differences between some national numbers where it might be easier on your previous slide for folks to switch from a natural gas to coal or to fuel oil versus in California where they probably don't have the option to switch as much.

So can we kind of tease out the California trends from the national trends with those prices?

MR. GULLIKSEN: Well, each of our -- when we calculate the prices with it, we take it from either -- usually federal data.

So we have a set of -- basically we take the national data and we split among the states, the prices. And mostly they're -- but in some cases I believe we might have some different ways they're split up or their proportioned I believe. I might be mistaken.

But mostly it's just -- I thought it was like an overall as a competitor.

VICE CHAIR SCOTT: So we're really just looking at national trends there.

MR. GULLIKSEN: Yeah, and we have -- the output does do state by state annually. But, yeah, I have to look at that.

So the way that we use our little "m" data is to put it into our natural gas input and so it basically provides a baseline, the reference demand for each time period, so for each year in this case, for each demand region defined in the natural gas model.

So, for example, each state will have demand nodes, one of each of the four major and of course the transportation as well. And basically we break those up in some states.

For example, things like New York, for example, is split into the major like Long Island, New York City, upstate, east/west, because there's so much population density. And so we basically have a process to break out the data and plug it into the demand nodes of "m" gas.

And so each of those, and then from there, the "m" gas of course continues to model onwards, considering supply pipelines -- supply, pipeline developments and the price fluctuations and it tweaks it from there.

And there's one thing about the -- that California WECC states' electrical demand, on this slide I did not put electrical demand but -- this is only electrical data -- is supplied by our PLEXOS modeling for 10 years. And so it's a fixed amount in all of the power demand.

So out 10 years and then we use those 10 years to then go from there to extrapolate from that 10-year data.

So in that case, for California WECC data and WECC states, the little "m" data is not used, at least for power demand.

And then -- so one of the big recent updates we're most proud of is the updating of our cooling and heating degree day with climate change data in consideration. Basically it incorporates past climate data as well as modeled future cooling/heating degree days out to 2025.

It uses upgraded population data from the 2010 census which was the last -- and it's population weighted for either the top three metropolitan areas with at least 80 percent of the state population or the five most populated metro areas of each state.

And it was sourced from the Energy Commission's research and development division and we also did some update on alternatives for coal, which can help with the competitive things and which has less importance obviously.

COMMISSIONER McALLISTER: Hey, Robert, have you done any scenarios on climate data to see how that's likely to influence the natural gas demand over time?

MR. GULLIKSEN: I haven't done that as of yet. That's one of the things I need to look into.

COMMISSIONER McALLISTER: It would be nice to sort of capture the scientific conversation about where things might be going. I mean it's a long way out so things may end up in different places.

MR. GULLIKSEN: Yes, certainly.

COMMISSIONER McALLISTER: And then also a question on heat rates for coal. What influences -- I mean presumably they're -- well, actually which direction are they even going, I guess is the question. Are they getting better, are they getting worse, you know?

MR. GULLIKSEN: I haven't looked at it in a while but I certainly can get back to you on that.

COMMISSIONER McALLISTER: Yes, it would nice to know sort of where that markets is going in terms of its efficiency as we're seeing all these retirements and what that's impacting, how that's impacting.

MR. GULLIKSEN: All right. So now we're going to just go over the changes that we saw.

So the original is in the blueline and our updated on one is the redline. And now we can actually see at least -- it's hard to see in this case since the heating degree days don't seem to change much, but they have a general downward trend instead of a -- and before what we were doing was -- from the original draft was to take a 25-year average from the most recent outward.

And this was from our -- from last cycle. So the updated one actually has a nice downward trend, and this makes sense because there would be less days that are cold enough to need -- a need heating demand.

And of course our cooling degree data has a nice upward trend, which makes sense considering there would be more days needed -- with cooling might be needed, more warm days.

And it closely follows the data until about our last comparison where it begins to trend upward which is better than using the -- on average what we were using before, which sort of makes everything the same.

So future updates that we're going to start doing is re-addressing our regression equations and that sort of thing, just to make sure there's any tweaks that might be necessary to better model demand.

We're to investigate the historical, how far back we'd like to go considering the changes from the recent so-called fracking revolution after 2008. This is mostly because the market changed so much after 2008 and the introduction of fracking, that it might be worth looking into the fact that instead of using linear regression from 1986, since things were so different, it might be worth having a cutoff much closer.

COMMISSIONER McALLISTER: I'd like at some point when you make some progress on that, get a briefing about where you're landing on that.

MR. GULLIKSEN: Okay.

COMMISSIONER McALLISTER: Because it would be nice to know, you know, where the discontinuity really lies analytically and that -- it would be nice to kind of get into that decision-making process at some point, when you guys are ready.

MR. GULLIKSEN: Okay. And then what we wanted to modify the little "m" to use the monthly time periods instead of annually to support NAMGas monthly modeling.

And that's all I have for you today. Any questions or comments?

COMMISSIONER McALLISTER: All right. I think we're good. Thanks very much.

MR. GULLIKSEN: Thank you very much.

MS. RAITT: Thank you. So next is Angela Tanghetti from the Energy Commission.

MS. TANGHETTI: Okay. Good morning.

So, again, the first part of this presentation is going to be a repeat of what my colleague Richard Jensen provided at the March 4th IEPR workshop on inputs and assumptions.

I apologize also if I'm going to bounce between comparisons of the 2017 IEPR update and then draft and preliminary IEPR assumptions and results.

Let me just get to the next slide.

