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CALIFORNIA ENERGY COMMISSION

STAFF WORKSHOP

In the Matter of:	) Docket No. 15-IEPR-03
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2015 Integrated Energy Policy	)
Report (2015 IEPR)	) RE: IEPR Commissioner
Standards	) Workshop on Preliminary
	) Natural Gas Outlook
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CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

ART ROSENFELD HEARING ROOM

SACRAMENTO, CALIFORNIA

THURSDAY, May 21, 2015

1:00 P.M.

Reported By: Peter Petty

APPEARANCES

Commissioners Present

Andrew McAllister, IEPR Lead Commissioner

Robert Weisenmiller, Chair CEC

Janea Scott, CEC Commissioner

Staff Present

Heather Raitt, IEPR Program Manager

Leon Brathwaite, Supply Analysis Office

Chris Kavalec, Energy Assessments Division

Peter Puglia, Supply Analysis Office

Anthony Dixon, Supply Analysis Office

Ivan Rhyne, Manager, Supply Analysis Office

I N D E X

P R O C E E D I N G S

MAY 21, 2015 1:04 P.M.

MS. RAITT: Good afternoon. Welcome to today's IEPR Commissioner Workshop on the Preliminary Natural Gas Outlook. I'm Heather Raitt, the Program Manager for the IEPR.

I will briefly go over the housekeeping items. The restrooms are in the atrium. A snack room is on the second floor. If there's an emergency and we need to evacuate the building, please follow the staff to Roosevelt Park, which is across the street diagonal to the building.

Today's workshop is being broadcast through our WebEx Conferencing System and parties should be aware that you're being recorded. We'll post an audio recording on the Energy Commission's website in a few days and a transcript in about a month.

At the end of the day today there'll be an opportunity for public comments and we're asking parties to limit comments to three minutes. We'll first take comments first from those in the room followed by our WebEx participants.

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

For phone-in only participants we'll open your lines after we hear from the WebEx participants.

If you haven't already, please sign in at the entrance to the hearing room. Materials for the meeting are available there. Comments on today's workshop are due June 4th and the notice explains the process for submitting comments.

And with that I'll turn it over to Commissioner McAllister.

COMMISSIONER MCALLISTER: Thank you, Heather.

So welcome everyone. As I think we can see by the size of the audience with us, this is a highly specialized topic. But that in no way means that it is not interesting. In fact, probably the opposite and I want to just iterate here that this -- we have some of the foremost experts in the country on natural gas and they help us develop our natural gas forecast.

And I always enjoy hearing Leon and Chris and the crew walk us through the issues, because they clearly have such a depth of knowledge. And it's very helpful to get that orientation and that update each time.

And also just to make sure that we're doing this in a way that provides access to the public. And I think that Ivan's team and the Commission broadly does that really, really well and I want to commend all of you on that.

Interesting time for natural gas in the state. We are paying increasingly close attention scrutinizing our carbon molecules in the state hoping that we can find ways for them to behave themselves. And making sure we do the accounting right such that we can meet our long-term carbon goals.

So natural gas, both at the power plant and at the end-use, we really need to make sure we've got our t's crossed and i's dotted and are being very intentional about how we talk about these and how we model and how we forecast. So in making our tools more and more capable each time and I think it's great that we have the alignment on those issues and that we really are able to bring the resources to bear on this topic.

I know Chair Weisenmiller has a special interest in this area as well (indiscernible) being the Lead Commissioner on natural gas. And I will pass the podium to him.

CHAIRMAN WEISENMILLER: Yes. Thanks, Commissioner McAllister, and thanks everyone who's here and particularly the staff for pulling this together.

Obviously the Natural Gas Price and Availability Forecast underlies a lot of our work. I think this year, Commissioner McAllister and I have been working on some of the new Building Standards. You know, that's certainly one of the key inputs there is indeed the price of natural gas, which is also a key input into the price of electricity. So that it's really important to get this right, so that when we are adopting Building Standards or adopting Appliance Standards that indeed, they are cost-effective.

And as Commissioner McAllister said, certainly more and more we're looking at greenhouse gas issues, carbon, sort of the Governor's goals. How that fits in certainly is going to push us to keep looking at and pushing the envelope on Energy Efficiency and cost-effectiveness there.

But again, this is one of the key building blocks is that in some respects this is a fairly esoteric topic. But it is really one of the more basic or more fundamental things that we do is price forecasting and then demand forecasting, both for electricity and natural gas.

COMMISSIONER MCALLISTER: Thank you again, for being here. And it's been very interesting, through the buildings parts of IEPR this year, we're sort of combining -- sort of taking advantage of the IEPR process to talk about end-use Assembly Bill 758, which is our existing buildings work.

And there's this growing sense that there's some

-- given the relatively low price of natural gas and the understanding that we need to move towards electrification over the long-term and some end-uses, particularly heating end-uses, that there's some sense that, "Well, there' a budding conflict there and if we're going to go for higher cost technologies that use clean electricity what does that really mean for our push towards Zero Net Energy and new construction and electrification of particular end-uses in the existing building stock.

And so that's actually I think a policy issue that's becoming more and more apparent that we have to engage and really put some resources on figuring out what the path forward is there.

You know, part of the Governor's Energy Efficiency Goal has been to clean up our heating fuels. And that pretty much either means electrify or use biogas. And so once question I think is the biogas future and what the scale and what the sort of supply chain and scale looks like on that front.

We heard the other day that the SoCalGas is estimating that they could get up to say 40 percent of their natural gas supply retail to be biogas. So let's unpack that at some point and figure out what that means for the forecast, for example. So anyway, bringing up some issues here; probably there's time for that as we move forward this afternoon.

I also want to welcome Commissioner Scott to the podium or to the dais and really appreciate your coming. And, you know, we're taking the baton from last year's update and we're running with it as best we can, so thanks for leaving us a good foundation. And I'll pass the microphone to you.

COMMISSIONER SCOTT: Excellent, thank you. I'm looking forward to seeing what information we have here today with our Preliminary Outlook, so glad to be here.

MS. RAITT: Okay. So our first speaker is Leon Brathwaite from the Energy Commission.

MR. BRATHWAITE: Good afternoon, Commissioners, members of the audience. My name is Leon Brathwaite. I work here at the Commission.

Today what I want to talk about is the preliminary results of our natural gas common cases. I want you to focus on the word "preliminary." There are quite a few things that we are still working on and we will be developing supervised cases. And these are due out in August of this year. So with that I'll get right into my presentation.

So what is the purpose of what we are doing here? Number one, I would like to tell you about the key elements of the natural gas model, how the model is run, I want to talk about the common cases themselves, what are the elements. And I also want to talk about the preliminary results -- underlying preliminary. And in that we're talking about demand, supply, prices, and any underlying trends that we (indiscernible).

On the demand side in the model we have five disaggregated sectors represented. Now, these sectors are: the Residential, the Commercial, Industrial, Power Generation and Transportation. In order for us to get our starting values for the demand side we have an offline operation that we do. And we use some independent variables to determine those starting values.

For example, the independent variables for the Power Generation is total electric generation, weather, natural gas prices, fuel oil price, renewable electricity generation and coal price. This is in the Power Generation sector. In the other sectors we have other independent variables that give us our starting values.

