STATE OF CALIFORNIA – THE RESOURCES AGENCY
BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of,	)
	) Docket No. 13-IEP-K
	)
2013 Integrated Energy Policy	)
Report	)
(2013 IEPR)	)

IEPR Lead Commissioner

Natural Gas Issues, Trends, and Forecast Scenarios Workshop

California Energy Commission
1516 Ninth Street, Hearing Room A
Sacramento, California

Wednesday, July 17, 2013

10:12 A.M.

Reported by:

Kent Odell

APPEARANCES

Commissioners

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Staff

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Ivin Rhyne

Angela Tanghetti

Robert Kennedy

Peter Puglia

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Also Present (* Via WebEx)

Panelists

Dorothy Rothrock, California Manufacturers and Technology Association

Chris Ellsworth, Federal Energy Regulatory Commission

George Wayne, Kinder Morgan

Chris Fan, Pacific Gas & Electric

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Chuck White, Waste Management

Bevin Hong, Jr., TransCanada

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Public Comment

Tim Tutt, SMUD

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P R O C E E D I N G S

JULY 17, 2013 10:12 A.M.

MS. KOROSEC: All right, good morning everyone. Thanks for your patience. We're going to go ahead and get stared here.

I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit. And welcome to today's workshop on Natural Gas Issues, Trends, and Forecast Scenarios.

A couple of housekeeping items before we get started. Restrooms are in the atrium, which is out the double doors and to your left. Please be aware that the glass exit doors, near the restrooms, are for staff only and will trigger an alarm if you try to exit the building that way.

We have a snack room on the second floor, at the top of the stairs, in the atrium, under the white awning.

And we've also provided a list of restaurants, for the lunch hour, that are within walking distance of the building. You can pick that up on the table out in the foyer.

Please also be aware that lunch will be starting a little bit later than usual, probably about 12:30, depending on how the morning's discussions go.

And finally, if there’s an emergency and we need to evacuate the building, please follow the staff out of the building to the park that’s kiddie corner to the building, and wait there until we’re told that it’s safe to return.

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

We’ll make the audio recording available on our website in two or three days, and we’ll also post a written transcript in about two to three weeks.

We have time set aside for public comments at the end of the day today, at which point we’ll take comments first from those of you in the room, followed by those participating on our WebEx, and then the phone-in-only people.

For those of you that are in the room, please come up to the microphone at the center of the podium here so that we can make sure we capture your comments on the transcript.

And it’s also helpful if you can give our court reporter your business card, so we can make sure that your name and affiliation are spelled correctly.

For WebEx participants, you can use the chat function to tell our WebEx coordinator that you’d like to make a comment, open your line or relay your question at the appropriate time.

And for phone-in-only participants, we'll open all of the phone lines after we've taken comments from the people in the room and the WebEx participants.

And please, keep your phone line muted on your end unless you wish to speak so that we don't get any feedback on our end here.

We're also accepting written comments on today's topics until close of business July 31st.

And the notice for today's workshop, which is on the table with the handouts, and it's also posted on our website, explains the process for submitting comments to the IEPR docket.

So, now, I'll turn it over to Commissioner McAllister for opening remarks.

COMMISSIONER MC ALLISTER: Thank you all for coming to one in a substantial series of IEPR workshops. And even within this theme of natural gas it's really great to see the progress, and Ivin's team has really been working very hard to crank through all the analysis and make sure that we're getting feedback from the stakeholders at each step along the way.

So, I really commend them for that.

I want to -- I'm really interested in the discussion today and want to just really move on. But thank you all again for coming, and those of you on the web, as well.

You know, this is really -- this is really foundational stuff for California. Natural gas is obviously a bit of a hot topic these days for various reasons. But that doesn't change, in any way, the imperative to do the forecast in a way that's accountable, and open, and transparent. And, you know, deal with the challenges of the uncertainties in the marketplace today.

And so I really -- I think we're learning a lot during this period and I think Ivin and his team are doing a great job incorporating the kind of contextual realities that we have today.

So, having regular meetings with them, I've really learned a lot from this process, already, and I'm really looking to the presentations here at the panel, and the discussion afterwards.

So, thanks again for all of your work getting prepared, and I'll pass it off to Ivin.

MR. RHYNE: Thank you very much, Commissioner. I'll just bring up the presentation here.

All right, so there we go. So, good morning, my name is Ivin Rhyne. I'm the Manager for the Electricity

Analysis Office here at the Energy Commission, which is a part of the Electricity Supply Analysis Division.

This morning's workshop is actually being brought to you -- no, we're not doing the Sesame Street version, the Number 5 and the Letter K, no.

Well, it is being brought to you primarily, and really by the natural gas team, of which we've assembled a number of experts, also, to help us in terms of talking about this.

You will note that we will have changed a couple of presentations in the last 24 hours or so. Those last-minute edits and adjustments, they do differ slightly from what you may have downloaded online.

So, the version presented here may be slightly different. There is a paper version of all of the revised presentations out in the foyer, and the revised electronic versions will also be posted online shortly after the workshop.

So, I just wanted to make sure that I mentioned that.

So, why are we here today? Well, the first reason is because the natural gas team, the Natural Gas Unit, really within the Energy Commission, has an obligation under the Integrated Energy Policy Report mandate to look at market conditions out into the future and to help use that information to inform the broader policy discussions that are a part of the IEPR.

So, this workshop is being held as a part of the 2013 Integrated Energy Policy Report.

And so we utilize a number of tools to get us where we want to be, to help us gain insight, but not all of those tools are capable of the kinds of insight that you can gain from talking with experts in the field, from people who actually have their hands down into the weeds dealing with these issues.

And so another part of what we're -- why we're here is to gain stakeholder input.

Stakeholder input includes -- we've broken this out, really, in two halves. The first half is to talk, in the first half of the day, about changes in how demand will change the infrastructure necessary to support natural gas inside California and outside California in a way that affects California ratepayers and stakeholders.

So, this is not a rehash of the demand forecast activity that looks at retail sales for natural gas and those types of things, we integrate that information.

But, really, the question here is how will these demand pattern changes affect California's infrastructure in terms of natural gas?

In the second half of the day we're going to be talking about changes in the supply trend, whether that's from shale, where we have some slides and some discussion on, but there are other supply trends that we want to bring out, as well.

Things like liquefied natural gas and the potential for increased export capability in the United States.

And so we're going to include all of that as a part of our discussion today, both quantitative and qualitative.

One of the pieces of the quantitative activity is where do you get all the assumptions necessary to populate the models to really kind of look at the numerical outputs and inputs?

It's easy, sometimes, to look at the outputs and think, well, that's what the model says. But the model says something that's a function of the inputs and we have attempted, in this IEPR, to connect the inputs that are specific to different areas of the energy sector because they are all interrelated to the experts here at the Commission who have responsibility for looking at those areas.

And this is something that we've talked about on numerous occasions. And so, I don't want to spend too much time on this slide.

But, really, the idea is that we’re using the expertise here in the Commission, but outside of the natural gas team to help inform and broaden our understanding of how those issues will affect the natural gas world.

And so, you’ll see that we use a couple of outside sources in terms of the Rice University production costs, and the updated economic and demographic assumptions.

The updated economic and demographic assumptions, by the way, are really kind of the purview of the Demand Office and the demand forecasting team here at the Commission.

The North American Gas Model, which is the purview of this team and will be a subject of the number of the presentations we have today. Those outputs input into a number of other models, both the California demand, the electricity demand model and the California transportation model, which is the purview of the Transportation Division here at the Commission.

All of that feeds into the Western Electricity Coordinating Council, or WECC Electricity Production Cost Model, to help us understand what the electric generation profile looks like and what the gas burn is for those areas.

And all of that feeds back around into the North American Gas Model.

We're not attempting to run these models to complete convergence, and I don't want anyone to get the idea that we will have a grand crystal ball, or an all-seeing eye, or however you want to say it, that will tell us what the future holds.

What we are trying to do is do this in an informed and at least somewhat tractable way so that the inputs that we use for each sector are at least consistent with what broad industry and expert analysis tells us they probably should be.

And so through this process we've done a number of -- we've done two iterations and we expect to do probably another full iteration before we finalize the results.

So, really what we're here to talk about today isn't just the results, but the narratives and the issues that those results help us to understand.

And so, there are a number of possible issues. It would be impossible for us to look at every possible question.

So, to begin with, we've narrowed the list here to questions related to how does hydraulic fracturing affect California stakeholders, and that means both in State and out of State, changes in regulations, those types of issues.

How does the rate of innovation and technology change, how does that play into the future of the natural gas market and then, by extension, the future of the rest of the energy markets?

How does increased reliance on renewables and increased interrelationship and interactions between the gas and electricity system, how does that play a role in the future of California natural gas markets and Western United States?

And then how do California policies affect the California gas market? And we say policy in the broadest sense here. California has a number of very leading-edge policies with regard to energy.

And it’s important for us to understand how these policies may interact.

Again, I would emphasize that the energy sector is an independent -- I’m sorry, interdependent set of sectors, each having an effect on the other, sometimes in interesting and surprising ways.

And so as we go through and look at what these policies do, sometimes a policy that is focused exclusively on electricity may have an effect on natural gas, and that's something that we want to understand, look at, and at least talk about.