Since our modeling efforts are direct input for NAMGas, we need to have our simulation results ready in about the January time frame. So later in this presentation, I'll share the results. I'll be referring to them as draft, and that's what we presented at the March 4th workshop, as well as preliminary production cost model results, which are the results of the new NAMGas prices that we just got past recently.

The draft results I'll share are production cost modeling results, again presented at the March 4th workshop. And the preliminary results, again presented today, only differ from those draft results by the burner tip prices that Anthony has just described.

Our team uses -- the research tool for the production cost modeling is the PLEXOS tool and these provide the NAMGas team natural gas use for electric generation in the Western interconnect.

Therefore, for NAMGas to provide natural gas prices to present today, our team provided the PLEXOS draft results presented at the March 4th workshop.

The results I'm presenting today are basically going to demonstrate this iteration process between PLEXOS and the NAMGas models. And more iterations are needed before the next Outlook workshop where we will be presenting results not only based on this iteration but also based on the preliminary IEPR 2019 demand forecast that's expected in about August of this year.

So, again, when you see "draft" in this presentation, that will refer to the results Richard and I presented during the March 4th workshop, while "preliminary" will refer to our first iterations with the NAMGas model for burner tip price projection.

So, again, let's see, the first five bullets up there are -- four bullets are basically unchanged from the March 4th workshop. The last two bullets, I'm going to provide what we presented on March 4th and then also preliminary results today.

So with that, I just want to remind stakeholders and Commissioners of the key demand and RPS assumption drivers included in the PLEXOS common cases. The assumptions are consistent with SB 350 and SB 100.

So, again, the high energy consumption case is characterized by low prices while the low energy consumption case is characterized by high prices.

So, again, these are some of the other key drivers for demand and RPS and those common case assumptions.

Again, these are links to the demand forecasts and our PLEXOS model. Richard went over those at the March 4th workshop, and they're available at these links.

Again, our demand office does provide hourly profiles for the -- so balancing authority area LSEs in California, and those do include the impact of climate change.

So you were asking about the impact of climate change. So we definitely see on an hourly basis in each year those projections either increasing or decreasing, given the hour, to account for climate change.

Unfortunately, we don't have -- as our knowledge base gets further out of California, we are not able to quantify those impacts and our demand forecasts at this time for regions outside of California. But we do incorporate them for California, which is a major portion of the WECC as well.

For regions outside of California where we don't have the luxury of getting the hourly demand forecast, we've developed a load shape tool that takes five years' worth of historic data and creates a synthetic load shape on this.

It's about a 20-year-old tool, but the technique is still robust. The only thing that we do differently now is we adjust those load shapes for behind-the-meter PV and AAEE so we can capture peak shifts in those forecasts.

Again, this is what we presented at the March 4th workshop. The red bars being the demand forecasts that we're assuming for regions outside of California, and we gather that from the anchor data set which WECC puts together and then we interpolate -- or extrapolate, excuse me, to get to 2029 and '30. For the years in between, we interpolate from the last historic year to their 2028 anchor data set.

For retirements, again, this is unchanged from our March 4th workshop. The only change you're going to see in these simulation results later on are the burner tip prices.

So, again, we look at the OTC compliance schedule, the CAISO retired and mothball list. We refer to subscription databases, trade press. We have a 40-year-old rule for resources in California if they reach 40 years of age and they don't have a contract, and their thermal resources, they are retired during the forecast period.

And then we also rely on the WECC anchor data set.

Again, these compliance cases, these resource builds or retirements are common to all the cases. There's not one with more retirements than the other.

Let's see, the next slide, again, is our resource assumptions for -- or retirement assumptions for California and the rest of the WECC. As you can see, in 2019 there is a projection of a large amount of coal retiring in 2019. And the majority of that is from the Navajo plant which is expected to retire at the end of 2019, and that still seems like it's on track for retirement this year.

Again, by the end of the forecast -- WECC includes, you know, Alberta, so there's significant coal retirements in Alberta. The California natural gas fleet is second largest in the retirement scheme for the West.

Our additions. Thermal and renewable additions also come from a variety of sources where we are able to verify them from not just one but from multiple sources.

So our team considers the source when we are looking at the addition and if it appears in more than one of our sources. So if just appears in a single source of a trade press and we can't find it anywhere else, we don't consider it robust enough to include as an addition.

The CPUC and CEC IRPs have provided the majority of California renewable additions in this version of simulation results where the WECC anchor data set, as well as utility IRPs for regions outside of California, kind of round out our renewable and thermal portfolio builds for the rest of the WECC.

Again, this is unchanged for the assumptions we presented at our March 4th workshop, and these are projections for the existing renewable portfolio in our current year, which is 2019. So you look at 2019 and this is basically the current portfolio as we know it today for in-state only resources.

For the mid demand case, we assume that California will continue to procure about 30 percent of renewable energy to meet the RPS from resources located outside of California.

For the low demand case, we assume that about 15 to 20 percent of imported energy will be needed to meet the RPS.

And the high demand case, we assume -- we rely a bit more on our neighbors for out-of-state imports to meet the RPS, so about 35 to 38 percent of imports are needed to meet the California RPS in the high demand case.

A key driver in the productions for natural gas demand for electric generation is hydro generation. Our hydro generations are based on a rolling average of the prior 15 years. Hydro generation, the greenish line is what we're assuming for average hydro generations in the simulation results we're presented today.

2017 is what many consider an above average hydro generation year, and 2015 is what many consider a very low hydro generation year.