The one thing I want you to note in Transportation, these factors, the independent variables for Transportation are applied only outside California. The in-state data is supplied to us by our Transportation Office.

Also, from this regression work that we do we get some elasticities in each one of the sectors. The range of elasticities that we are using in this forecast, in this process, is 0.53 to about 1.34.

On the supply side we have what we call Supply Cost Curves. Now, this particular curve you are looking at is not represented any way in the model. What you're really seeing here is an aggregation of 400 plus curves that we presently have in the model. And you can see that this curve is moving to the right, starting in 2007 going all the way to 2015, our current year.

The reason for that is that technology have lowered costs and made natural gas supplies more abundant. Keep in mind, during this time we are using somewhere between 21 and 23 Tcf, yet our curve is moving to the right. This tells us something about the abundance of natural gas.

This here is a simplified view of our model. You may hear me use the word NAMGas. It is really an acronym for North American Market Gas-trade Model. So the simplified view is this: we have natural gas supply basins connected to interstate and intrastate pipelines, which are then connected to our demand centers.

Now, we have this connection all over North America, Mexico, the United States, Canada. We put it all together, put data into our model, then the model iterates through all time periods and all regions. Our time periods that we are using on this particular forecast is between 2012 and 2015.

So the model iterates, from that we put estimates of supply, demand, and hub prices. We also generate burner-tip prices. Now, I will not be speaking any more about that, because my colleague, Peter Puglia -- I hope I'm pronouncing the name correctly -- will be speaking about that in a little while.

So we constructed three cases. We had a Mid Case, which I will be referring to as our Reference Case. We have a Low Energy Demand Case and we have a High Energy Demand Case.

The reason why we constructed these cases is because we wanted to coordinate with the other models here at the Commission. We wanted some consistency in the underlying assumptions. And as we go through this process we are trying to become more in-sync with the other offices.

So here are the key assumptions. Now, I have 13 lines here, but the 3 lines that I really want you to focus on is line number 6, line number 7 and line number 9.

The first of that is Coal Retirement. At my last presentation, which was I believe in February, the Chair raised this issue with us about Coal Retirements. So we went back, we had some discussions internally, we also consulted with some of our consultants and we came up with a profile of Coal Retirements. So we have in our High Demand Case, which in India we are calling that Aggressive Coal Retirements, we had 120 Gigawatts. In our Reference Case we are having 61 Gigawatts of retirements and in our Low Case we are having 31 Gigawatts of retirement.

The next item is the elasticities. Now, in the High Demand Case and in the Low Demand Case we turned off the elasticity in this particular set of runs. We hope to change that in our Revised Case. The reason why we did that was to keep consistency with the other models that we are using in this process, but as I said in the revised cases we hope to turn those elasticities back on.

The next thing is our Cost Environment. So we set our Cost Environment in the Reference Case at 1, we call it the average cost. That's based on historic data. And in the Low Demand Case, we have the Cost Environment there of 52 percent of the average of the Reference Case. And in the High Demand Case we have the Cost Environment there at 23 percent or 24 percent above the Reference Case values.

So now let us talk a little bit about the performance of the cases. This is where we get in some of the results and some of the trends that we are saying. So the first thing we look at is Henry Hub Prices. As you see, our High Demand Case results in our high price, which is the green line or the olive line. The Mid Case or Reference Case gives us the red line. And, of course, our Low Demand Case gives us the lowest price projection.

We also included that dotted line that looks at the historics and saw how it matched up with our projections. And if I may say so myself, it looks like the historic seems to match up really well with the projected forecast. I don't mean to pat myself too much on the back here, okay? Please don't take it that way.

So between 2018 and 2030 we are seeing growth in prices of about 2 percent. The 2030 price varies between about 3.60 in the Low Case to about 6.40 in the High Case per thousand cubic feet.

And around the 2016-2018 region we are seeing a sharp price rebound. That is really driven by demand growth that is going faster than supply.

U.S. Natural Gas Demand. Of course, we are seeing steady growth. If you look at all three cases we are seeing steady growth. Annual growth rate in the Reference Case is about 1.4 percent. By 2030 the U.S. demand surpasses 80 Bcf per day.

Now, we get to Power Generation and this is again, in the U.S. as a whole. So what is happening is that Aggressive Coal Retirements, which is what we did in our High Demand Case is generating that very large -- if I may point to it with the cursor -- that very large increase in demand that we are seeing right here after around 2021. Again, Coal Retirements is driving that. By the end of the forecast you can see that demand has surpassed 40 Bcf per day.

What about production? Well, in general we can say that the highest natural gas production is occurring in our Low Demand Case. The reason for that is that we have less imports from Canada and then we have lower -- the Lower 48 is more competitive with Canadian imports.

Now, in general the cost profiles in Canada is significantly lower than that in average in the Lower 48. So in cases where we become more competitive with Canada we're having less imports. So in the High Demand Case where the Lower 48 is in a high-cost environment we are having much more imports into the Lower 48.

We also decided that it might be worthwhile to see how we compare relative to EIA. Well, as you see in the schematic on the left, in general our prices are lower than that of EIA's. The reason for that is that if you look inside of both cases you will see that both productions, if you look at the supply resources that are available to satisfy the demands in these cases, the Energy Commission has much more -- some more supply resources to satisfy demand than is available in EIA's case. This has a price-lowering effect.

So what's happening in California? This, of course, is our point of major interest, so let's see what's going on there. So what we did, we looked at two important price points to California, Malin -- which is of course located in Oregon in the north -- and we looked at Topock, which of course is located in Arizona for their important price points to the state.

As you see the price trends here are very similar to that of Henry Hub. Growth rates are about the same. En points -- there is not much difference between the end points, which I'll talk about here shortly. But the trend, definitely the trend, is consistent with Henry Hub. We have some price differentials, which we will talk about right now.

So what we are seeing here are two things. Number one, with Topock the price differential is positive. And we are defining the price differential as the point of interest minus Henry Hub.

Now, in Malin we are seeing the reverse, we are seeing a negative differential. The reason for that, at Topock if you will look at a map of the United States and look at the development of production, in particular look at the development of shales, what you would notice --

nearly all of the shale development is occurring in the eastern part of the United States. What that is doing is having a lowering effect of prices in the east and not as much effect in the west. As a result we end up with a positive price differential.

As for Malin, there is another phenomena going on. At Malin, there are two major pipelines bringing gas to Malin. We have Ruby coming in from the east and we have GTN coming in from the north. These two pipelines deliver gas to California. And they are competing at Malin to see who will be the winner. As a result, we are seeing this major price differential on the negative side and we expect that to grow as we go into the future.

How about California natural gas demand? We are seeing that demand is being lowered in the early part of the forecast. When I say early part, up until around 2024, 2025, somewhere in there. And after that we are seeing a slight rebound in demand. The reason for that is that as we implement renewables generation it is suppressing demand. But once the renewables portfolio standard is fully implemented then we'll see this rise that we are seeing in demand at the end of the forecast.

So in general, we are seeing a decline of about .6 percent between 2015 and 2026. Overall, natural gas climbs to about 4.8 Bcf per day by 2030, but it still remains below the level of 2015.