Our agenda, broadly, is to talk, first of all in the morning, about the results of the six cases for the California and the WECC that come from PLEXOS. PLEXOS is a production cost, electricity dispatch model.

It's an interesting kind of sub-piece, you saw it on the graphic earlier, where we have to really kind of have to understand electricity dispatch functions differently than the gas world.

And so, we brought Angela Tanghetti, from the Electricity Team, to speak to those issues.

We're going to talk about highlights of the three common cases. And, really, the reference, high-demand and low-demand cases and, really, how have we changed those since the last time we talked about them?

We're not going to speak at length about those individual results. Those results are actually posted and available for download from the website.

But we are going to talk about how we've opened up, expanded, and changed those cases broadly, and how we've addressed some stakeholder feedback since our last workshop.

And then we're going to talk about the highlights from the three alternative cases, which is the California policy case, the natural gas/electric integration case and the low-innovation case, and what those things are -- what the results of those cases are showing us.

But then, as I mentioned, we’re here also to talk about the broader narratives. And to do so we have a panel here, who is already seated. And we’ll have another panel this afternoon.

But our first panel consists of stakeholders and experts to talk about a broad range of issues.

That panel, I will be moderating and I’ll ask the Commissioner to come down and join us when we get to that point.

And, really, we’ll start with some questions, but I would encourage the public, those online and those here in the room, to be thinking about what questions might be good follow-on questions, what else should we be thinking about.

And as we go through that, if you wish to come to the seat here in the center of the room, where there’s a microphone, you can do so during that panel discussion and we’ll definitely field those questions by the panel.

We’ll also open up the lines to both WebEx and phone participants to ask questions.

I will -- just as a matter of housekeeping, I will try to keep the panel discussion generally on track around natural gas issues, or issues that are of relevance to this particular workshop.

So, if you ask a question that is interesting, but perhaps not relevant, we may table that question and try to address that separately, either in another workshop or addressed back to you, as a stakeholder, separately.

So, we'll try and keep the discussion kind of on track.

We may do a -- we plan to have a little bit of a late lunch. So, at about 12:20 we're planning on breaking. And after that we'll talk about the results of the shale cases.

We've actually done 16 variations on how the shale development, how shale resources may play out. And we will have a member of the Natural Gas Team come up and talk about that.

And then we'll move into a second panel discussion, consisting of a number of other folks who are here today to join us, as well, and we'll follow the same ground rules in that case.

And at the very end we will open everything to public comment, so broadly speaking.

Now, if we have room in the morning, if things move quickly, we may open public comment a little bit more before lunch. But I think by about 12:30 people are starting to nod off and get hunger, so we may still cut that short, push those questions off to the afternoon, if we have to, and give everyone an opportunity to have some lunch.

So, that is -- with that, that’s the end of my presentation. That’s what can be expected at today’s workshop.

Our next speaker is Angela Tanghetti, from the Electricity Team, to talk about the WECC and California electric generation and gas burn issues.

MS. TANGHETTI: Okay, good morning. Now, I know at these natural gas workshops the outlook has kind of focused on the national natural gas system, but today I’m going to take it down a few regions and focus this presentation mainly on natural gas use for electric generation, specifically in California.

And then I’m also going to present some of our simulation results from our models on a WECC-wide basis.

But, really, the focus is going to be beginning in California.

So, again, the scope of my presentation will be a look at future annual demand for natural gas by electric generation in California and throughout the WECC.

So, to develop this future look we developed the PLEXOS production cost simulation model. And the annual forecast from PLEXOS are then used by the natural gas group as input to their NAMGas model. Ivin showed you that looped graph earlier.

And in previous IEPRs and electricity reports, if you've been around that long for electricity reports, staff used production cost models.

We've used Elfin, we've used ProSim, we've used Market Analytics to develop input for what used to be called a NARG model.

And for the past two IEPR cycles, the 2009 and 2011, we attempted other analytic approaches to develop natural gas price, supply and demand forecast.

But in the end we found staff could better include more detailed forecasts for California and our specific policy goals if staff internally developed the electric generation forecasts and then passed these results as input to the natural gas model which we're now using, called NAMGas.

So, again, for this IEPR we've developed our analytic skills internally, again, so that we once again can use the product cost model results from PLEXOS to populate the natural gas model, which is NAMGas.

And, you know, I really want to give our team credit because in the Electricity Analysis Office, Chris McLean, Richard Jensen and myself has done something unique in that we've built an annual PLEXOS production cost model dataset.

A lot of them you'll see is only for a specific year, 2022 or 2024, you only look at a specific year.

But we've built a WECC dataset spanning the years of 2014 to 2024. And so the results from these annual PLEXOS simulations are currently included in the mid, high and low energy demand cases. We're also calling those the common cases since their key assumptions are common to the other modeling efforts that are in support of this 2013 IEPR.

And those other models that Ivin also mentioned are the transportation, the demand, our electricity model, and the natural gas model.

So, again, all of these models have one set of common scenarios in support of this 2013 IEPR.

One note that I want to stress here is this is not a study of the amount of natural gas that may or may not be needed in support of future potential operating flexibility need. That's being studied in-depth right now by the ISO, in the context of the resource adequacy, and also by the ISO in support of the PUC’s LTPP.

Most of the slides I’m going to present today are going to use the term “net demand.” And I’m defining net demand based on the preliminary CED 2013 demand forecast that was just presented last May, less any incremental uncommitted EE and new, on-site CHP that’s not included in this demand forecast.

One of the immense benefits of a production cost model is that you can study the impact of both supply and demand side resources on electric gen.

So, for example, we’re able to include the new on-site CHP and incremental EE, which are demand side resources, as supply side resources.

The incremental EE is included using some hourly profiles based on the type of EE program. You know, for example we have lighting programs, refrigeration, HVAC, and we have hourly profiles that were developed back in support of the IEPR 2007 Scenarios Project in order to better understand the impacts of EE in production cost models.

So right now, in contrast, most simulation studies simply subtract this incremental EE from the peak and energy forecast. And that implies that the EE has the same shape as the peak and energy forecast. And so we’ve taken it another step to actually smooth the load a little bit differently than in other studies.

And also, we’ve incorporated both the on-site and the wholesale combined heat and power resources that are part of the Governor’s energy policy goals, into the staff PLEXOS simulation studies.

The renewable portfolios that we’re using in these simulations were slightly modified because we’re using the CED 2013 preliminary demand forecast. And this preliminary demand forecast, 2013, for the forecast of retail sales is lower than the final CED 2011 forecast that were used as a basis to develop these joint portfolios.

Also, in all these cases staff assumed retirement of the OTC plants, as well as retirement of both units at San Onofre. So, all the results we’re presenting today assume the San Onofre is retired.

One interesting scenario we present today also assumes that three coal plants in the WECC are converting to natural gas, and one to biomass, so we’ll look at the simulation results on a WECC wide basis using that assumption.

And I know we’re going over the cases again, but what I wanted to do was refer to these common cases as we’re referring to them.

I know they’ve been discussed in other CEC workshops on demand and transportation, as well as in earlier natural gas workshops, but I just want to remind us here of the key drivers in these common scenarios that impact production cost model simulation results.

One thing I want to note, too, is that the levels of incremental uncommitted ED and new CHP for the high and low demand cases.

The forecasted levels of electricity prices in the high and low demand case are really dictating the levels of these complementary programs in these cases.

So, the low demand case, since it has the highest electricity prices, includes the highest levels of incremental EE and new CHP while the high demand case, with the lowest electricity prices, or lowest energy prices includes the least amount of demand side resources.

The thought being if electricity prices were higher that’s going to incentivize you to include more incremental EE or new on-site CHP.

Again, I’m presenting results for these three additional cases. However, due to time constraints, these cases have not yet been incorporated into the NAMGas model, but I just wanted to give everybody a preview of these cases.

These are preliminary results, but we plan to incorporate these into the final NAMGas simulations, and also into our final report.

Peter Puglia's presentation, following mine, he does present results for these cases from the power gen stand point, but they're not yet the PLEXOS results. We plan to do that for our final report.

The natural gas electric case and the low innovation case required RPS portfolio adjustments based on the exclusion of incremental EE which, again, raises your retail sales forecast, which means you need a higher level of renewables to meet your goal, and also for the assumption that one of the cases assumes a 40 percent RPS requirement by 2025.

So, again, both of those two cases required higher levels of renewables.

From a power generation perspective, the California policy case that we're going to show here in the low demand case is basically identical. So, for time constraints I'm not going to show those results for California, for the California policy case because they're identical to the low demand, but I will show them on a WECC wide basis because that's where you see a slight change.

Okay, so let's get right into the cases here. And what we're calling the mid case, also called the reference case, we're trying to get more in line here. But when I say mid case, this is the same as what we're referring to as a reference case.

The incremental EE and new on-site CHP, later in the forecast period, the red line on top, they show little growth after the year 2020. And, basically, there's no growth in our incremental uncommitted energy efficiency assumptions in any case after the year 2022.

So, you're going to see this, it's creating a slightly positive load growth in our net demand later in the forecast period, mainly because of those two assumptions driving that increase in net demand.

And another interesting assumption is prior to 2017, in all cases Energy Commission staff assumes a very aggressive renewable build in California and throughout the WECC.

And one of the main drivers is our assumption about the expiration of the investment tax credit at the end of 2016.