It's also important when somebody provides you historical gas use for electric generation to consider the hydro generation year in that historic year. If you compare 2015 to 2017 gas use for electric generation, you can explain some of the variation not just on demand but what is the hydro generation in those years.

So it's really important when you're looking at historic gas use to understand the historic hydro generation in those years.

Our monthly projections for the rest of the WECC, average hydro are shown in the red line. I think next time that I want to present high and low hydro generation for out-of-state just to kind of round it out.

It will be interesting to see if 2015 and 2017 are also coinciding in California, because what we found is that you can't always -- when it's dry in California, it doesn't always mean it's dry in the Northwest, so it would be interesting to see the variation in those forecasts those years. So for the next workshop we'll add that data to the slide.

Okay.

COMMISSIONER McALLISTER: Are you looking at snowpack? Like this year looks like in California, resources are going to be relatively robust.

MS. TANGHETTI: Oh, we don't generally look at snowpack. What we look at is actual hydro generation, so it's interesting because snowpack kind of depends sometimes when it accumulates. So whether the runoff will come early, whether it's really hot in May or it's not a hot May -- so that's why we tend to look more at just strictly the generation and not the snowpack.

COMMISSIONER McALLISTER: Okay.

MS. TANGHETTI: Okay. Now, for the key drivers that have changed since the March 4th input and assumptions for PLEXOS.

Sorry, the slide shows March 5th but it was actually the March 4th workshop date. So if any stakeholder is looking for that, you need to look at our website for the March 4th.

As Anthony already described for you, the near-term price projections are much closer to the mid than they were in the draft prices. So the draft prices on in the lower half of the screen. The preliminary prices are what we're using right now.

So if you look at the year 2020, the high and the low energy consumption cases are much closer to the mid year 2020. So we don't have that big spread starting in 2020, like the high prices don't get very high and the low prices don't get very low in 2020. So they're closer to the mid, and they do spread out by the end of the forecast period but not nearly as great as in the draft prices that we used earlier in our simulations.

So, again, the burner tip price projections are generally lower in all three cases. And this does have an interesting implications for both in-state and out-of-state gas use for electric generation for both the near term and long run.

There many more burner tip pricing hubs that we include in PLEXOS, but we chose a few that just either are trading neighbors that are very close or else they're large consumers, like Colorado is a large consumer of gas for electric generation in the WECC.

So these are a few of the burner tip prices, but there are many more out there that we use in our simulation tool.

Okay. Now, for the draft simulation results and the preliminary.

The draft simulation results presented at the March 4th workshop are characterized by the dashed set of line. So, again, high is always in the green but the dashed is what we presented earlier and that are in these NAMGas simulations.

And then the solid lines are a result of these new prices. So as you can see, they're generally lower in these simulations and it's strictly based on the differences in gas price.

The crossover after about 2027 is due to price projections as well as our assumptions about RPS imports. The low demand case assumes most of the RPS generation will come from in-state resources. So in-state gas is actually cheaper right now to form and shape these renewables.

The low demand case also has higher gas prices, which creates a shift for out-of-state gas to coal since coal is now significantly cheaper than gas generation. Since California cannot import generation from coal, more generation is coming from these in-state resources.

You asked earlier about looking at the shift between locally -- not locally but not nationwide. If you want to look at it from California WECC-wide perspective, we can see the impact of the price differential between gas and coal and when you shift from gas to coal at what price differential there is.

If you look back at the slide at the draft prices we use, sometimes you'll see $8 gas prices, and that high of a gas price does create a shift in the WECC to additional coal generation.

So let's look at that from a WECC-wide perspective just from gas use. And while the lowering of gas generation in California, we observe a higher starting point for gas use outside of California.

Interestingly, the low demand case now has a downward trend since the spread between near-term natural gas and coal prices is not as great as we observed in the draft price projections. So earlier, there was a bigger differential so we saw more of a shift.

Basically, the low demand case simulation results are projecting a higher starting point than the draft results presented at the March 4th workshop.

In the coming weeks, we will definitely be iterating with the NAMGas team on natural gas price projections. And we're expecting to see less and less a change from each case.

For the next workshop what we plan to present are these final iterations of the NAMGas and PLEXOS results. And then in addition to that, we're going to have the draft or the preliminary IEPR demand forecast, so we'll be able to see just the iteration result between PLEXOS and NAMGas, so we'll be able to see the impact of prices on electric generation and then we will also be able to see the impact of our new demand projections on any kind of impact for gas.

COMMISSIONER McALLISTER: Angela, could you -- I might have missed it, but could you talk about the different -- particular with the low scenario, between the draft and the preliminary in terms of -- it looks like about 30 percent higher usage in 2020.

MS. TANGHETTI: Yeah. So in the low demand case, the price variation in the first year started out very different like the high -- the low demand case is characterized by high prices and they started out high in 2020.

So when they started out so high in 2020, you got a definite shift to coal in that year.

COMMISSIONER McALLISTER: Okay.

MS. TANGHETTI: So when we start looking at GHG results, you're going to see -- from a WECC-wide perspective, you're going to be able to see like the GHG results in the draft were much higher than they are in these current simulations just because we had a big shift to coal because our gas prices started out so high.

COMMISSIONER McALLISTER: Okay. So you've got the gas here, but in terms of greenhouse gases, obviously --

MS. TANGHETTI: It will look like something different.

COMMISSIONER McALLISTER: -- it looks actually better.

MS. TANGHETTI: Yeah, it does look better. Even though we have more gas early on, the GHGs are -- implications are lower.