How about for our generation? Well, that decline that I just spoke about is even more pronounced here. If you look at the demand in the Reference Case you can see the decline even more significantly than we saw on the previous slide. That, of course, is as a result of the implementation of our renewable portfolio standard. Of course, we are still seeing the growth at the end of the forecast. Once we have that full implementation the dramatic effect that we had seen previously seems to disappear a little bit, not totally but a little bit.

Now, if you can look at the Supply Portfolio for California, we chose the year 2025 to do this. We could have chosen any year we wish, I just chose 2025 at random. I don't know. Now in this graph you will see that blue edge and that is Malin. Now Malin includes two items. Malin includes gas flows that come along Ruby and gas flows that come along GTN from the north.

So what we are seeing here as you go through the cases, as you go from left to right, the greatest variation in terms of supplying California is occurring at Malin. So we could infer that Malin is our marginal supplier. This graph demonstrates the effects of our different sources of supply that come into the state.

One of the things you'll also notice here, that the share provided by instate production is not changing very much. Well, of course, California is not developing any new resources. And that value will not change unless our development instate changes, so we are seeing this relatively constant value. As you know, right now instate production is declining and declining significantly and it does so in all three cases.

So what are my conclusions? Number one, U.S. natural gas demand grows at a rate of about 1.4 percent between 2015 and 2030. It reaches 85.2 Bcf per day in the Reference case by 2030.

The implementation of renewable generation suppresses California’s natural gas demand, declining at an annual rate of about .6 percent between 2015 and 2026. Overall demand reaches 5.8 Bcf per day by 2030, but it remains below the level of 2015. And I think I showed this previously.

Henry Hub prices rises to about $5.40 by 2030. That's a growth rate of about 1.8 percent between 2017 and 2030.

Aggressive Coal Retirements outside of California contribute to higher natural gas demand and to higher prices. And the reason why I say outside of California is because we do not have very much coal to retire here within the state.

California’s share of the supply portfolio remains relatively constant, relatively unchanged across cases, but of course instate production is declining and is declining significantly in all three cases.

Malin, which displays the greatest fluctuations across the cases, is or could be inferred that it is our marginal supplier.

So what are the next steps? We, of course, will continue our investigation of Coal Retirements. As I told you this was an issue that the Chair raised with us and we had some discussion internal to the Commission, and we had some discussion with some of our consultants outside. And we made some changes and we will continue our work in that regard.

We will look at the demand on demand and look at the impact on prices.

We will also further investigate the Renewable Portfolio Standard and we will incorporate anything that comes out from the U.S. EPA.

We'll incorporate data from our Demand Analysis Office and our Transportation Office. We didn't have that data to available to us for this set of runs, but we certainly will have them available in the revised cases and they will be incorporated.

We will be examining the Canadian supply cost curves. Now, this is a relatively large issue, because those supply cost curves determine the amount of flows that come into the Lower 48. We want to make sure that those costs are robust and representative of what is actually happening. So we will be looking at that a little more closely.

Once we have done all of these things, and we will do them, we will develop and produce the revised cases. And that is scheduled for completion in August of this year.

COMMISSIONER MCALLISTER: Hey, Leon? You had a couple of issues there where you were going to work with the EPA or get more information from EPA. Is that related to 111(d) or something else?

MR. BRATHWAITE: Yes, it is, Commissioner. Yes, it is.

COMMISSIONER MCALLISTER: Okay. So is that just a matter of figuring out -- well I guess, how is that relevant for the forecast itself for California? How's it relevant beyond just sort of what California's compliance with 111(d) might look like?

MR. BRATHWAITE: Well, you know, even though we have no Coal Retirements to speak about here in California, but Coal Retirements that are occurring outside the state does affect us in this manner.

If we have, say let's go back to the Aggressive Case that I just spoke about, if we have that say aggressive amount of Coal Retirements actually occurring that will certainly raise prices. And if that raises prices yes, we will feel it here in California. And I'm showing you the trends that compare, when you looked at Topock or you look at Malin compared to Henry Hub, which is in Louisiana. I show you how similar those trends are looking. So yes, Coal Retirements, we do not have any within the state, but we certainly will be affected by anything that happens outside the state.

COMMISSIONER MCALLISTER: Okay. I've got it. And then is it a similar sort flip side for that same issue for the RPS.

MR. BRATHWAITE: Indeed sir, yes.

COMMISSIONER MCALLISTER: Okay. Yeah, okay. Thanks.

CHAIRMAN WEISENMILLER: Now, I think on renewables we really have to reflect the Governor's Greenhouse Gas Goals. And so we're really talking about getting 50 percent renewables by 2030 --

MR. BRATHWAITE: By 2030, yes.

CHAIRMAN WEISENMILLER: I think also we have to take into account in terms of the Southern California, the air quality regimes. Requirements are likely to come in and certainly we should really connect first to SoCalGas and triangulate with them, Edison and ARB. But certainly what I generally hear from the South Coast Air Quality Management District is that it's going to be very, very difficult to meet the EPA requirements, because of the Clean Air Act in SoCal and San Joaquin. And then we may have to be moving to a post-combustion world down there. And so again, I think we could see major impacts.

There's also the other thing that could affect gas demands is gas for goods movement. But I think in terms of trying to reflect sort of the impending changes there it would be very important looking forward, which will certainly affect the demand for gas. And will come back and affect the price.

I guess looking at the price side of stuff, one of the questions is how much -- we have procurement and then we have distribution. And obviously at this point there's a lot of investments going on in the gas distribution system in terms of reducing leakage and increasing safety.

MR. BRATHWAITE: True.

CHAIRMAN WEISENMILLER: And so trying to build those in on the prices will be important, which probably means presumably we are connecting to the PUC on the gas price forecasting. But that will be very important to do those connections. We could be looking at higher cost for safety and less (indiscernible) and that certainly will have impacts on costs, which to the extent we need to really be using this for setting our Building Standards and Appliances and a lot of that.

So we have to use the numbers right, which means we need to reflect those changes.

COMMISSIONER MCALLISTER: In particular, I would just -- absolutely, those are fantastic points. And in particular on any influence that's going to push prices up really we need to try to anticipate that.

MR. BRATHWAITE: True.

COMMISSIONER MCALLISTER: Well, for any number of reasons, but we just want to get it right, but also sort of the relative difference between electricity and natural gas in terms of price really does exacerbate that difference in policy pathways that I was talking about before.

So if it's actually not so drastic or if the discontinuity between gas and electricity isn't as big, then that's really helpful to know as well. So any forward thinking we can do and work with the PUC on where they think things might be going would be really good to incorporate.

MR. BRATHWAITE: Commissioners, I can assure that as we go through this process all information that we get whether it's from the CPUC, whether it's from the EPA, whether it's from things that are going down in the southern part of the state, we will try our best, as best as we can, to incorporate that into our work.

MR. BRATHWAITE: Yeah, I wonder -- well we have a reliability, Southern California Reliability Workshop down there. And I think having Barry Wallerstein hopefully on the dais there will help us build a record and maybe we can tee up some of these issues there to sort of get a second bite. Get another bite at the apple and talk whatever issues through that we need to then.

CHAIRMAN WEISENMILLER: And certainly encourage all of the stakeholders to -- you know, when you do your written filings address some of these questions and help us get the best thinking we can on these questions.