So, again, when we look at the contracts database, either the PUC's contract database, the Energy Commission's POU contract database, we've looked at utility as filings to the Energy Commission. We've looked at utility IRPs, trade press, and a lot of the renewable generation is expected on line early in the forecast period.

So, for comparisons on this mid case, we were trying to look at other entities that are forecasting any kind of power gen, or natural gas demand for power gen. And we did look to the 2012 California Gas Report to compare our mid case results to theirs.

And at this point that appears to be about the only report that we can find that are looking at year-by-year natural gas demand for electric generation in California, specifically.

This report also forecasts a decline, however, a much more modest decline of only a quarter percent. The negative quarter percent is the annual average through the year 2030.

So, if you look at our graph for natural gas demand, you see a slight upturn towards the end of the period. So, if we were to extend our forecast through 2030, we would have a slightly higher growth.

So, if we looked at the annual average growth, we'd have a slightly lower one than the 2.5 percent we're showing here if we looked through 2030.

But again, the California Gas Report did use the CED 2011 demand forecast, which was higher, so you'd expect to see a higher gas demand for power gen.

They also did not include -- they did include incremental energy efficiency, but only for the investor-owned utilities. So, we have a bit more incremental energy efficiency which, again, lowers our demand forecast on top of using the preliminary 2013, which is even lower than the 2011.

And also in the California Gas Report they assumed no new on-site combined heat and power. So, again, that does drive our demand for natural gas down. It does shift it to another sector.

So, again, even though the Energy Commission staff is forecasting a decline in the demand for natural gas in the power gen sector, we are also forecasting an increase in the industrial demand for natural gas due to this increase in new, on-site CHP.

And these levels for the new CHP were updated in support of our 2012 IEPR and they’re in line with the Governor’s energy policy goals for new combined heat and power.

So, that’s some highlights there.

The low demand case, for this case we’re assuming the lowest levels of net demand, which creates the largest decline in natural gas demand for power generation.

And again, I know I mentioned the California policy case. I’m not showing it specifically for

California, but it’s the exact same trend and amounts for demand for natural gas, so I’m just not showing those. But again, the California policy case in this low demand case are identical in our simulation results.

But I will provide them on a WECC-wide basis later in the presentation here.

So, for our high demand case, okay, now, I know this is kind of interesting. Sometimes you only show bar charts and you miss these kind of interesting details.

And there’s this kind of interesting dip from 2019 to 2020 time period. Again, I mentioned our aggressive renewable build early in the forecast period because of the investment tax credit expiration. So, we assumed that the renewable build is basically static in 2017 through 2019 while some renewable credits are being exhausted, because the RPS allows for compliance over a three-year period.

However, in the high demand case, in order to meet 33 percent we have, you know, a significant bump because we’re using higher levels of demand, which means our RPS is higher in 2020 than in the other cases.

So, we need a more aggressive renewable build in the 2019 to 2020 time period.

And again, this creates this kind of interesting dip in the demand for natural gas for power generation just because we have a big uptick in renewables in those years.

So, the forecast trend after 2020 then follows the other cases, with a slight increase in demand for natural gas for electric generation in the later part of the forecast period.

This 1.3 percent average annual decline is the least amount from all of our common scenarios.

So, I am going to present some results. Again, all these cases we're showing are preliminary and results from the production cost model.

However, due to time constraints, these additional cases that I'm showing right here, these three cases, they've not yet been incorporated into the NAMGas model. And the three common cases, again, are included in NAMGas, the results that we're presenting today.

Staff plans to include these three additional cases' results in the final NAMGas simulations and in our final report.

This natural gas electric case assumes mid-levels of demand, but we assume no incremental EE.

Also in this case we assume a 40 percent RPS by 2025. And so, therefore, the renewable build is a bit more aggressive in the early part of the forecast period, with the same trend as slowing slightly to allow compliance over a three-year period of excess credits in any given year, and then continuing the renewable build out once those credits are exhausted.

Hence, the kind of lumpy nature of the demand for natural gas for power generation forecasts we're showing here.

When we look at WECC-wide results, you're going to see something interesting in this case. Even though we do have a 40 percent RPS goal in California, there is a slight uptick at the end of the forecast period, a slightly greater uptick on a WECC-wide basis.

Because in this case we're assuming that there's some additional coal plants that are converting to natural gas in this scenario. So it does -- you'll see the impact of that later in the forecast period, when I present those WECC-wide slides.

Let's see, our low-innovation case, the demand level assumptions in this case are identical to the natural gas electric case in that we assume no incremental EE.

But the RPS assumptions are different. The RPS build out in this scenario is smoother when compared to the natural gas electric case, which assumes -- the natural gas electric case assumes 40 percent RPS, whereas in this low-innovation case we're still assuming the 33 percent RPS by 2020. And the RPS continues at 33 percent, with no increase after the year 2020 through the end of the forecast period, which is 2024.

So, let's see. Oh, I thought it would be interesting just to put all our California cases on a similar graph. And again, you know, this is preliminary results from our PLEXUS for all -- from PLEXUS simulations for all cases.

And again, the three common cases have already been used as input into the NAMGas model.

The California policy case, again I show here, but as you can see there's negligible results when compared to the low demand case. They basically lay on top of each other.

And again, you can observe the interesting dips in natural gas demand in the high case, as well as the natural gas electric case due to the more aggressive renewable build because of the higher demand forecast in one scenario, and the higher RPS forecast in the other case that we're looking at.

So, those are kind of the interesting results that we've shown for California.

And now, we can move on to our WECC-wide results. When we look at WECC-wide results for all cases, we see that the trend for the six cases show an increase in demand for natural gas for power generation. Again, we show an increase on a WECC-wide basis. California we show a decrease.

In natural case -- in the natural gas electric case you can see that slightly greater uptick in the forecast where it kind of jumps up above the low-innovation line in the 2023 to 2024 time period. And that’s because we’re assuming the two additional coal plants, on top of the common coal plant conversion to natural gas.

So again, for that case we’re assuming that Intermountain 1 and 2 retire in 2023, convert to gas.

Boardman in 2021, it’s going to convert to biomass.

Navajo 1 through 3 in 2023.

And then San Juan 3 and 4 in the year 2020.

So, the total retirements in the later part of the forecast period in that case, for coal is about 5,500 megawatts, with about 4,500 megawatts being -- excuse me, 4,100 megawatts of replacement of natural gas, of which about 200 of it is biomass in Boardman, that we’re assuming.

So, it’s not a 1-for-1 replacement, but it’s still a significant amount of new natural gas generation at those locations.

So, let's see, the next steps here is what we plan to do is there's going to be a -- right now we're using the preliminary demand forecast with some pretty dated incremental, uncommitted EE assumptions.

So, what we plan to do is once the final demand forecast and incremental EE assumptions are available, we're going to update our PLEXOS production cost model with those values and rerun those simulations.

We're going to consider, based on any discussions today, about various CHP penetration scenarios, other than the ones we've already incorporated into the model.

We're going to closely follow the Cal ISO Operating Flexibility Studies, and studies that evaluate the potential need for the replacement of San Onofre.

Right now we've retired San Onofre. And in some cases we did have to add additional amounts of generic capacity in order to not have any energy not served in our PLEXOS simulations.

But what we'd rather just do is allow for the Cal ISO to complete those studies and to better understand what kind of replacement, either capacity, or wires, or some other form of capacity replacement for

San Onofre, as well as any potential operating flexibility needs. We'd incorporate those into the final version of the model.

And what we want to do, what we've done on a kind of a preliminary basis is we've coordinated with the Cal ISO and other entities that are running these electric simulations to just kind of benchmark our results.

To see, you know, given our assumptions are you coming up with similar trends?

Unfortunately, most entities are only running a current year, so we are able to look at the electric generation totals for California and compare those, and so far they've come in line. It's just that we're showing a continuous stream of numbers which show a downward trend.

So, we will continue to coordinate with them, even though we're only going to be comparing those results on a single-year basis.

So with that, I'd open it up to any questions or --

MR. RHYNE: Thank you, Angela. I'll ask if there are any clarifying questions at this point, before we move on. No?

I'm sorry, go ahead.

MS. ROTHROCK: I'm not sure if it's clarifying or not, but what kinds of CHP penetration scenarios might you look at?

MS. TANGHETTI: The CHP penetration scenarios were developed based on an ICF report that's available. It was part of the IEPR 2012 update, so those are on our website.

And they're consistent with the Governor's goal of 6,500 megawatts of new CHP throughout the forecast period.

So there are various levels of it based on kind of policy incentives, as well as electricity prices and other variations in the market.

So, we do have three scenarios of it. One is, again, more aggressive and that's what's included with our low demand scenario.

MR. TUTT: Good morning, Tim Tutt from SMUD.

I have three questions, I think. The first is looking at slide 10, the natural gas electric case; it has no incremental energy efficiency and a higher RPS than is required. I'm just wondering about the rationale for that case. Why that set of assumptions?

MS. TANGHETTI: You know, I didn't -- this was part of the natural gas, I can't speak to that, so I'd like --

MR. RHYNE: Yeah, thanks. So, one of the principles behind generating the scenarios was to look at stressing the interrelationship between gas and electricity. And in doing so, we believe that a higher electricity demand, along with a higher renewable portfolio standard, taken together created sufficient stress that we thought that we would be able to at least see something of interest in the results.

And so the rationale was to create a stress case rather than a directive policy case in that regard. So, that was the idea.