And it's interesting because we use EIA for our gas price projections, the Annual Energy Outlook. And in between cases, they have eight cases of coal prices, but there's very little range in those coal prices. No matter whether you're looking at high economic growth or low economic growth or high or low technology, coal prices are just kind of flat through the forecast period.

So when we do have significant change in gas prices, we do see a shift in the rest of the WECC.

So, again, as you asked, the price impacts -- I think what we'll do next time for the next presentation is provide gas -- excuse me, coal generation, coal use for electric generation for all the three demand cases so we can also see the spread in WECC-wide coal use.

Because with SB 100 we're supposed try to understand any leakage so it will be interesting to start looking at coal generation notches, GHG projections as --

COMMISSIONER McALLISTER: Yes, exactly. I mean at some point -- I mean this is may be a conversation for another day. But there's a -- if we're going to meet our

SB 100 goals there's going to have to be some pretty muscular policy along the way.

And so we may have lots of natural gas and revolution and fracking and all that and low gas prices, but we may have mandates not to use that gas or some pathway that is a low gas pathway that's more driven by policy than it is by price.

MS. TANGHETTI: Exactly.

COMMISSIONER McALLISTER: So I think that's going to be sort of turning some of this on is head, which will be interesting to figure out how to model and embrace.

MS. TANGHETTI: It's really interesting and a challenge to model now, because when we start looking at planning reserve margin in the future and we keep pulling out our gas plants, I have nothing in my quiver to put in there -- say, if you start looking at building electrification at 5 o'clock in the morning, all I have is storage. I don't have -- there's no solar, there's no wind. So I'm looking at storage.

So that's the only little tool in my quiver that I have right now to meet a load at those low hours that are GHG.

COMMISSIONER McALLISTER: Yeah, and policy has to step in and try to give you more tools.

So I think the next five years is going to be interesting.

MS. TANGHETTI: Yeah, this has been really intriguing. It's fun to share these results and hear your questions so that we know better how to tailor our presentation for next time, because we've never thought of looking at coal use for electric generation, but I think it's something that we really need to -- and we have the tools to do it and we have the data so we'll be happy to package it up for next time.

Okay. Now GHG projections. So, again, just because we have a crossover in gas use doesn't mean we have a crossover in GHG projections. They are on the downward trend, definitely. But when you quantify imports into the GHG calculation, then you see this still separate trend between mid, low and high.

And I didn't going into detail about the GHG counting from the March 4th workshop, but stakeholders are -- I left the link in there so if you want to look at the methodology that we developed to quantify emissions on imports, that data is all there.

I didn't do a chart for the WECC-wide perspective, but again, your question -- if you look at the draft, which is in the lower half of the screen, the draft low projections, again, you looked at that big jump in gas use for the rest of the WECC. But, again, it has lower projections in this round because we don't have the coal to gas switching earlier in the forecast period.

So even though we're using much more gas in our preliminary low demand case, the emissions are much lower. So you can see the tradeoff there. So the lower chart is really kind of counterintuitive but was really a tradeoff since the gas prices were so high early in the forecast period. We were definitely generating with a lot more coal in that time period.

So, again, we have less near-term variability between mid, low and high burner tip gas price projections, so that leaves us with the 2020 projections more in line with what we'd expect for mid, low and high, less coal to gas generation switching in both the long run and near term drew less variation between the coal and the gas burner tip price projections.

And the preliminary high is just flatter GHG trajectory due to lower near-term burner tip prices. So, again, the high demand case doesn't have as low prices early on so we don't nearly as much gas use.

VICE CHAIR SCOTT: Angela, do you have a sense of where the 40 percent below 1990 levels line would cut across here? Or is that something that we -- so WECC-wide probably not referred but the California portion of that, it be interesting to know if preliminary low, mid and high are all way above it, approaching it, you know, below it. It would be interesting to have that data point I think.

MS. TANGHETTI: That's an interesting question because the 40 percent is from an economy-wide perspective.

VICE CHAIR SCOTT: Yeah.

MS. TANGHETTI: When we look at the electric sector, we look -- oh, hey, we look great. But from an economy-wide, it's hard to fit that in because we're only -- if the pathways tool is something that can look at that, but again this is only the electric sector.

And, again, this is without significant electrification. We're going to wait to see that in the preliminary demand forecast that's coming out in August of this year. And maybe by 2030, we will see some additional significant electrification, building electrification -- or building fuel switching, is that the right -- fuel substitution.

COMMISSIONER McALLISTER: The term of art these days is "decarbonization."

MS. TANGHETTI: Decarbonization, okay. So that's what we will be looking for in order to incorporate there.

So, you know, from just a strictly electric sector perspective, we can say yes. But from a sector-wide perspective that's a number that we can't quantify right now.

So that's all I have for now until the next iteration.

COMMISSIONER McALLISTER: Thanks, Angela.

MS. RAITT: Thank you.

So next we have Jonathan Bromson from the California Public Utilities Commission.

MR. BROMSON: Good morning. My name is Jonathan Bromson. I am an attorney with the California Public Utilities Commission.

My colleague Jamie Ormond was invited to present today but could not be here. She has been the policy person spearheading biomethane and renewable natural gas efforts for the last year and a half at the Commission. She is extremely enthusiastic and very fun to work with. I will try to channel her today.

I personally have worked on natural gas for the Commission for almost 20 years representing the Commission at the Federal Energy Regulatory Commission on interstate pipeline matters, advising Commissioners more recently on reliability issues, particularly the Southern California gas infrastructure issues, but a whole wide range of gas issues including biomethane for the last year and a half.