I guess the other one, which -- so my anticipation is there's not much in the way of fracking in terms of gas production in California. But, you know, certainly that's a big issue and I would anticipate tighter and tighter regulations in California on fracking when the study is done by the Department of Oil and Gas.

MR. BRATHWAITE: Right, right. Well, the Department of Oil and Gas is supposed to come out with some regulations here in the near future. So whatever impact that will have upon any development or any potential development, I'm sure it will be quite evident and certainly we will incorporate that in any work that we are doing.

COMMISSIONER MCALLISTER: So before I just want to make sure this sort of gets a task going forward on the renewable gas front. You know, I think there are quite a few complete sort of different claims about what the future looks like. And I think it'd be really good to get -- to create the foundation, sort of a good analytical foundation, and a good sort of documentary record about the biogas future.

MR. BRATHWAITE: Yes.

COMMISSIONER MCALLISTER: And it's really -- you know, if the top end is 40 percent what are the scenarios that are most likely in there -- I think would be really helpful to project.

MR. BRATHWAITE: Well, in this set of runs we did the mandate incorporated, which is 33 percent by 2020. We understand the Governor has since produced an executive order about having 50 percent by 2030. And we certainly will be doing scenarios on different sort of sensitivities to look at just that requirement or any of the biomass -- some of the other biomasses uses that will be taken into consideration also.

COMMISSIONER MCALLISTER: I guess really it's more than just the Renewable Portfolio Standard, but just the idea that the gas distribution utilities are going to have to be offering a mix of product that includes a much heavier proportion of biogas in order to make that end-use, you know, sort of -- in order to decrease -- mitigate the impacts of combustion of gas generally, right?

MR. BRATHWAITE: Right, sure.

COMMISSIONER MCALLISTER: So really this is across the board, not just with respect to power plants and RPS, but end-uses of all sorts. So the forecast should try to include as much of that as possible.

CHAIRMAN WEISENMILLER: Yeah, I think if you look at the E3 PATHWAY Study that was done as part of the development of the Governor's Greenhouse Gas Goals it has some scenarios looking at basically the development of biogas and using that more in the system. And one of the things which we really struggled with in that work was how much biogas would be used for power. How much it would be used for transportation and what were some of the limits.

One of the studies we found, which I had some difficulty personally with, was that a lot of biogas would be imported into California going forward. So again, there's certainly a lot of very interesting work that frames some of the questions. But again, as you try to deal with basic gas supply and demand and what that means for prices, then certainly the lower the demand and the more the supplies, then the lower the price.

MR. BRATHWAITE: Sure, yes. Indeed.

COMMISSIONER MCALLISTER: And there's no need to go into some of the statutory issues there, the high-level scenarios. I mean, you know, there are other forums that I think we would discuss things like contractual details for importing biogas from Louisiana or whatever those might be. You don't have to concern yourself with those, but certainly the mix of supply in some scenarios would be really helpful.

MR. BRATHWAITE: Indeed. Indeed and I can assure you, sir, that we will be taking as much as we can. I mean, we are modeling and we have some broad definitions in there. But we certainly will take as much as we can into consideration and incorporate where possible (indiscernible) scenario sensitivities or anything like that, that ran, to speak to any of the concerns raised by the Commissioners.

COMMISSIONER MCALLISTER: Great, thanks.

MR. BRATHWAITE: Sure. Okay. Thank you very much.

MS. RAITT: Next is Chris Kavalec from the Energy Commission.

MR. KAVALEC: Good afternoon. I'm Chris Kavalec from the Energy Assessments Division.

I will be talking today about our End-User Natural Gas Forecast for California. We in the Demand Office are better known for our Electricity Demand Forecast, but whenever we undertake an Electricity Demand Forecast we also, at the same time, produce an End-User Natural Gas Forecast using the same models and techniques and so on. And we use the same sectors listed here that we do for electricity.

And we also, on the Electricity side we get an EV Forecast from our Transportation Unit. On the Natural Gas side we get a Natural Gas Vehicle Forecast from that unit.

Separate models, as in the case of Electricity for each sector. And Leon alluded to three demand cases. We have a High, Mid and Low where our key inputs are varied like economic/demographic growth and prices.

I have weather listed here. We incorporate potential climate change on natural gas demand by employing scenarios, temperature scenarios provided to us from the Scripps Institute of Oceanography. And we convert those temperature scenarios into changes in heating degree days, which affect natural gas demand.

When we forecast, we forecast for four planning areas: the three IOUs and then all the other little ones combined into “other.”

We incorporate Building and Appliance Standards within our residential and commercial end-use models. And by end-use model I mean these are models that operate from the ground up at the house level on the residential side and the square footage level on the commercial side.

Also utility incentive programs, in our forecast in 2014 we have about 200 million therms of estimated savings from efficiency programs, which decays to about 100 million therms by the end of the forecast period.

And I mentioned the climate change and a lot of talk about the drought. We have rainfall incorporated as driver in our agricultural sector and more about that in a minute.

This is a summary of our Forecast Structure. We have our sector models and those results are transferred to our summary model where the results are aggregated and weather adjusted and calibrated to actual consumption. Peak model there not relevant for the natural gas side and that provides us our annual Natural Gas End-User Forecast.

And here's what our latest forecasts, Preliminary CED 2015 we're calling it, looks like at the statewide level. The three scenarios at the top there and then in red we have the Mid Case Forecast from the 2013 Forecast. And you'll notice we start off at a higher point and that's because consumption in 2013 of end-user natural gas or end-user consumption was higher than we had prediction in 2012, so we start off at a higher point.

You notice the 2013 Forecast is pretty flat and that would've been the case in this forecast as well except we have projected a large increase in natural gas used by medium and heavy-duty trucks from our Transportation Unit.

So I've asked Bob McBride from our Transportation Unit to be here in case there are any questions about the Natural Gas Vehicle Forecast. Otherwise the Transportation folks will be having a workshop in June where they will go into detail about their forecast including natural gas vehicles.

And here's what it looks like for natural gas vehicles. You see a very large increase from around 100 million therms all the way to above a billion therms.

Taking a look at growth by planning area for the three IOUs, at the top there you'll notice SoCalGas has the lowest growth rate of the three. And that's because a lot of their natural gas usage comes from resource extraction, meaning gas and oil extraction. And that sector is projected to continue to decline in importance. And therefore that has a negative effect on SoCalGas, more than the other two IOUs, because that's a bigger sector in Southern California.

Looking at it by sector, the impact of decline in the resource extraction sector is also reflected for industrial. The Industrial Forecast, which is negative. Residential is flat and one of the big reasons for that is that there are very few end-uses on the residential side. And most of them have been addressed by our Building and Appliance Standards. More end-uses on the Commercial side, less percentage-wise addressed by standards, a little bit of growth in the commercial sector, around 3 quarters of 1 percent.

COMMISSIONER MCALLISTER: Hey Chris, where is that growth probably coming from? Is that just square footage growth or is there some other driver?

MR. KAVALEC: Yeah, it's basically coming from square footage and on the residential side from increase in the number of homes, but you don't have the Standards impact on the commercial side as it grows as you do on the residential side. So that's why you have more growth.

COMMISSIONER SCOTT: Chris, do the numbers from the previous slide -- the consumption from transportation -- I mean, does that also translate itself into a percentage that you could include here, so that you've got the Residential, Commercial, Industrial and then maybe there'd be a Transport one there as well?