MR. TUTT: Okay. When you run your models, and it looks like it's driven in part by California electric demand, but do your models allow for California power plants to sell power to the reset of the WECC and continue operating even as demand changes here, or renewable development changes here?

MS. TANGHETTI: Oh, definitely. The dispatch model does actually show exports, but not aggressive exports that we've seen.

When we look at the import levels in these cases, they're definitely lower than they have been historically. And part of it is we are assumed to import renewable energy to meet the RPS.

So, mainly what's driving the import/export scenario is the demand in California. Our demand is significantly lower than when we forecasted through other IEPRs.

So, the model is allowed to export gas, but I can’t say exactly how much we’re exporting. We’ll have to look at that in more detail.

MR. TUTT: Okay, thanks. And then the final question, and it’s on slide 12, you have all the scenarios compared. And in 2014 they seem to start out with a reasonable gap or, you know, differences about demand, and that’s only next year.

So, the question is what’s driving that gap next year in the models?

MS. TANGHETTI: Well, what we’ve done is we’ve taken the three demand forecasts, which start at different levels of demand in 2014.

So, by 2014 we’re forecasting that the mid, high and low range are different.

And what’s also causing that variation, although there’s no incremental uncommitted EE, we’re not adding that until 2015.

What’s driving those right there is our assumption about new, on-site CHP. So, we’ve included new, on-site CHP in 2014 in our demand forecast which, again, lowers the amount of load because we’re assuming that load that used to be on the demand side is now generating its own energy for use. So, that's what's driving the variations in 2014 is this new CHP.

MR. RHYNE: All right, any clarifying questions on WebEx or the phone?

Okay, with that then we will move to our next presentation. Robert Kennedy will talk about the changes in the common cases and how we've addressed stakeholder input.

MR. KENNEDY: Thank you, Ivin.

I'm Robert Kennedy. I work in the Natural Gas Unit here at the Energy Commission. Good morning Commissioner and guests.

In the past I've presented on the common cases and I tended to focus on input assumptions and results. But this time around I'm going to shift gears a little bit and take a slightly different approach, and focus more on how we've responded to stakeholder comments and suggestions.

And I'll still touch upon assumptions and results, but that won't be the focus of my presentation.

Okay, so you just saw a presentation from Angela describing how we receive demand for natural gas in the power generation for WECC. And what we did was we put that into our NAMGas model for the WECC region, turned off the elasticity and hard-wired those numbers in.

For the rest of the non-WECC states the elasticities remained in place and still in effect.

Now, I looked at -- I compared the initial demand, what we had in the model to start with versus what we received from the production cost model. And the formative years weren't that different.

And looking out into the forecast years the demand inputs for the forecast years there was some changes, but it wasn't on the order of magnitude that we saw significant changes in quantities or prices.

The reason why I bring this up is comments submitted since April 24th; those comments are still applicable to our discussions today.

And some of the comments I'll be addressing is the forecast price range, saying it should incorporate more uncertainty. And also talking about the trade position, the import and export numbers that we presented in our previous workshop.

But before I go there, I just wanted to kind of flash this up on the screen. This is the results from our common cases. A snapshot for the year 2025, our reference case and our high demand/low price case, and our low demand/high price case.

Now, I don't want to spend too much time here.

As Ivin mentioned, this is on our website, available for download.

You see percent differences here versus the reference case, the green above the reference case and the red below.

I'm just going to use this as a point of reference and I'll be referring back to this later in my presentation.

So, the first comment I wanted to talk about was a long-term natural gas price forecast should incorporate more uncertainty.

This was a comment received since the April 24th workshop, from PG&E. And they felt that the range that we had in our three comment cases, the prices that we saw, the ranges were too narrow and didn't incorporate enough uncertainty.

And I just want to point out to everyone there's been a big change since 2008 with the great production coming from shale and that affected our production cost curve, which is the single most important input into our NAMGas model.

And, basically, there's several things in the market that can put uncertainty and there's some things that can add certainty.

And if you look at recent historical numbers, the last recent years you can see that the natural gas prices have been lower and less volatile. So, I think it's important that everyone remembers that.

So, there were some suggestions on how to deal with this. We thought about maybe adjusting some of the input assumptions and we felt like we already went as far as we could as far as one thing we did was we adjusting the cost environment. And we didn't want to continue to adjust assumptions and have input that just wasn't probable or made sense.

So, it was suggested, well, why don't you look at past forecasting errors and maybe you can do something with that. And that's the approach we went with.

But I just want to point out in doing that we're keeping our three common cases.

Okay, so our first step was to go back and look at our past forecasts and compare them to historical Henry Hub numbers. And you can see this big jump up. This is the, of course, historical Henry Hub. These are our past forecasts and you can see they're kind of clumped up here, kind of like a $3.00 differential between all the forecasts.

And I really like this graphic because I think this illustrates why we do our modeling in the first place.

You can see this big spike right here and remember back when the prices got to around $13 per MMBtu. I could make a debate that was our forecast wrong or was the market wrong?

You know, that’s up for debate. There’s a lot of futurist activities that drove up all commodity prices.

But the reason why I point this out is just to illustrate the fact that there can be unforeseen occurrences that happen, and that’s why we try to model as best we can to account for these things.

So, we took all our forecasts and we looked at the -- for each year, for each year in the past our highest difference above actual numbers and our lowest below the actual numbers, and we did that for all the years.

And then we took a percent difference and we ran a regressive trend line to get an equation for that trend line and we applied that equation to our reference case.

Now, when we did that, that affected this upper bound you see here, and also the lower bound. You can see that’s a nice big range right there.

But this is what it looks like when we put our three common cases with the upper and lower bound, and you can see a lot more uncertainty is captured in this balanced action versus our three common cases.

So, I think it's important to know that we're in the flat section of our supply curve, all the production of the natural gas basins.

And it's important to keep in mind that we are using an annual average model. So, that means fluctuations within daily operation business, it didn't capture it in the model. So, this does a better job of accounting for those uncertainties that could go outside this range.

About a month ago the Northwest Power and Conservation Council held a meeting, they have a subsection called the Natural Gas Advisory Committee, where they get stakeholders together and they look at forecasts that are out there to help them plan for natural gas use for power generation.

And they presented a slide similar to this. And this shows other groups' forecasts versus our own. The CEC forecast is represented in the red and other groups, such as S&L, Idaho Power, Evista and EIA are represented here.

And you can see with these other forecasts the CEC range does a good job of capturing about 80 percent of this range.

There’s about -- there’s one forecast that goes outside, on the high side, and there’s two on the low side.

But I want to illustrate that all of these forecasts are captured within this error band.

Okay, now I want to talk about the next comment, which is the CEC trade position. In the previous workshop, April 24th, I presented a graphic that showed a map of the lower 48 showing imports and exports coming in and going out, and it affected the net import of 4.6.

Now, it’s about 4.5, after we went through a model iteration.

So, PG&E pointed there’s a lot of groups out there that -- and that was for the year 2020, by the way. And PG&E pointed out that a lot of industry groups out there, the EIA for example, and ICF, project the United States will be a net exporter by the year 2020.

So, we were encouraged to reexamine our trade position.

So, part of the reason that the stakeholder submitted this comment because it was felt that going forward United States will export more natural gas to Mexico and also to Asia, and Europe in the form of LNG.

So, I want to first talk about LNG. Looking at the annual energy outlook from EIA, you see about 1 TCF going out for the year 2025 and that's roughly about 3 BCF a day.

If you look at our reference case -- and these are net exports, by the way.

And if you look at our reference case, we have about .765 TCF being exported, and that's about 2 BCF a day.

In our high price/low demand case we have about 2.67 TCF going out for the year 2025, and that's about 7.3 BCF per day.

And keep in mind, looking forward we received industry comments just saying that looking forward to the year 2020 they expect about 3 to 6 BCF a day being exported in the form of LNG.

And right now there's about 9 BCF on the docket for approval to export LNG. So, we feel like that number's reasonable. It falls within this range.

Next, I want to go back to the results and talk about Mexico export. And currently there's about 7 BCF per day of capacity on the docket to build capacity to export to Mexico.

Currently, there's about 3.8 BCF capacity and we're seeing about 1.5 BCF per day going to Mexico.

If you look at the number of our cases here, we have about three going for the reference case and for the low demand/high demand case we have 3.7, and our high demand/low price case we have 2.9 export to Mexico.

And we received comments that stakeholders expect about 3 to 5 BCF per day to be exported for the year 2020. So, we feel like this is a good range right here.

So, for LNG and exports to Mexico, we feel like we’re comparable with other forecasts out there.

So, we asked ourselves, well, what’s affecting this net important? And we found out that it’s imports coming from Canada.

And currently, the United States received about 8 BCF per day coming from Canada.

And I just want to remind everyone we saw, prior to 2008, where we saw a lot of production coming from shale, there were increasing amounts coming from Canada. Since that time prices here in the lower 48 have plummeted and we’ve seen a trend of increasing imports coming from Canada.

Now, if you refer back to the prices that I’ve shown for our three common cases going forward, in all three cases prices do increase going forward.

And if you move forward, in the year 2025, we feel that by that time while shale capacity has been slower to come on line, we feel that more shale capacity will be available and Canadian gas will be competitive with the U.S. prices and we'll see more imports coming from Canada.

And while demand in Canada is projected to increase a little bit, still there's a lot of spare supply available for the lower 48.