I also have some background with what is now known as California Advocates or Public Advocates. It used to be known as the Office of Ratepayer Advocates. I represented them in the initial rulemaking that I will talk about briefly, which is Rulemaking 13-02-008, so I can't advise the Commissioners on that one because I'm conflicted out.

But I have a reasonably long background with natural gas, and we are excited both in the state and at the Commission that renewable natural gas in various forms is now mandated to be used. You know, the electric sector has for very good reason captured most of the attention because of the switch to renewables.

It is exciting for the natural gas world and new to have natural gas sources that are considered more environmentally beneficial and particularly because of avoiding either direct venting or flaring into the atmosphere. And it's crucially important for the state policy to capture that gas and use it beneficially.

So just to -- I don't want to define these terms. It's an umbrella of terms here. You know, renewable natural gas comprises biomethane and renewable methane. It also comprises hydrogen sources, which is electrolyzing hydrogen form renewable electricity.

We're not going to get -- I've included some slides here. Jamie is very much enthusiastic about our hydrogen efforts. They're not the most direct efforts that we're working on now, but it's the next phase of work that we are doing.

But in terms of summarizing the efforts that we have done to date at the Commission, you know, hydrogen is sort of the next thing.

There's been a lot of legislation over the last several years to encourage and mandate interconnection and use of renewable natural gas and biomethane in California. It started with AB 1900 in 2012 to develop biomethane pipeline injection standards. It continued -- it's accelerated over the last few years because the process has taken a little bit of time.

Senate Bill 1383 in 2016 required the Commission to develop at least five dairy biomethane pipeline interconnection projects to significantly increase the production and use of in-state biomethane from dairy and electric and transportation industries. And I'll talk a little bit about those efforts.

SB 840 required the California Council of Science and Technology, CCST, to take a deeper dive into the heating value bands and the siloxane concentration within biomethane to sort of look again at some of the findings that the Commission had initially made in the rulemaking I talked about earlier.

SB 2313 extended the end date for the interconnection incentive program that had been started in response to AB 1900.

SB 1440 of last year requested the Commission to look into cost-effective renewable natural gas procurement, to have core customers purchase renewable natural gas to kick-start a market and increase demand.

AB 3187 continued sort of work on the renewable natural gas interconnection.

And SB 1369 of last year required the Commission to consider hydrogen as an energy storage source.

And let me also just thank you for -- I do a lot of work that has economic consequences, so the modeling that has been done here is very similar to modeling we see both in-state and from wider use. So that sort of work is really important for what we do.

We're not quite yet at the level of use of renewable natural gas where that is impacting in the short run prices. As we get -- you know, over the next decade that is going to impact supply and prices, but how much is still up in the air despite the policy goals and statute.

California imports about 95 percent of the fossil natural gas that we use every day. Increasing in-state biomethane will basically replace what is a declining in-state natural gas -- you know, traditional natural gas supply situation.

And as we know, the current California gas market has been impacted by in-state infrastructure failures, particularly in Southern California. The regulatory actions that the state should take should help meet the state emissions reduction goals.

And moving towards a system that flows a decarbonized or zero carbon gas product could reduce system and end-use carbon emissions and reduce a negative health impact, increase jobs and enhance in-state system reliability.

It is too early to tell how much RNG will be introduced and when into the California supply. But reducing waste gas from flaring directly into the atmosphere, and instead putting it to beneficial use via pipeline injection for use in electric and transportation sectors, moves the state towards the short-lived climate pollutant reduction goals. And we referenced the ARB's reduction strategy from 2017.

Now, the dairy pilots -- there is a website here, a link to CPUC website with renewable natural gas. That has a whole bunch of -- more deeper dive summary materials and beyond just our dairy pilot programs.

But we opened a rulemaking in June of 2017 in response to SB 1383 to solicit and evaluate dairy pilot projects. And we have chosen six dairy pilots, and I didn't list them here but I do have a list of them somewhere here.

Of course I can't find it now that I've prompted myself.

But we chose six dairy pilot projects, and at the moment we're reviewing the contracts for the purchase of the dairy biomethane. The amount of -- the pilot projects are all around the state. Most are in the Central Valley, but one is up in Willows in Glenn County.

The six selected projects comprise a little less than 6300 MMBtu a day. So the amount is negligible at this point. And the total installation cost is not insignificant. It's about $132,000,000 because pipes are expensive. And getting pipes from the dairies to larger existing natural gas infrastructure within the state, that is the largest amount of cost that we're going to be dealing with.

And because there isn't that -- you know, pipes are usually cost by miles. You know, thicker pipes, larger quantity pipes cost a little bit more, but it's how long you have to go. And so the up-front costs for a lot of renewable natural gas are going to be a barrier. And so having legislation that helps cover those costs is very key for getting the gas onto the system.

The annual O&M costs are estimated to be fairly low though, $1.4 million. So once you get the pipes in the ground, the marginal costs of running these facilities isn't that much. So it's going to be key to helping dairies and landfills and wastewater treatment plants get connected to the system.

Now, in terms of influencing the market and the market price at this point, the key is our incentive programs from other government agencies.

California Air Resources Board provides low carbon fuel standard credits, LCFS credits.

The federal EPA has renewable identification number -- RIN numbers. And they provide a larger amount of subsidy or credit towards the transportation sector because the existing transportation sector, using gasoline, using petroleum product, even just switching to traditional natural gas provides significant benefits for air quality and carbon emissions.