MR. KAVALEC: Yes, I could do that and that would, of course, be by far the biggest since we're increasing by a factor of ten over the forecast period.

COMMISSIONER SCOTT: Right.

CHAIRMAN WEISENMILLER: Chris, I just had one question on the impacts of reduced oil and gas production. You know, that one of our major areas is Kern County. Obviously there's some like Long Beach, some within the L.A. Basin area, but Kern County has a really complicated split between the two utilities for gas service. In fact, there was one period of time where the two of them were in a war on who could basically serve specific customer. So I would be anticipating PG&E would also see some impacts in this portion of the Kern County load?

MR. KAVALEC: Yeah, and they're -- I don't have it here, but their Industrial Forecast is the lowest of the three sectors. I don't have it listed here, but yeah.

CHAIRMAN WEISENMILLER: Okay. Good. Okay, thanks.

MR. KAVALEC: Okay. I mentioned climate change. We get scenarios from Scripps and we developed a scenario with relatively high increases in maximum temperatures among their scenarios of which there are 12 to 15. And for our Mid Case we used a temperature increase roughly in the middle in those scenarios.

What ended up happening though was although in the High Demand Case we had higher maximum temperature increases. In the Mid Demand Case we had much higher increases in minimum temperatures. The result of that was that heating degree days decreased by more in the Mid Demand Case than it did in the High Demand Case. And you see the results here, that the consumption decrease -- where this is a decrease in heating degree days -- is higher in the Mid Demand Case than it is in the High Demand Case.

COMMISSIONER MCALLISTER: So, let's see I'm going to ask something that also has to do with Electricity Forecast, but it sort of seems like those are flip sides of one for the other, right? You've got sort of your extreme case on the cooling side would be high temperatures, which would be less -- you know, fewer heating degree days, right? So you have more cooling degree days, fewer heating degree days.

In the overall sort of integrated Forecast where we're laying all these forecasts side to side and sort of trying to make them internally consistent, I'm assuming you would pick the right scenarios to go together in the overall package?

MR. KAVALEC: Yeah, and that's a good question, because we have typically just taken the scenarios and said, "Okay, here's one roughly in the middle temperature-wise. Here's one towards the end. This will be our high, this will be our mid." But you end up sometimes with what we have in this case with a larger increase in minimum temperatures and something in the Mid Case. So what I'm planning to do is to talk to Scripps about developing a distribution, so we can have something more consistent in our scenarios.

What happened on the Electricity side is because of there was such a large increase in minimum temperatures and reduction in heating degree days you get very little impact on electricity consumption in the Mid Case from climate change, much higher in the High Case.

COMMISSIONER MCALLISTER: High consumption, right. Okay.

MR. KAVALEC: Anyway, my point is to avoid this sort of issue in the future we can hopefully develop some sort of consistent distribution we can use instead of just picking individual scenarios.

COMMISSIONER MCALLISTER: Yeah, I guess that's a question kind of about the interagency discussion too. Sort of when we're working through and when we're discussing the scenarios, it doesn't seem right to sort of say, "Okay, well we have this (indiscernible) for natural gas discussion, what do we think the most likely scenario is there?" And then have a completely separate discussion about electricity. What's the likely scenario there?

Well, if we go with the -- maybe if we go with Mid both scenarios then it just doesn't become that big of an issue. But the sort of high-heating and high-AC scenarios kind of don't go together naturally, right? So we kind of need to integrate that discussion across the two fields and probably for other reasons as well. But I think a distribution might get us partway there and then we just have to be intentional about what overall scenario we're picking. And then make sure that we have the right -- in each fuel sector we have the right implications build it, right?

MR. KAVALEC: And we have had discussions on those scenarios, not specifically about climate change, but the point I always try to make is you can never make everything consistent.

COMMISSIONER MCALLISTER: Yeah, yeah. Well, and a distribution would get us some of that. So I think that's a good move.

MR. KAVALEC: Yeah, we'll always have some inconsistencies.

CHAIRMAN WEISENMILLER: Yeah, the other thing I was going to point to is a recent paper by Michael Mann and Peter Click. And they looked at western climate and they do a distribution of temperatures and hydro. And they find a strong correlation between a very hot climate in

California and very dry. And so again, I'll pass that on to you as we should docket it.

But again, as you look at the gas and electric interactions, certainly indeed when it's hot it's also dry. That has implications on certainly the power system too.

COMMISSIONER MCALLISTER: Absolutely. And then to the extent climate change produces a broader distribution part of the impact may not even be so much an average as just the width of the distribution, in which case you're going to capture a lot of scenarios when you go that route. So the sort of diversity impact I think is important to capture in there.

MR. KAVALEC: Yes.

Okay. Just for fun I looked at the impact of continued drought on the agricultural sector natural sector use, which I guess is mainly for irrigation purposes. So you have this inverse relationship between rainfall and natural gas usage in the agricultural sector. So I have the red line labeled the "continued drought" case here. And just assume that rainfall in inches continued as the average of the last three years. Rather than in the base case we assumed a 30-year average for rainfall.

And you see the difference here, around 9 million therms by the end of the forecast period. Not a huge amount, but it is 6 to 7 percent of the sector's use.

Okay. So next for us we will, of course, be doing a revised forecast in the fall where we will incorporate yours and stakeholders comments, updating historical consumption, that's always important. We're not able to update to 2014 for the preliminary forecast in terms of consumption data. We will do that for the revised forecast. Of course, we'll update our econ-demo and natural gas prices from Leon.

And the big thing probably is we will have another round of additional achievable energy efficiency from the CPUC potential study that's going on right now. And that will be incorporated in both our End-User Natural Gas and Electricity Demand Forecast.

COMMISSIONER MCALLISTER: Hey Chris, what's kind of the kind of timeframe for that? I mean, I know we always find ourselves crunched at the end of the year and kind of have to bleed over into the following year. And that's in order to get the summer into the analysis. Is that kind of generally the case now, you think, the same as it ever was or is there some new effort to kind of get the timeline in order?

MR. KAVALEC: Yeah, we are, in fact, going to start the process specifically for AAEE within the potential study in June as soon as we finish the Preliminary Forecast.

COMMISSIONER MCALLISTER: Oh, great. Okay.

MR. KAVALEC: And I think as I mentioned before, or in our Electricity Demand Assumptions Workshop we're pushing the revised forecast back to December, so that we can incorporate the summer loads in the forecast.

COMMISSIONER MCALLISTER: Right, okay.

MR. KAVALEC: So that, I believe, gives us plenty of time to analyze and incorporate the AAEE savings.

COMMISSIONER MCALLISTER: Okay, great. And this is Navigant who's doing the work for --

MR. KAVALEC: This is Navigant, yeah.

COMMISSIONER MCALLISTER: Okay. So we have to wait to really bring it home for that output.

MR. KAVALEC: Right, but as I said Navigant is specifically focusing on AAEE as starting in June.

COMMISSIONER MCALLISTER: Okay, great. That's good, thanks.

MR. KAVALEC: Okay. Thank you.

COMMISSIONER MCALLISTER: Thanks, Chris.

MS. RAITT: Next is Peter Puglia.