So, I just kind of wanted to remind everyone about our inputs for the reference case. There is no additional capacity build out. We're standing pat on what was recently approved for LNG export, about a little more than 3 BCF per day for our Sabine Pass in Freeport.

And for our high price/low demand case, we do assume a capacity build out for LNG export up until the year 2017, which is about a little more than 8 BCF per day.

But again, for all of our cases we do show price increases and we do see significant imports coming from Canada, which helps explain the net imports that stakeholders have seen.

And I know a lot of people had contacted me, asking to see some of the results ahead of time. I know we were kind of late posting the results, but they're available now.

And we encourage all of you to look at those results and submit your comments, if you would like to comment, and look at some of our input assumptions, we welcome that.

And, you know, just this morning my supervisor showed me an article saying that Canada plans to aggressively go with LNG exports.

And I want to remind everyone this is a long-term forecast. We're looking ahead to 2025 to see where prices and supply will balance out in the future.

So, we are still going through the iterative process where we plan to input demand numbers from our demand office, commercial, industrial, residential, and also transportation demand sector for natural gas. And that will provide an opportunity to, you know, adjust the model as we so choose at that point.

Any questions, I'll be happy to answer.

COMMISSIONER MC ALLISTER: Robert, I've got a quick question, actually. So, the chart you showed about all the different projections out there and then the sort of top end and the lower end, where just a couple of them fell outside of the range, do you remember offhand which -- what the sources were for the ones that fall outside the range? I'm just curious, really.

MR. KENNEDY: Oh, the sources.

COMMISSIONER MC ALLISTER: Like the very high one, obviously, is kind of notable.

MR. KENNEDY: The AEO low oil cast, this one right here.

COMMISSIONER MC ALLISTER: Right, okay.

And then the lower end, which fell outside the range?

MR. KENNEDY: Yeah, the Northwest Power Conservation Council.

MR. RHYNE: Yeah, it’s one of the scenarios created by the Northwest Power Conservation Council. It’s actually they label it as Scenario L, and so that’s Council L is the label there.

And the other one is a forecast provided by Evista. So, those are the two that fall outside on the low band.

COMMISSIONER MC ALLISTER: Okay, I just -- you know, obviously, you kind of want to know who’s producing which forecasts to kind of give it the appropriate level of, you know, get a reasonableness read on it to see if it can then -- you know, if it needs to feed back into your analysis, but just curious, really. Thanks.

MR. RHYNE: Thank you, Robert.

All right, our next presentation is by Peter Puglia, who will talk about -- excuse me -- who will talk about the three additional scenarios, beyond the common cases, that look at issues of California policy, electricity and gas interaction, and low innovation.

MR. PUGLIA: Good morning. My name is Peter Puglia and I'm with the gas team. And I'm going to try to move through this as quickly as possible because it's after 11:00.

Some of this you might recognize. It's a brief review of my April 24th IEPR workshop presentation. During that presentation I offered a more detailed look at the assumptions for these three particular cases, each of which has a controlling narrative, which I hope you're able to pick up as I try to put it together for you.

But since the April 24th presentation we've been able to run those cases using our Market Builder Computable General Equilibrium software.

And when I show you the results, probably the most important thing I'd like you to keep in mind is that I'll be comparing each of these three special cases with the reference case.

The reference case results have been modeled using the PLEXOS WECC power generation gas demand numbers. Okay, so we used those as inputs.

Angela mentioned this, there is an interaction between our gas modeling and the PLEXOS power gen modeling.

Okay, we do an iteration running the PLEXOS model to feed into the NAMGas model, and then that closes up the gap hopefully enough that we don’t have to do multiple iterations between the two, because we want the PLEXOS and the NAMGas results for power gen gas demand to come to an agreement. That’s an optimal a solution as you get without having a model that talks to both sides; gas demand and then power gen gas demand.

So, please keep that mind. What I’ll be trying to do, with that in mind I’m going to try to paint three clear pictures for you of each of these cases.

Okay, what a possible response in the future of the natural gas markets would be to these sets of assumptions.

So, just again to cover, in brief, the first of the three cases, the California policy case. The point of it was to simulate the response of natural gas markets to the implementation of California policies, capturing assumptions about energy efficiency, renewable resources, distributed generation and combined heat and power, CHP.

So the way we worked these out to populate the model is we start out, Angela mentioned this, the California policy case begins with the low demand/high price case, okay, one of the three core cases.

What it does, though, is also we changed a few things. You can see them right here. The California RPS, the 33 percent by 2020 is satisfied. Other WECC states are delayed three years. And you can see the rest right there.

Angela noted this on slide 8 of her Power Point.

Okay, right to the results. Generally, the most important results people want to look at are the prices, and so I've posted those first.

And for probably the three most important price points, the three major utilities' Citygates, and you'll see that the reference case follows a lower price trend than the California policy case for each of the Citygates.

But again, those are prices. The model and the reference case use the PLEXOS numbers, which aren't changing too much because power gen is not the whole of the State's natural gas demand. There's residential, commercial, industrial, transportation, utilities, other things.

Okay, where it is really important is in the results in the upper left-hand corner, California power generation demand.

Okay, if you look at Angela’s results, you’ll see that in 2015 she has about .900 TCF. And you’ll see that ours is a little bit lower.

When we rerun the California policy case, as with the other two cases I’m going to discuss, those are going to converge. We’ll populate with the PLEXOS numbers and we’ll post those for you to see, and you’ll see a convergence in order to get the two models to come to an agreement.

And the same for the 2020, PLEXOS doesn’t model 2025, so there isn’t a correction there, but it will still be -- we use a growth rate to extend the PLEXOS results and model that appropriately.

Okay, the conclusions are pretty clear from the policy cases that you end up getting a pretty significant impact on California power generation gas demand. And you also get, because we assume, you saw it two slides ago, we also get a much higher transportation sector demand to satisfy optimistic natural gas vehicle penetrations.

But in the grand scheme of things California demand, the bottom left-hand chart, doesn’t change very much with the California policy cases versus the reference case.

And when we repopulate, run again, it’s still not going to change very much. Okay, because if you look at just the scale of things power gen demand is about a fifth of the total State gas demand. And transportation demand is 2 percent. It doesn’t amount to a whole lot.

Which means it doesn’t amount to a whole lot in terms of prices, either, because those are also evaluated on a western basis.

Okay, one of the other assumptions was the addition of the Monterey shale. We didn’t do this in the last IEPR. We’re doing it in this one because you can’t really ignore the Monterey shale at this point. If you do, people think you’re not paying attention.

So, we added it to this case because it’s the best fit. It’s part of the narrative of how things would be going if we add these policies and, with the increasing attention on the Monterey shale, that resource is developed.

And you can see for California production the results of adding the Monterey shale are quite significant, but for U.S. production it’s not a whole lot of a difference over the reference case.

And of course, again, the difference is just scale. It maxes out at about a trillion cubic feet a year, which means it's, what, ten times what reference case production would be in 2025, but U.S. production overwhelms California production. California's a small player in natural gas production, so it doesn't make that much of a difference.

A few important things I want to mention about the Monterey shale, okay. Our assessment of the Monterey shale gas is speculative and generous. And the biggest reason is there aren't any reliable estimates for oil or gas for this shale play, okay.

The third thing is that the general history of oil and gas field assessments is that they're usually revised upward significantly. Not very many are revised downward. So, it's -- this is a speculative look and we chose a generous assumption so you could -- it's more interesting to see results like that, basically.

Who wants to see nothing? George will talk later about this, I know he will.

The second case, the natural gas/electric synchronization case, basically the purpose, as mentioned back in April, it's the same.

It's gas markets' response to renewables, high renewables penetration, the highest of the three cases, but without incremental electricity, efficiency demand reductions, and also energy efficiency demand reductions.

And it begins with the reference case assumptions and the tweaks we make to it is that we populate a 40 percent RPS by 2025, the 33 percent RPS is met by 2020, as is the current statutory goal, and all of the WECC states meet theirs on time.

There's no incremental energy inefficiency, which I mentioned. And also what we assume is 80 gigawatts of U.S. coal-fired capacity is converted to gas-fired capacity.

That's from an update of a Brattle study that dates from October of last year, and they parceled it out by the control grids, 6 gigawatts of that is in the WECC.

The WECC is, as far as coal generation is concerned, is probably the cleanest of any of the interconnects.

So, this doesn't -- this assumption, alone, doesn't have the really big hit on this case that the other assumptions do.

And, of course, prices are always the first for people to see and there's not a big effect, right. Meeting California and WECC RPS targets doesn't affect prices very much.

Okay, and again, the notes I gave you about California power generation demand, comparing the gas electric synchronization case with the reference case, the reference case has been repopulated with the PLEXOS power gen demand numbers. And so you see those results, the gas electric synchronization case, as with the California policy case, and the last one I'm going to show you, the low innovation case have not yet been iterated with the PLEXOS power gen gas amount numbers, so you're going to see that change.

Angela gave you a little over a trillion cubic feet for the year 2015 for the gas electric synchronization case, and she gave you about .85 trillion cubic feet. And there's still a pretty good gap that needs to be closed up in our modeling exercise and we'll be getting to that.