But when you use renewable natural gas, and particularly dairy where you're avoiding so much emissions directly into the atmosphere, the benefit of -- getting the benefit of avoiding those emissions creates a large amount of LCFS and RIN credits. And so that is low hanging fruit of using renewable natural gas both in terms of its impact and in terms of where the incentives are today.

Now, currently the CPUC is engaging in a number of different ways with renewable natural gas. Southern

California Gas -- both the major utilities, which are Southern California Gas Company and Pacific Gas and Electric Company, have procurement pilots for use of compressed natural gas pumps.

They both have pumps for their own fleets and to the public for natural gas fueling vehicles, and now they have pledged to switch to only using renewable natural gas for use in vehicles.

And with the LCFS and the RIN credits, they are in the money basically. It is cheaper to use renewable natural gas than traditional natural gas.

Now, we know that the gas commodity is very cheap and it's still expensive to transport the gas end-use customers. But even with the gas commodity cost, these credits make the gas cheaper.

We want to engage in renewable natural gas pipeline interconnection tariff standardization throughout the state. Southern California Gas and PG&E have different historical models and have different tariff rules. They may not be able to be totally standardized, but we would like the industry to be able to know that whichever utility they're interconnecting with -- and then Southwest Gas is sort of the third largest of the investor-owned utilities. We would like them to be able to know what they're dealing with, but as I say, history has meant that they have had some differences.

The most recent application to the Commission that impacts procurement is Southern California Gas's voluntary opt-in RNG tariff. It's Application 19-02015.

Because of the PG&E bankruptcy, PG&E has not yet made their own proposal. They have formally supported the SoCalGas tariff. SoCalGas is modeling it on some of the electric efforts that give customers choice to choose more environmentally responsible products. So core residential customers would choose how much maximum dollars per month they would assign for RNG purposes -- I mean purchases. And commercial industrial customers would choose a dollar amount or percentage of gas use.

Now, we don't know how much gas that is going to incentivize, and this is a pending application before the Commission. We don't know what exactly we will adopt and whether we would do something differently or not. But this is a start. And we have to -- we have been required to consider procurement mandates for core customers.

The Commission has jurisdiction over the retail market but not the wholesale market. And larger industrial and commercial customers -- it's arguable that we can't require them as the Commission, as the CPUC, to purchase renewable natural gas as a condition of using the pipeline system which is open access, but obviously other state agencies and policies can.

And the RIN credits and LCFS and other economic incentives can also help them.

We are going to be looking at biomethane constituents of concerns when they're updated in July 2019 and that has to do with heating value and siloxanes and other factors. And we are hopefully going to be considering hydrogen injection standards and further renewable gas procurement standards as time goes on.

Now, the next two slides start to deal -- I am not as familiar with hydrogen as Jamie is, but throughout Europe and other places in the United States, there is an increasing push to use renewable electricity to generate hydrogen.

Hydrogen gas can be injected into the pipeline system and could be seen as a form of storing renewable energy for electric generation and other uses, given the difficulties of electric storage and the ability of the pipeline system to provide storage through packing and through natural gas storage facilities.

When hydrogen is uses as a power source, the only byproduct is water. No carbon dioxide is emitted. So the key is whether or not that electricity can be generated from a renewable source. And if it's from a renewable source, then the hydrogen that is electrolyzed can be considered renewable hydrogen and can add to the state's plethora of options to provide renewable natural gas.

There was a discussion recently -- you mentioned building decarbonization. There is a debate within the building decarbonization proceeding about whether or not renewable natural gas should be considered. And I'm agnostic on that debate and that's not for me to discuss.

The CEC and other stakeholders are clearly going to weigh in, but the -- since the task we have is so large, it would seem with the renewable natural gas mandates, that to the extent that we're going to rely on natural gas for heating uses in homes and so forth, that it will be renewable natural gas, the growth of it is going to increasingly be important for the state to meet its long-term climate goals.

The CPUC, as we look at hydrogen issues, will look at production and electricity rates, transportation within the pipeline system and then storage, you know, in pipelines, in things like salt mines, in blended gases.

And there can be a seasonal time shifting of renewable electricity via storage in the pipeline system.

I'm not going to go through -- there's a couple more slides here, again, about hydrogen. There are still a lot of safety questions about hydrogen, about blending hydrogen with natural gas within the pipeline system that the state's going to need to examine.

Safety issues have of course been a much higher level of concern since the San Bruno incident in 2010 and with the leak at Aliso Canyon in 2015. And these concerns are paramount for the Commission.

Just in terms of proceedings dealing with the hydrogen aspect Rulemaking 13-02-008, which was the biomethane injection proceeding, that is still ongoing at the Commission and has some proposed decisions dealing with the heating value and siloxane content at the moment. And parties in that proceeding were the first to bring up, well, we should also be looking at hydrogen.

There's a relatively new rule-making from December of 2018 to investigate electric rates to produce hydrogen and there is the SB 1369 bill from last year to -- that hydrogen is to be considered storage.

And, again, some statistics and information about how hydrogen has been progressing within the state. In 2013 was $20,000,000 provided annually in AB 8 for hydrogen refueling stations.

Former Governor Jerry Brown's Executive Order anticipated 5,000,000 zero electric vehicles by 2030. And so there was a goal of a certain amount of hydrogen fueling stations.

By the end of 2018, 39 hydrogen refueling stations, including one privately funded, are open to the public. And currently another 26 stations are funded and in various stages of development.