MR. PUGLIA: Good afternoon Commissioners, and members of the audience. Thank you for your time. My name is Peter Puglia and I am an analyst in the Natural Gas Unit and Supply Analysis Office here at the Commission.

I have a presentation that is not controversial.

I'm going to be talking about a tool that is used to produce controversial things like forecasts of prices. You can't yell at me.

COMMISSIONER MCALLISTER: Well, we often find that things we think are non-controversial turn out to be really controversial. That's kind of hard to predict, right?

MR. PUGLIA: I've been forewarned. Thank you, Commissioner McAllister.

I'm here to talk about the Burner Tip Natural Gas Price Model, which has been out for -- the first version was posted to our website November of 2013, but it's been in development for almost four years. It's high time to talk about how it works, the underlying data, the references to the theoretical considerations that go behind it, because it's gained currency with individuals, analysts, grid planners. Not just here in California at the ISO, one of the IOUs I've had repeated contacts about it, but also in the WECC. So I'm going to walk through exactly what it does, why it does it, and some of the background of that model.

Okay. An important distinction -- the purpose of the Burner Tip Model is to do what the NAMGas Model estimates does not do. Leon was talking a half-an-hour or 40 minutes ago about the prices, the supply demand estimates that the NAMGas Model produces. Those are values that are estimated not at anybody's Burner Tip. Not in Residential, Commercial, Industrial or Power Gen sectors. Those are values for supply, demand and price at any one of the NAMGas hubs across North America. The Burner Tip Price Model takes as its principal input, the output from the NAMGas Model and calculates to account for the cost of taking the gas at the NAMGas hub and moving it to power plants across the Western Interconnect.

So what it's doing is it's providing a plausible estimate of proprietary natural gas prices that electric generators pay, not in the future, but assuming future conditions in of course the 2015 IEPR Common Case scenarios, because it's principal input is the output from the NAMGas Common Case scenarios.

Natural gas prices are critical for modeling electric resources. Planners, grid operators and investors need plausible price estimates. Planners for modeling and siting resources, grid operators for reliability and stability and investors because if you're going to put down a lot of money to site a power plant, even if it's not natural gas-fired, you need to know what the cost is going to be or what the cross-substitutional cost is going to be. If gas is so cheap that it might dispatch over some other fuel.

So that makes the Burner Tip Natural Gas Price Model a bridge between the NAMGas and the PLEXOS models. And because it uses as its principal input the NAMGas Model outputs it has gained currency for being able to provide a set of plausible estimates of the price of gas given those conditions -- a high reference and the low cases in the 2015 IEPR Natural Gas Outlook.

For that reason we use it here as an input into PLEXOS to simulate electric grid resources dispatched in the WECC.

Now there are 13 price hubs in California, there are 61 price hubs in the WECC in the NAMGas Model. The Burner Tip Price Model picks out 24 of those as the best fitting hubs to estimate prices at approximate natural gas-fired power plants in the Western Interconnect.

They're not always the closest, but the distance relationship is correlated strongly with the cost of getting the gas through a pipeline, right? The longer -- some pipelines like Gas Transmission North, which comes out from Canada uses a postage stamp rate. Whatever distance you're sending it is the price you pay. It doesn't matter what the distance is, most interstate pipelines charge by distance. So this is a reasonable assumption to use.

We include the Malin, PG&E Citygate, Topock, Arizona which is the most liquid of the Southern California incoming interstate natural gas pipeline meters. We also use Malin, which is the big pipeline junction at Malin, Oregon where the Ruby Pipeline comes in from the North Rocky Mountains and Gas Transmission North comes down from Canada. Two major pipelines meet at Malin and then feed into PG&E's Redwood Path, which are lines 400 and 401. These are liquid, meaning lots of transactions for gas are based on those hubs.

Okay. We also assume the reality, which is that generator aren't going to be paying firm prices. Other marketers will buy firm capacity on pipelines and they'll assume some of the risk to sell at a particular discount to electric generators. But the model tries to accommodate that by assuming that most of the capacity's interruptible, which the generators are paying.

The capacity to move the gas they buy, which is a separate charge, which the NAMGas Model estimates. That capacity price is pretty much close to the interruptible rate. It is also a function of capacity release markets, how much is the pipeline subscribed? If the interstate pipeline is heavily subscribed, it is heavily trafficked, it is full much of the time, then you're going to get closer to the interruptible rate. You could have a discount from that if the pipeline is undersubscribed. It's trying to reflect the reality, but again it's modeling that.

Oh, I forgot to mention, if you look in the report that we have posted on our website it has a history of transportation rates, the capacity costs that you have to pay in the pipeline tariffs. And they are up and down and up and down and up and down. There isn't any pattern, either linear or second order, so we just assume that the capacity prices in the tariffs extended out into the future for the Burner Tip price all are flat. Whatever they are this year or whatever they're going to be next year, until we open up the tariffs and find whatever they've changed -- and then I go in and I change those capacity prices in the model.

We've elected Henry Hub as the best choice to calculate seasonal factors. That has been an issue of debate with other grid planners outside of the Commission. We've chosen it, because it's a pricing point for the New York Mercantile Exchange, gas futures contracts, intercontinental exchange, over-the-counter swaps. The difference that we had with other grid planners had to do with a very reasonable expectation that instead of using Henry Hub Louisiana, if we used a set of hubs that were spread across the Western Interconnect we would probably get seasonal factors to adjust, to take the annual NAMGas price. And turn it into 12 seasonally-adjusted prices that would be more reflective of what you see in the Western Interconnect than just using a single set of 12 factors that were derived from historical Henry Hub prices.

The statistical tests that we did about a year ago showed that there wasn't any difference. And one of the major reasons is that, of course, you're taking an annual gas price and you're turning it into a monthly price a lot of what is going into that change in the price from month to month is the weather. Chris talked about that in his presentation and that's the case.

The reason a hub like Henry Hub in Southern Louisiana, which is -- I lived down there -- it seems like it's not really representative, but there are nine interstate pipelines that run through Henry Hub that extend up to -- two of them extend up into Illinois. One of them, Transcontinental Pipeline, is 42 inches wide; it goes all the way out to New York City. Two pipelines extend all the way across to Florida. So there is a lot of gas moving through Henry Hub where the transactions on that gas reflect markets everywhere east of the Mississippi River. And that's part of the reason why Henry Hub works so well for modeling our seasonal factors.

We also needed it, because we're taking the NAMGas prices and we're turning them into monthly prices. We had to take one annual price up here and the next year's price, which is here from the NAMGas Model in each of the three scenarios. And we had to turn them in monthly prices without some kind of a big break between the two years. We discovered that if we dropped the traditional January to December year and we went instead with June to May we found that the discontinuities go away. We get a difference between the Burner Tip Model's estimated price and the actual price and the actual price in a backcast that was smaller than if we had stuck with the traditional January to December factor.

And the biggest reason is that the June seasonal factor in any one of the samples we've used: the 5-year Henry Hub historical set of prices, the 10-year or 20-year the June seasonal factor is closest to 1. And so that is going to be multiplied by that set of factors. If your factor's closest to 1 and you set your year break May to June, your discontinuity goes down to what it actually was between the two years divided by 12.

Does that make sense?