Okay, the last one, the low innovation case. This one, the purpose of it was to look at a change in the way things have gone in gas markets' thinking. With the glut of shale gas washing over North America everyone has gotten accustomed to low prices. The prices that Henry Hub dipped below $2.00 in April of last year, this is a modern low.

And what we're trying to do is look at, well, what plausible assumptions might reverse that thinking and get market participants to consider some other kind of world that plausibly could happen?

So, this is what we're trying to simulate here would be lower gas reserves, lower exploration and technology proliferation and, also quite reasonable, would be higher water disposal costs, water usage, and disposal costs, and drilling as a result, largely, of hydrofracturing regulations.

This case begins with the reference case. We don't add any incremental energy efficiency. We cut the natural gas resource base by 12 and a half percent, and we added regulatory costs of 50 cents and 30 cents to shale and to conventional gas resources, respectively, to cover for these operations and maintenance costs due to water usage and water or other fluid disposal costs.

Okay, finally, we also changed the technology improvement rate to 0.5 percent per year, which is half of the reference case rate, and that's the best technology that's available to use in exploration and production, the rate at which that technology is introduced into gas fields, okay, into exploration and production.

We also increased the backstop price from $15 in the reference case to $20. The model, the purpose of the model is, as with any one, it's trying to maximize the present value of a resource to simulate what markets really do.

But it also includes the absence of inter-temporal arbitrage opportunities because it’s necessary in order to achieve that end.

All right, but future exploitation of a resource is always an alternative to current production, so the maximizing solution of that present value also requires that you specify a resource value beyond the model’s time horizon. The model’s time horizon is 2070.

In order to do this, the model assumes that a backstop technology will cut in and limit the sales price of gas. The price of gas just can’t go on, and on and up. Of any commodity, you can’t just go on, and on and up forever, so the model attempts to simulate reality by including this, along with the other assumptions.

That’s a methodological -- some of you guys do that and you’re looking at it going what is that? And that’s what it is.

Okay, again prices for the low innovation case. You notice the prices are higher. This is intuitive. If you cut the gas reserve across the United States by 12 and a half percent, you’ve cut the introduction of the best technology for producing that gas to half of the reference case rate.

And in addition to that you've added costs for fluid usage and disposal per 1,000 cubic foot to this particular resource. You're going to get higher prices. But it's modest, okay.

So, you're paying 42 cents to 53 cents according to this model. It's not what the future is. It's what you might see. You'll see something like that.

Okay, because we made assumptions that changed gas production this case is showing you charts that deal specifically with production and in some detail, both U.S. production, California, and U.S. Shale.

And again, this is pretty intuitive. You're getting -- from the low innovation case you're getting lower production everywhere but in California. And I can't explain why California doesn't change at all.

But it's -- it doesn't assume the Monterey shale is developed, so for that -- partly, that might explain it is California production currently isn't relying very much on those assumptions.

Okay, then of course demand. Price, supply, demand, that's sort of the three-way picture of any kind of analysis.

Finally, U.S. demand using these -- again, these are national assumptions so you're going to see -- in contrast to other assumptions, you're going to see change in total U.S. demand. It's not very significant.

Also, similar changes in California demand. With the low innovation case you see lower demand.

Power generation you see a big change in demand. But it's converging. As you get into the outer years you go beyond the data that I'm showing you here. Out towards the forecast horizon you'll see that the two close up.

That concludes my presentation. Anybody have any questions?

MR. RHYNE: Hey George.

MR. WAYNE: I'm George Wayne with Kinder Morgan. Peter, I have a few questions for you regarding the cases. You know, I came in a little late.

When you talk about all the different cases which one are you referring to as the most likely, or do you have a definite -- do you subscribe a most likely anything?

MR. PUGLIA: No, none of them.

MR. WAYNE: Okay, the reference case is the --

MR. PUGLIA: The reference case is business as usual. It's existing policy and it's -- it's none of the cases are currently viewed as being the expected case. We'll call it that if Commissioners want one.

MR. WAYNE: Okay.

MR. PUGLIA: We'll populate that appropriate.

MR. WAYNE: Yeah, and we've talked about that before, but I just wanted to --

MR. PUGLIA: Right. No, it's a good thing that you brought that up.

MR. WAYNE: Okay. Going to the California case, the policy case --

MR. PUGLIA: Right.

MR. WAYNE: -- and when you're referring to the Monterey, which we'll talk about later --

MR. PUGLIA: Yeah.

MR. WAYNE: -- if you could bring up that slide because the one thing I want to note, when you were talking about the production, that TCF a year, yes, it is very generous and speculative, like you said.

But one thing I want to ask with regards to the resource, what's the amount of resource you assumed would be developed? In other words, the total amount of resource you assumed to be developed?

MR. PUGLIA: When I glanced at the results and just added them up in my head, I was looking at about probably 20 trillion cubic feet total. Because just adding up it levels off at about one in year 2022, and then it stays at that for about another decade, and then tails off.

MR. WAYNE: Okay, because I was -- I quickly, you know, summed your -- you know, you should be able to sum the area under the curve, that is the blue curve.

MR. PUGLIA: Right, right.

MR. WAYNE: Okay and you have half of it, so you assumed the other half follows a bell-shaped curve, if you will.

MR. PUGLIA: Right.

MR. WAYNE: You're going to over -- based on that trajectory, you're going to over-develop the resource. You're going to develop more resource than the 20 TCF that you're talking about.

MR. PUGLIA: Right.

MR. WAYNE: So, that's sort of one reality check that I had in my mind.

The other one is the 2015 is very aggressive. Because what that would require is something close to -- in the next six months you'd have to have almost 200 horizontal rigs working in the Monterey to be able to meet that half-a-TCF-per-year of production.

And again, between now and the beginning of 2015, or the middle of 2015 I don't see that happening.

MR. PUGLIA: Would you mind submitting that in your formal comment. I like that.

MR. WAYNE: So, anyway, those are my comments.

MR. PUGLIA: Thank you.

MR. TUTT: Good morning, Tim Tutt from SMUD, again. With regard to the California policy case, one assumption was the most aggressive natural gas vehicle goals are met, or most optimistic I should say, sorry.

MR. PUGLIA: Yeah.

MR. TUTT: What about the most optimistic electric vehicle goals, are those also included in the California policy case?

MR. PUGLIA: No, sir. There’s your answer, Tim, no they’re not.

MR. TUTT: Is there a reason why not? It’s California policy.

MR. PUGLIA: Could have done it.

MS. TANGHETTI: Well, embedded in the electric gen model are assumptions for electric vehicle penetration. So, not necessarily in the NAMGas model, but we do incorporate those in our common cases. And since this case starts with the low demand or high price case, there is an assumption about varying levels of electric vehicles.

I don’t know it off the top of my head, but we do vary the level of electric vehicles in our demand forecast. So, indirectly it is, we do consider that as input in the model through PLEXOS.

COMMISSIONER MC ALLISTER: But just to be clear there’s not sort of a direct, you know, relationship between adoption of natural gas vehicles and adoption of electric vehicles built in here anywhere. And I think it’s reasonable that that shouldn’t be the case, necessarily, right. I mean I think we’re covered on both sides here in the right places.

MS. TANGHETTI: Okay, that’s in the transportation sector model, so I don’t want to speak to that. But I just want to say that we do address electric vehicle penetration levels in our forecast so --

MR. PUGLIA: And Commissioner, to complete the answer to your question, the transportation office is going to provide us with their own gas demand modeling results that we’re going to use as inputs into our NAMGas model and run through the case. So, you’ll see that reflection.

The electric vehicle assumptions that are run in PLEXOS produce outputs of gas demand that wind up becoming inputs. They have for the reference case, and there will be inputs for the other cases, too. So in that sense you’re seeing them reflected, also, in the gas modeling.

MR. RHYNE: All right, it looks like we have a question from a WebEx participant. All right, Lynn Davis, go ahead.

Lynn Davison?

All right, we’ve muted him again.

All right, I think we’re going to move on. Are there any other questions in the room?

MR. ELLSWORTH: I have a quick question. Does anybody know whether the Monterey shale is oil or NGL rich? Would it make a difference in the speed that it’s developed? It seems like a lot of producers are going for those types of shale gases.

MR. PUGLIA: Yeah, would you please repeat your question, sir?

MR. RHYNE: Into the microphone, please?

MR. ELLSWORTH: Oh, excuse me. Does anybody in the room know where the Monterey shale is oil or NGL rich because that seems to create incentive.

MR. PUGLIA: It’s an oil play. Yeah, currently, it’s being treated as an oil play.

MR. RHYNE: Okay. All right, with that we’ve reached the point in the agenda when we -- excuse me, when we’re going to move over into the panel discussion. And for that we’ll take just a quick minute to reset.

I’m going to invite Commissioner McAllister, if you'd like you can join me down at the table here.

Just some quick ground rules for the discussion. I do have -- I do have some starter questions that I will pose to the panelists.

I'll also invite, George, if you're interested, to come join us on the panel. We've actually got a seat set aside for you on this panel, as well as the second one.

And so I'm going to pose some questions to the panelists. If they have something they'd like to add, they think they can speak to the question, then I'll ask them to do so. Otherwise, a pass is fine.

After we get through these initial starter questions or if you, as a member of the public, think you have a question for the panel, I'll invite you to come up and ask the question.

I'm going to try and keep things on track. So, if we start to veer too far off of the particular topic, I will bring us back around and close off discussion just so that we can keep things rolling.