I think the key to looking at RNG right now is we're in a push-and-pull situation. We don't have that much renewable natural gas that is interconnected into the system, but the transportation initiative, switching natural gas fueled vehicles within the state, both the fleet vehicles for the utilities and the public vehicles that use the infrastructure, converting them to renewable natural gas is a big start for encouraging the market.

Getting the dairy biomethane projects interconnected and selling gas is another factor.

But the key will be having goals for core procurement where our Commission, my Commission can require core customers to purchase a certain amount of biomethane or first starting with encouraging them to make that choice.

That's going to be where the market can gain some traction and get data and information about prices. We are dealing with a low price market. And as the projections of the market seem to indicate, when there is low prices, you have natural gas use. But when there is low prices, it's harder for renewable natural gas to compete.

But that said, these aren't just purely price considerations. And as we price in the carbon equivalent impacts of using natural gas into the pricing mechanisms, we're going to increase the use of renewable natural gas. And it is going to come from government programs.

And that is it for now. Thank you.

And I'm more than willing to answer any questions and also engage in any debate about the market projections because I think they were very good and, as I say, consistent with what we monitor when we're trying to look in the future at procurement for core and what electric prices are.

COMMISSIONER McALLISTER: Thanks very much. That's super, super helpful.

MR. BROMSON: You're welcome.

COMMISSIONER McALLISTER: Yeah, good stuff. And I do have a few questions.

I think this RNG discussion, there's a lot of fuzziness around it and I think it's part of the -- you mentioned, and we don't need to probe it, but the fact that there's kind of -- you know, there's electrification over here and there's kind of really -- RNG over here. And it's sort of near the two shall meet, right?

And so getting into the middle of that discussion and really sort of navigating this is partly our Commission's role and obviously it gets litigated in a lot of important ways, rates, et cetera, over in your Commission.

So I think really we have to work together to navigate this discussion in a way that's responsible and doesn't sort of project that we are picking winners but really kind of lets things move forward in a rational way.

Having said that, we've got two large expensive infrastructures, and what is going to be the long-term interaction between those two I think is a huge open question that we really have to delve into.

So you mentioned the cleanup standards that you're working on. Is that really about siloxanes or is there other --

MR. BROMSON: I think it's really more about heating value. I mean what happened over time at the Commission -- pure methane is 1,000 BTUs per cubic foot. And also natural gas is a little higher than that because it contains ethane, butane and some higher fuel content. And about 1030, 1035 is the average fuel content of natural gas nationwide and in California. And end-use appliances are attuned to a certain range.

And then -- but to get the water out of biomethane, particularly dairy biomethane, is very costly. The more that you get out the higher the heating value approaching about 1,000.

What happened when we were going to import liquefied natural gas, when Southern California Gas Company in particular, through their affiliates, Costa Azul, Energia Costa Azul import facility that's now being proposed to be an expert facility -- but they were supposed to import a bunch of hotter gas, maybe about 2004 or '5 and so they proposed increasing the minimum gas they could get into their system from 970 to 990, and that was accepted by the Commission at that point.

And that's a very high minimum level if you look at the nationwide standards. And the biomethane community wanted that number lowered, and that was part of the first phase of R. 13-02-008, and the Commission didn't approve it. And then the legislature wanted to have a neutral body look at that and that's where they requested that the CCST come in and provide a study. Their study came out I believe at the end of last year where they recommended that it could be lowered back to 970.

And you have to blend that 970 gas with higher heat value gas to get to the end users. But because of the amount of biomethane and the heating content of the other gas, it's doable apparently.

And that's what the CCST has stated, when we have two proposed decisions, at the moment, propose an alternate that would lower that heating value back to 970. And I think it will be received -- assuming one of those goes through with that, will be received fairly well by the biomethane industry. But it is slightly less heat content -- I mean energy content.

COMMISSIONER McALLISTER: So this is really -- it's not so much about toxics and sort of combustion byproducts and things like that anymore, because the last time I sort of aware of this, it was more about what was coming out of the landfills.

MR. BROMSON: Well, the landfills do have -- I mean for dairy biomethane, it's not about the concentrations. For landfills, it can be.

And I don't know the details of what we've proposed for siloxanes, but there's a general consensus that it can be cleaned up. But it is a problem. I mean it's hair lotions and all these things that get -- we need to be better as Californians in what we put in our landfills, but that's easier said than done.

COMMISSIONER McALLISTER: But is that in the same proceeding?

MR. BROMSON: That's in the same proceeding as well. So there's a discussion of siloxanes and it's Phase 3 of R. 13-02-008 and as I say, there are proposed decisions pending now. And I am not officially taking part in that.

This is my personal observations, because as I said, I once represented a party in that proceeding. So I am no longer advising.

COMMISSIONER McALLISTER: No worries. I'm just kind of interested in the latest, not in any sort of rulemaking depth.

So who's paying for the collection of the biomethane at the dairies, like in these pilot projects or beyond that?

MR. BROMSON: Well, I mean --

COMMISSIONER McALLISTER: What are these projects -- what are their boundaries, sort of participants and who's funding? You guys are funding -- MR. BROMSON: We are funding most of the costs. I mean when you sell gas, the cost of selling the commodity covered the cost of producing the commodity. And that usually includes the cost of interconnecting to a pipeline system. What the legislation did was to help cover those costs in other transportation rates. And so you give a leg-up because they're such high up-front costs. And all the costs are going to be paid by ratepayers in this pilot project.

Going beyond the six pilots that we've chosen, those costs are part of what when you sell the gas to an end user, you get repaid for it. And when you have the credits, depending -- either credits will go to the producer and they can lower their costs, or certain credits can go to the end user so they can add to the cost that they pay.