Okay. And the pseudo-code that I'll help you walk through -- I'm going to get into the actual mechanics now. And in my first degree in physics I was warned at Santa Cruz that you either do the problems or you won't know anything by reading a book. So doing the calculation again and again and again until 4:00 o'clock in the morning is the only way I learned anything. And it is part of my pedagogy in this case.

The Burner Tip Price, very simply is the commodity price from the NAMGas model for the three scenarios plus the pipeline cost. What you have to pay the interstate pipeline or if it goes into Southern California what you'll have to pay SoCalGas to get it to the power plant burner tip. The commodity price within that equation is the seasonal factor times the Triple A price and I don't want to walk -- you can read English for yourselves.

The one point of no transparency is you'll see under the seasonal factor that it's derived from NGI Henry Hub Bidweek Survey. That's natural gas intelligence. We pay these people in Virginia to do a survey of the monthly bidweek survey of natural gas prices that are traded at Henry Hub, because we found that that's the closest thing to the general reference equilibrium price for a power generation gas contract.

So now I'm going to get into a less abstract and even more mechanical going from pseudo-code towards a machine language of how the Natural Gas Burner Tip Price Model works. The variables that you see that are highlighted in red are described on this slide. The variables that you see in red on the next slide are described on that slide, okay?

And again, all of this is publicly available information except for the NGI, which is the Natural Gas Intelligence Bidweek price.

And this is an example for an October Burner Tip Price. Now, this is the very end, this is the machine language dead-end here.

If you open up the currently posted Natural Gas Burner Tip Price Model on our website -- I'll have a link for you at the very end where you can find that -- and you open up the October 2020 SoCalGas price, which is at Topock, Arizona-Needles, California Hub -- the Burner Tip Price Hub there -- you'll see that the price is $6.06. You'll see that the seasonal factor is 0.9304 and that is the median of the 2009 through 2014 -- you'll see them all in a row there -- 2009 through 2014 Henry Hub average ratio of monthly price for October over the entire year, okay?

So I've shown how that seasonal factor is worked out for the factor we use. I gave another example, 0.9310 is similarly calculated -- blah, blah, blah.

Finally, we get into the reality check. Why are people using this, why does the model produce prices that have a measure of plausibility that people find that there's value in it. Again, it relies heavily on the NAMGas Model, which allows a grid planner or investor or a policy maker to look at a plausible and coherent future world and make a judgment about how the power grid could react given those assumptions.

We have three common cases, three scenarios with their constituent assumptions, to simulate the gas price in the Western Interconnect. And a Computable General Equilibrium Model will do that without being influenced by history. Kimetric (phonetic) Models, they rely heavily on past values to populate their variables. They are -- the variables are populated by historical values.

We used historical gas prices and backcast validations. The WECC, if you look at the report in the appendix you'll see that there are some backcast validations that compare the prices that we would've gotten in previous years from the Burner Tip Price Model compared to these other entities.

And then finally where any forecaster would probably share a space with me in agreement, is that you have to run these prices, you have to populate a power grid model like PLEXOS with these prices. And you have to see under different conditions, what kind -- how does the power grid behave as a consequence?

And if you have a lot of experience as a power grid modeler you'll be able to see if the Natural Gas Burner Tip Price Model is a joke or if it actually gives you something that looks like resources are being dispatched closer to Southern California before they're being dispatched in West Texas.

With that I conclude my presentation. I'm available for your questions. Thank you.

COMMISSIONER MCALLISTER: Thanks very much, that was great. I think I'm good, actually.

MR. PUGLIA: Like I said it's all mechanical, no controversy.

COMMISSIONER MCALLISTER: You know, I didn't get you on the sort of pseudo-code to machine language analogy. I don't know if everybody else here did, but --

MR. PUGLIA: I apologize. It's computer programming.

COMMISSIONER MCALLISTER: Yeah, having different languages than that, yes.

MR. PUGLIA: Yeah, yeah. If you really care I'm sure somebody here could explain it.

COMMISSIONER MCALLISTER: No, no, it's fine. Thanks. Thanks a lot.

MS. RAITT: All right, next is Anthony Dixon.

MR. DIXON: All right, good afternoon everyone. I'm Anthony Dixon. I am here to talk about our Natural Gas Price Forecast Retrospective. This is looking at our past forecasts and using them to help look at our current forecast.

It is important to know that when you're forecasting natural gas prices there are so many factors, as you saw in Leon's presentation, that go into doing our forecast. There's a lot of things we can't account for. By doing these error bands we allow for a comparison of the current IEPR common cases to historical estimates. And help ensure that these are reasonable assumptions in us doing our due diligence as modelers.

These are the past forecasts that were used for this model and we were looking at these and going, "Well, we have all these predictions. How close were they to real numbers? How close were they to the actual Henry Hub numbers?" So to do that we looked at different statistical methods. And we looked at the mean absolute percent error, which is just a statistical method for determining the goodness of fit of past predictions to actual prices.

And so what we did is we took every forecast that we had done, we normalized them. And then we took the percent error between them and the actual Henry Hub prices, for all the models, and we came up with this.

And then we aligned each one for a year's forecast. And so the first year forecasted in each model is aligned, the second year or the third year and so on.

And then you take the average of those years, which is the bottom line here, of each one. Then we used

Excel to produce a linear equation using those mean absolute percent error averages. And apply that to our current IEPR common case, Mid Case. And this is what we came up with.

So these are more plausible Henry Hub price ranges for the preliminary IEPR cases for 2015. The plausible ranges in the error bands is much larger and encompasses more uncertainty than the common cases themselves do. The common cases right now capture only about 28 percent of the uncertainty implied by our historical error. And this error actually grows over time, because as you go out further and further in time you'll see you're getting more uncertain about what you're predicting.

And we do this because if someone were going to ask us, "What's the price going to be in 2016?" it would be unwise for us to just go, "Well, look at this. It says it's going to be 3.80." It's better if we were to look at it and go, "Well, the price is most likely going to be in a range between a high of $6 and on this floor a low of about $1.50." And we can say that with a lot more certainty that here is a price range.

And this goes on with a lot of forecasts when you see a -- they will forecast a certain amount. And say, "We'll plus or minus a certain amount of error," and this is what this is showing.

COMMISSIONER MCALLISTER: It would kind of be nice actually to -- let's see, well this is basically from here forward. But, you know, you're backcasting to all of these -- to the previous forecasts. It kind of makes sense that the further back you go the more off you are although sort of in the middle, you've got a year there if you go back a slide, what is it 2003 we were really off, right?

MR. DIXON: Yeah. Yeah, well these are not actually the -- this is the year forecast and so which --

COMMISSIONER MCALLISTER: Of the 2003 IEPR Forecast -- anyway, yeah.

MR. DIXON: Yeah, so this would be like the year 2003, this would be 2004.

COMMISSIONER MCALLISTER: Yeah, exactly. Exactly, that's what I'm saying, but we were -- you know, things took a u-turn and we were quite off shortly after that it looks like.

MR. DIXON: Yeah.

COMMISSIONER MCALLISTER: So I guess it'd be kind of nice to look at the actual prices that kind of overlay, say if we started in 1998, sort of prediction. You know, starting in year one and then finding some way to represent the actual price and then the evolution of actual prices during the ten years of that forecast.