We are targeting a 12:30 wrap up for lunch. That gives us about 40, 45 minutes once we get things started here.

And I'll actually ask the panelists if we need a very short break before we get started. Are we good or do we need a short break?

Okay, I think we’re good. It’s probably better not to lose too much of the audience before we dive into the panel discussion.

So, with that I’m going to take -- I’m going to kind of change places here and we’ll go ahead and get started.

All right, so what I’m going to do to start with is I’ll ask our panelists just to -- obviously, we have names in front of us here, but just for the sake of those on the room and those online, we’ll just quickly go around the table, if you can just introduce yourself and let us know what organization you’re with.

And then once we do the introductions, I’ll kick off with the first question.

So, if we can start over here with Erica.

MS. BOWMAN: Yes, I’m Erica Bowman with America’s Natural Gas Alliance.

MR. SUBAKTI: Dede Subakti with California ISO.

MR. FAN: Chris Fan with PG&E.

MR. WAYNE: George Wayne with Kinder Morgan.

MR. ELLSWORTH: Chris Ellsworth with Federal Energy Regulatory Commission.

MS. ROTHROCK: Dorothy Rothrock, California Manufacturers and Technology Association.

MR. RHYNE: Okay, wonderful. Thank you.

Okay, so my first question for the panelists and, again, this panel really is focused on questions relating to how changes in demand profiles may change the California -- the need for California infrastructure or infrastructure across the Western United States.

So, the first question is how will changes in industrial demand patterns create new stresses on the existing natural gas infrastructure?

Any takers on that one?

MS. ROTHROCK: This is Dorothy Rothrock and I'm with the California Manufacturers, so the word "industry" is in the question, so I guess I should say something.

You've already talked a lot about CHP as probably the most significant natural gas-related demand component of industry. And the choices that manufacturers are going to be making over the next decades in order to, frankly, survive in California is going to depend on their adopting as much CHP as they can because it is such a valuable technology in terms of energy efficiency.

And as carbon prices keep going up and as other costs don't go down, then we're going to need that to stay competitive.

So, that's probably the biggest kind of technology-related thing.

But I wanted to say something else about what's happening globally that might impact California if we do the right things at the State level.

And that is that there's a view that there's going to be kind of a manufacturing renaissance happening in the U.S. as developing countries, wages are increasing, transportation costs are -- or logistical issues are making manufacturers look again at growing in the U.S., rather than overseas.

There will be, we believe, a tendency for manufacturers to start coming back to the U.S. Whether they come back to California or not, or as opposed to just sort of fly over and head to the Midwest, and southeast or something is dependent on whether or not we have a favorable business climate here.

So, I was looking at some of the gas reports in preparation for this and I noticed most were saying, well, we're transitioning in California. We're moving from a manufacturing to a service-based economy, so that means our demand profile is going to be flat or declining.

But I think that could actually reverse and we could see a shift in the up direction. And combining that with CHP demand could kind of double up and you might see a surprising increase in natural gas demand from the industrial sector.

MR. RHYNE: Thank you.

MS. BOWMAN: I'll actually add on a little bit on a global perspective with respect to the industrial development across the U.S.

There definitely has been a lot of interest in capacity additions and new infrastructure in terms of manufacturing, a lot associated with the petrochemical sector because feedstocks are used -- or dry natural gas as a feedstock, and that's a high component of the manufacturing process cost.

I think when you look on a map at those proposed facilities through like 2020 a lot of those are locating in Texas and Louisiana.

And I think to kind of flip to the question that's been asked, they're locating there because the infrastructure's there.

And then there is some supply growth that's been happening in the Midwest where they're looking. Obviously, because of the Marcellus shale development, they're looking as well to locate in the Midwest areas.

There are a few projects announced in California, but I think that's something to think about in just terms of if you want to invite industry into California, how friendly they are -- the State is to businesses, that would be very helpful.

MR. RHYNE: Thank you. Maybe I'll maybe reframe the question just a little bit for the utility and maybe George.

If we see a manufacturing renaissance that moves into California significantly, combined with significant combined heat and power, from your points of view what does that mean for California's natural gas infrastructure?

Are we going to have to rethink or are we going to have to kind of rebalance how we utilize that infrastructure? Will we need new infrastructure?

What are your thoughts on that?

MR. FAN: This is Chris Fan with PG&E.

Looking for the last couple years, the infrastructure actually has been growing in California, the gas infrastructure. So, the pipeline has been growing, the pipeline infrastructure into California has been growing.

And then also the new gas storage facilities, there's been new gas storage and expansion of gas storage facilities.

Speaking on PG&E, in Northern California, there is a pretty substantial growth of facilities, including storage.

So, looking in Northern California I think infrastructure-wise it looks okay.

But then Southern California, in general, we're going to talk later on about kind of the supply, and about SONGS and those issues.

But if we're looking at Southern California, they do have a pretty large load pocket in the southern part of Southern California, so the San Diego area.

So, if you're looking at infrastructure that might be something that might need to be addressed.

But then speaking most of kind of PG&E in Northern California, I think we're okay right now.

In general, higher demand leads to higher utilization of the pipeline, so I think that's going to be where we're going.

MR. RHYNE: Okay.

MR. WAYNE: Yeah, the only I'll add, and really it's probably more of a question than anything else, with the growing renewable portfolio standards, you know, the target of 33 percent, we know that growing demand, particularly industrial demand where it's more 7-by-24 type take will require adequacy. And, you know, intermittency is not something that's part of the equation that it can work with.

So, with growing RPS standards, that is sources that are intermittent, we need storage, gas-fired generation to be able to backstop that.

And I have sort of general question, again, if we think we're on target of that or that question's been answered?

MR. RHYNE: Well, I think the group, the person on the panel who might be able to speak to that a little bit is the ISO.

DEDE, to you have any thoughts or comments on that?

MR. SUBAKTI: Yeah, sure, this about the California ISO. So, one of the things that's always interesting with regards to the interaction between gas and electricity, Angela talked a little bit about all of the studies that we've done, that we've seen here today is really a natural consumption of what I would normally call a base consumption or base utilizations.

The California ISO right now is still looking at the study and analysis of the flexibility to -- the need for the flexible capacities, both in the generations with regards to transmissions, energy, as well as the gas to back it up.

The flexibility is needed to make sure that we have the ability to follow the need, the demand, and that's basically for the variability of the potential renewable that comes in there.

Many of you might have noticed that our analysis and our studies indicate there could be the potential of what we call the two peaks, load net demand where you have a high peak in the morning, and then the solar comes in and, you know, your net demand certainly settles down in the middle of the day, and then it comes back up again as evening comes up.

So, that is one of the things that's of our concern and then we're focusing to make sure that we have flexibility for that.

But there's portions that we're actually looking at and we'll talk a little bit more later when we talk, maybe people are interested about SONGS.

It's that as we're looking for a replacement energy that comes in for SONGS you have to ask the question do we want to build another generation inside of California or do you want to build a transmission line that allows you to import more.

The thing with the transmission line is that's always nice and it's good when you have the transmission line there. Now, you're just asking yourself what do you do if you have a contingency in the sense that you have a fire on the transmission line, a transmission line has to be tripped off?

And that brings me to the third portion of what I call the contingency demand. When a transmission line trips or a generation trips, you need to be able to readjust your energy system.

And what we do normally use, we do use a peaking generator, a fast-start unit. And these fast-start units, they're all gas usage rate, and they're all sucking up, basically, from a gas pipeline.

And if you think about a transmission line that carries 1,000 megawatts and you just lose it right away and you have to replace that 1,000 megawatts with a natural gas unit the question is, again, do we have infrastructures to be able to suck up and utilize that storage right away for us to mitigate the need for the energy site.

So, I think all in all, from our perspective I think we're going in the right direction. We're looking at the base needs. California is actually still looking at the flexibility needs and we're also looking at what do we need for contingencies in the case of fire, or catastrophic stuff that's in there.

MR. RHYNE: Thank you.

COMMISSIONER MC ALLISTER: I want to just provide a little bit of context here as well. So, a lot of these themes on intermittency, obviously, they overlap with electricity and we had a really good interagency -- or multiple-agency panel within the IEPR, and also together with the CPUC on Monday, in L.A., to talk about the SONGS outage and renewables integration in the context of Southern California and electricity system infrastructure needs.

It was very, very interesting. I just want to highlight how important a topic this is with respect to the -- where we're going to -- particularly in Southern California where we're going for the long term with respect to maintaining adequacy and reliability of the electric system.

And the really, tremendously open question, the open question of how that -- how much, really, the impacts on the natural gas-based generation fleet of that transition away from SONGS and into the incorporation of more renewables. That is a tremendously open question.

You know, energy storage on the electric side could actually offset, potentially, the rush of demand at a contingency.

You know, you've got SWIPL and Sunrise kind of right alongside each other. If both of those went out it’s a big deal, right.

And so we obviously have to have that contingency planning done and it’s an open question as to what that looks like.

So I think, you know, certainly, when I looked at the preliminary slides the other day and saw that the demand -- even in the high case demand basically was still, you know, declining to flat.

I dug into that a little bit and I think am satisfied with that, you know, really, even if we’re talking about an expanded gas fleet, open question, but if that’s the sort of future we still are talking about plants that aren’t operating that many hours and, therefore, are not using a lot of gas.