So it's going to be a combination of through utility rates and through direct bilateral contracting with specific end users. And you have a number of industries that are trying to step up and do the right thing, but also we're looking out at RIN and LCSF credits and going, well, we can do this.

So at this stage it's all -- I don't know exactly to whom all the sales are being made for the dairies. But they have markets for this gas. In the beginning it's going to be easier because there are a number of industries that are looking to do this. And then as we require core customers to purchase a certain amount that will increase the certainty for the marketers. And it's a chicken-and-egg question, you know.

COMMISSIONER McALLISTER: That's kind of why I asked, like the actual facilities on-site at the dairy, like collecting all the manure and the digesters and all that stuff.

MR. BROMSON: Yes. That will be -- most of those costs are covered by the funds that I discussed, and the costs that aren't will be covered by gas commodity sales.

COMMISSIONER McALLISTER: Okay. So they've got financing packages that are putting all that together.

MR. BROMSON: Yes. At least for these dairy biomethane projects, I think we're very comfortable that they're going to be up and running and selling gas within a couple of years or so.

But it does go through iterations. I mean the initial -- we've updated -- the figures I provided in terms of the gross amount of gas are updated figures, but they're pilots. I mean I think that some of the -- you have to have pilots and get projects in the ground.

COMMISSIONER McALLISTER: Yes, I'm not going to press you about, okay, so what's the overall, what's the percentage that we're going to displace, right? I mean I know that that's --

MR. BROMSON: Very low. You know, less than a tenth of a percent at the beginning.

COMMISSIONER McALLISTER: Well, I'd like to see sort of the definitive study of like, okay, if we cornered the market on biomolecules, what could we get, you know, and how much of it could be outside the LCFS, right, because right now that's kind of the main game in town.

So if we're going to talk about the gas system, we really need to kind of get to some numbers on that.

VICE CHAIR SCOTT: Can I just jump in here as well?

MR. BROMSON: Of course.

VICE CHAIR SCOTT: I mean one thing is under the previous administration there was a dairy digester working group that included Secretary Karen Ross and Richard Cory from ARB, Cliff Rechtschaffen and myself. And they did quite a bit of this work and information, and so it may be worth bringing some of that data in as well.

COMMISSIONER McALLISTER: I don't really see a whole lot of people talking about that work and so --

MR. BROMSON: Yeah, Commissioner Rechtschaffen is the presiding Commissioner --

COMMISSIONER McALLISTER: Okay. Right.

MR. BROMSON: -- over the diary biomethane and is still very engaged in it.

There have been various studies that have said 10 to 20 percent of California's gas used at a theoretical maximum could come from dairy and landfills and wastewater treatment plants. And that's a significant amount, and that is supposed to be both economic and obtainable hopefully by 2030 or soon thereafter.

COMMISSIONER McALLISTER: That's beyond California's orders too. That's going out into --

MR. BROMSON: Well, some would be but this is looking at in-state sources. Some of the procurement will be from out-of-state, and there's a big debate about how to credits that or not. I mean --

COMMISSIONER McALLISTER: Okay. Sorry.

MR. BROMSON: No, no. And you know at this stage -- and if you purchase renewable natural gas from outside the state you're not getting those molecules. It's being -- you'll get other gas molecules, but the gas will be used by somewhere. Even when you're purchasing renewable natural gas now, it's getting into the system, it's getting blended. It's not exactly what's used in cars, but it means it's getting used.

COMMISSIONER McALLISTER: Okay. So thanks.

One more question. I guess on the hydrogen front, how is the PUC looking at the issue of leakage? And I mean physical leakage, not market leakage. But sort of it's an even smaller molecule than methane. And if you've got a couple percent, give or take, of methane leakage, how does that translate into hydrogen leakage?

MR. BROMSON: I must admit I don't know. I do have a decent -- I mean the methane leakage is less than one percent. It's about half a percent I believe. And it's -- California, despite a lot of press and despite the problems we've had with the system, it's been fairly low and we've been -- but I honestly have no idea about the hydrogen.

COMMISSIONER McALLISTER: I mean the Stirling --

the only other major experience with hydrogen has been Stirling I think, and that didn't go that well. Part of the reason was that they couldn't keep the hydrogen contained. And so I would have similar concerns. I mean obviously it's a better infrastructure and, you know, existing infrastructure but I would have similar concerns. So we need to kind of get a handle on that.

MR. BROMSON: Will do. Thank you.

COMMISSIONER McALLISTER: Thanks very much. Really appreciate your being here and the partnership.

MR. BROMSON: You're welcome. It's a pleasure to be here. I'm a natural gas nerd, so this -- and people know that. So this type of presentation to me is my bread and butter.

COMMISSIONER McALLISTER: This is great. Well, we're missing former Chair Weisenmiller because he was deep, deep, deep into this stuff too. So we're having to kind of stretch our brains a little bit to pick it up.

MR. BROMSON: Well, thank you for your interest.

COMMISSIONER McALLISTER: Absolutely. Thanks a lot. Really appreciate it.

MS. RAITT: All right. So if Commissioners are ready, I think we can move on to public comment.

VICE CHAIR SCOTT: Great. I do not have any blue cards up here with me. I'm looking at our members of the public. I don't see anyone jumping up.

Do we have anybody on the WebEx?

Okay. So it appears there are no public comments.

I also do not have any closing remarks. I don't know whether you all do.

Okay. Well, thank you so much for the great presentations. And we're adjourned.

(The workshop was adjourned at 1:48 p.m.)

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