And then that would -- because it seems to me that if you just look at this table you're saying, "Boy, the Energy Commission is just really way off." But there's been a huge wrench in the works, which is fracking and lower prices, which are kind of a, once in a generation if that, sort of thing going on.

MR. DIXON: Exactly and it's also --

COMMISSIONER MCALLISTER: So I don't think, you know, it's really fair to say, "Oh gosh, typically the Energy Commission is off." Only 28 percent of our forecast -- only 28 percent of variation is actually captured within the bands of our forecast scenarios, because I think there's -- for that historical period maybe that's the case. But if we look back further I'm sure the variation in price was nowhere near what it's been more recently. Or at least I would imagine, maybe Katie (phonetic) wants to take issue with that.

But every time is different and everything and ever time is unique. But I think that the particular technology evolution has been especially unique. So I don't want to necessarily, you know, go conclude that boy we've got to deal with 72 percent of complete unknowns going forward.

CHAIRMAN WEISENMILLER: I guess the one thing I'd like to know a little bit is whether there's systematic bias. I know that EIA was challenged at one point as always -- I think it was always over-forecasting. So but if it's -- basically if you're saying this is the balance and some of it's real high and some of it's real low, then again that is part of the nature of forecasting.

On the other hand if it's gee, we always over forecast or we always under forecast the price then that certainly would make us a little more -- getting back to the Standards it certainly would have implications on how we treat the forecast in setting Standards.

COMMISSIONER MCALLISTER: That's a really great point.

MR. DIXON: Yeah, these like I said are just the absolutes. They're where we were both up above and below. A previous version is we did it where we kind of took the high and the low and used those and it really kind of widened it more. I guess is what I'm saying.

COMMISSIONER MCALLISTER: I'm looking forward to that future where we get negative pricing down there, cross the zero boundary, that's really interesting.

MR. RYHNE: So my name is Ivan Rhyne and I manage the Supply Analysis Office. And Anthony undertook this project at my request. And some of the early work -- and we've pared down for the sake of brevity.

So what's interesting Commissioner McAllister, is that your request to sort of see that price evolution, we've done that in some earlier.

But Chair Weisenmiller, your question about bias -- what we saw is that there is not, at least given the price forecast we have, and I'll pause for a moment and sidebar -- these were all of the forecasts we could find that the Energy Commission had generated. And so that sort of fell within -- you know, in terms of going back and digging through historical articles -- if we could find more we would include those, certainly.

So we only have this sort of narrow window. I say narrow, but we're really starting in 1998, relatively narrow window of time in which to do that. So as technology has changed, as markets have changed, we've been off in some ways and can't see that. But what we do see is there is a -- there does seem to be a slight sort of imbalance between the high and the low-side forecast.

I think it's an excellent question and we'll go back and look. We think we tend to come out just a little bit on the low side in terms of that imbalance, but without I think further investigation that's about as far as I'd be willing to go. But there is just a little bit of an imbalance there.

COMMISSIONER MCALLISTER: I certainly don't mean to impugn the analysis. I think this is fantastic and really the kind of thing that we absolutely ought to be doing. And I want to make sure that we -- I mean, I think that keeping this alive over time will be great.

MR. DIXON: So along with this I also looked at what others are doing. And, of course, EIA does their own outlook and confidence intervals for natural gas prices. And theirs is incorporated in their short-term energy outlook.

A few differences with theirs and ours is they only cast out like 12 to 14 months where we're doing 13 plus years. They also, instead of using past forecasts, they use New York Mercantile Exchange future prices to do theirs. And they use much higher level statistical analysis, so when comparing our two together though it was very nice to see that we actually are somewhat close.

The dash lines are the staff's work and the solid lines is EIA's and as you can see on the slide here they are actually fairly close even though we did use vastly different methods to predict our values.

And other than that, any other questions? No?

(No audible response.)

COMMISSIONER MCALLISTER: I think we're good, thanks very much.

MS. RAITT: All right, if we're ready to go to Public Comment we can do that. Does anyone in the room have comments you'd like to make?

(No audible response.)

Anyone on WebEx?

(No audible response.)

Shall we open up the lines and just see if anyone on the phone -- so if you're on the phone, please mute our line and if you want to make a comment now is the time to go ahead and make a comment.

(No audible response.)

Hearing none, I don't think we have any public comments today.

COMMISSIONER MCALLISTER: Well, this is a very elite group evidently.

Let's see, so I'm really happy to see the steps forward here on the forecast and I think you're asking the right questions and doing the analyses as necessary.

And certain aspects of the natural gas world will have some chances in future workshops to -- we'll revisit this one down the road a little bit too. But we'll also have some future workshops to talk about issues that affect little sectors, parts of the natural gas sector like with transportation and more buildings end-use topics.

And I think that we should make sure the record is reflective overall of those conversations as well. Or that this analysis reflects those conversations as well.

But I'm happy with the Status Report and appreciate all the work.

There's obviously a real -- a huge reservoir of analytical work and resources behind the relatively pithy update that we get in a forum like this. But it's very much appreciated, all the work, so thanks to Ivan and the team for keeping it moving.

Oh, hey Ivan, yeah go ahead.

MR. RYHNE: Sorry, a closing thought sort of occurred to me. I wanted to emphasize that the work that has been presented here -- one of the keys that I don't know if it was emphasized earlier -- is that this is being done in coordination with all of the other modeling groups. And this is an extension of work that began last IEPR.

And I want to really extend my thanks both to the Demand Office, Chris Kavalec, and his team.

For the first time the End-Use Natural Gas Forecast, rather than being embedded and sort of hidden in its own subchapter in the Electricity Demand Forecast, is being featured in the Natural Gas Outlook Report and here in our Natural Gas Workshop as well as the Transportation.

Natural Gas numbers will be embedded in the Natural Gas Outlook although we will be discussing the Transportation Natural Gas Demand in the Transportation Workshop that'll be held in late June. But this is very much a coordinated effort and we appreciate all of the different teams who've put in.

And I think the interactive nature of this process actually speaks to the fact that we have three Commissioners on the dais for this very -- what would otherwise seem a very narrow and focused workshop. But in fact, we have a pretty broad spectrum of interests, because we cover a broad spectrum of topics.

So my thanks to the teams and especially to the Natural Gas team who put this together and also the IEPR team who really made things much easier on us to get here today, but thank you.

COMMISSIONER MCALLISTER: I definitely second that and thanks a lot, Ivan. And actually it didn't really -- thanks for tying up all the -- and emphasizing the integration that's happening across staff. Because I think -- and Chris's presence here today and the presentation I think sort of emphasizes that. I didn't quite fully pick up on that, so thanks for saying it explicitly.

And I agree that everything is related, right? And particularly as we go forward it's going to all become even more related and more granular geographically as well. So I think, you know, we all need to have our thinking caps on about how to do analyses that take all that future, that expected evolution into account in all of our energy systems, not just electricity.

So any closing comments?

(No audible response.)

All right, well I think we're adjourned. Thanks very much everybody.

(Whereupon, at 2:33 p.m., the workshop was adjourned)

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REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and

place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

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

IN WITNESS WHEREOF, I have hereunto set my hand this 8th day of June, 2015.

PETER PETTY
CER**D-493
Notary Public

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 8th day of June, 2015.

Myra Severtson
Certified Transcriber
AAERT No. CET**D-852