But this intermittency issue that really comes to the fore is the fundamental question on the gas side. So, this is very, very, extremely topical.

Let’s see, you know, I’ll leave it there for now because I think you’re going to touch on some of these issues further along in your questions.

But, really, it’s good we have some good heads in this discussion here because it’s super important to dig into this issue.

MR. RHYNE: Thank you.

So, let me kind of go to the next question, but use this particular set of topics as a segue.

Mexico is seeing an increase in industrial demand. They have a growing industrial base and industrial economy.

We also see an extensive expansion or planned expansion, I should say, of the natural gas-fired electric generation in Mexico and that's something that we've talked extensively at the Natural Gas Working Group here about.

I'm curious what the panelists think with regard to that additional expected gas demand, as well as the proposed gas expansion pipelines that are going from the southern part of the -- the southwestern part of the United States down into Mexico, how will that -- how will that affect, first of all, the gas system in the southwestern portion of the United States?

I won't limit this just to California because the system, itself, is interrelated.

But if you have any thoughts either on the southwestern portion of the system or how it might affect California specifically, I would be curious to hear.

MR. ELLSWORTH: Actually, I'll just go back to your previous question on industrial and then kind of feed into the Mexico issue.

On the industrial side is -- what we've found is that on the long-haul pipelines that go from the Gulf Coast up to the northeast is that they've become somewhat under-utilized compared to where they were before when the Marcellus shale was developed.

There's been a lot of push-back from that gas in the northeast as they kind of take away some of the Gulf Coast traditional gas markets.

So, the development of industrial load, particularly in the Gulf Coast region is actually probably a good thing for those pipelines because they should see greater use.

Going to Mexico -- so, studies that we've seen are showing maybe 10 to 20 percent growth in industrial load in the U.S., which is maybe about 1 to 2 BCF a day of growth over the next decade.

If you couple that with projections of what we're seeing for Mexico, you may be looking at an additional, you know, 2 BCF a day growth. So, you're looking at, you know, 4 or 5 BCF a day growth.

If you couple that with LNG exports, which I know we're going to get to, then that's a tremendous amount of growth coming, taking a call on traditional kind of Texas supplies that will undoubtedly pull gas away from the traditional southwest markets in Arizona, California, and so forth.

And going towards pipelines, we talked a little bit about manufacturing in California. Pipeline routes into California are already pretty full. I think Mexico is going to make them flow at even greater capacity utilization.

And so we've entered into a relatively tight market, one of the more expensive markets in the southwest and it seems like growing trends are not going to alleviate that particularly.

MR. RHYNE: Thank you. Any other thoughts?

MR. WAYNE: I mean I'd like to answer some of that. Obviously, Kinder Morgan has a significant amount of exports going into Mexico off our pipeline system.

One I can speak to in particular is EPNG. With regard to this question I'll talk about impact we believe will happen to deliver pricing in California because of the Mexico growth. And more importantly, questions people have been asking as far as transportation capacity; is there a scarcity that would be developed or that would happen as Mexico grows and obviously calls on additional transport capacity down into the laterals to feed the various parts of Mexico.

I think it's important, though, to look at the -- I mean if I take a step back, the current situation as far as California is concerned.

You know, as speakers have said, there’s an abundant and growing amount of natural gas in North America. You know, we’re growing in the Rockies, the midcontinent, Canada is an abundant resource, Marcellus that’s northeast, Appalachia has abundant resource.

And that’s going to keep natural gas prices at a fairly low level, you know, somewhere between the $4 and $6 range for the foreseeable future and, really, the $6 not probably until ten years out, somewhere beyond 2020.

And that’s what’s stimulating a lot of this additional demand. Mexico sees that. Obviously, industrial sector sees that and they want to take -- they’d like to take advantage of it to be able to stimulate their economies.

As far as California, you know, California is 10 BCF a day or more of interstate pipelines into California. There’s only six -- five and a half to six BCF a day annual average demand.

So, there’s a lot of slack capacity on these pipelines going into California. So, California, as far as interstate capacity, is very well piped.

And we know that all of the forecasts show that in the various sectors, where you look at power gen, industrial, residential, commercial California’s forecast to be declining consumers of natural gas going forward.

We talked about in-state storage, that's growing to meet peak day demand. And we talked about, you know, very aggressive renewable portfolio standards, demand side management. All that spells to is I believe -- we believe California is very well positioned in the future, despite a growing Mexico, to be able to satisfy -- really, to be able to satisfy its needs.

Just talking specifically about Mexico, you know, our current -- if you're an EPNG shipper, and that's the pipeline that's going from the Permian Basin into Southern California, and we have a north main line and a south main line, right now we have over 500 MMCF a day of open transportation capacity on the south main line.

On the north main line we have over 800 MMCF a day of open capacity on the north main line.

It's welcome for anybody to step up, we'd be willing to entertain long-term contracts for that capacity.

The point is there's enough, there's an abundant amount of open space on EPNG.

Yes, Mexico will absorb some of that space. People are talking about 3 to 4 BCF per day of incremental demand. We think that’s probably more around 3 BCF a day.

Probably the most important piece of that, though, is when you talk about West Texas, New Mexico, Arizona, Southern California, the demand in the north central, northwest part of Mexico over this time frame is only an incremental 500 a day of demand.

The lion’s share of that demand is happening in South Texas, Reynosa, Brownsville, that’s where most of that demand in Mexico, when you talk about that 3 BCF a day, two and a half of that is really -- that’s where -- that’s where the natural gas is going, from the Eagle Ford, from the onshore gulf to the offshore gulf going into central Mexico, and lower southeast Mexico, and there’s really no connectivity between north central, northwest Mexico, and the lower portion of Mexico.

So, that’s really what California, if you will, is competing with is what’s happening in, really, the north -- the desert southwest demand in Mexico, not so much what’s happening in South Texas and south central.

But again, more than enough capacity on EPNG, Transwestern, Transwestern who I’m representing here, they have the capacity, really, to be able to take that supply from the San Juan Basin, Permian, which is growing, and to be able to deliver it to Southern

California.

COMMISSIONER MC ALLISTER: Do we know the content of that demand? And maybe this is also a question for Dorothy. Is this industrial demand, new industrial demand, is it residential, what's the --

MR. WAYNE: In Mexico?

COMMISSIONER MC ALLISTER: Yeah. Well, yeah, across the border in sort of -- or, I guess, you know --

MR. WAYNE: Yes, it's --

COMMISSIONER MC ALLISTER: -- or is our desire to bring new industry to California competing with folks that are choosing between us and them, right, just sort of getting at --

MS. ROTHROCK: Yes, always.

COMMISSIONER MC ALLISTER: Yeah, there you go. That's kind of what I suspected.

(Laughter)

MR. WAYNE: That industrial demand -- you know, I guess maybe you don't consider power gen growth industrial demand.

MS. ROTHROCK: No.

MR. WAYNE: Yeah, most of the growth that we're seeing, they're doubling their gigawatts of power and over the next 20 years.

MS. ROTHROCK: Yeah.

MR. WAYNE: That’s where most of that demand is coming from is power generation, converting -- adding new CCCT additions or converting from fuel oil to --

COMMISSIONER MC ALLISTER: So this is CF, I mean this is the electric utility in Mexico, it’s -- CFE, sorry.

MR. WAYNE: Yeah.

COMMISSIONER MC ALLISTER: So, they are procuring much of this gas to generate?

MR. WAYNE: Right, yes.

COMMISSIONER MC ALLISTER: Thanks.

MR. SUBAKTI: To add to that a little bit, in California ISO we’ve noticed that with regard to generation utilizations that’s utilizing the Northern Baja line, pipeline, we don’t really have that many generations inside of California that’s using that Northern Baja line.

So that’s with regards to that pipeline, to begin with I think we’re okay.

And like George mentioned, there’s a lot of generations being added into the CFE area to supply for their own demand, either as manufacturing in CFE.

But what we’ve also noticed that they also -- when you look at it, from the electrical side there’s only -- there are only two transmission lines between

California and CFE in Mexico. And Mexico is, literally, only have two transmission lines going anywhere else which means that if the two transmission lines are out of service, you're by yourself and you have to be able to meet all your electrical demand within that Northern Baja California.

Some of you may know, some of you may not know the fact that during summers and some of the time that the CFE is a net importer and they only import from California because those two lines are in California.

There has been talk about -- discussion about increasing the import capability because they do need the megawatt to supply their need for either residential or manufacturer, I'm not quite sure what it is. But most likely it's on the manufacturing side.

But they do have an increased interest in importing more energy from California ISOs. And in which case, then, if they're right on the right price then we would supply that energy from our natural gas units to their energy need. So that's just some points to consider.

COMMISSIONER MC ALLISTER: It seems like the industrial growth just across the border is also potentially significant.

I guess I don't -- I'm not fully up to date on this, but I mean the maquiladoras over there have traditionally -- you know, many of them not even been interconnected to the natural gas grid and have been trying to get interconnected.

Presumably, that's going to continue, you know, as both our economies improve, so it would be nice to kind of understand that a little more fully.

MR. WAYNE: I mean the study I saw was the U.S. has a significant advantage in the industrial sector of Mexico. I think our electricity prices are like 48 percent lower than what Mexico is.

So, Mexico sees, you know, natural gas as a feedstock to be able to compete with the U.S. on the manufacturing side. Again, because their electricity prices, their retail electricity prices or the price the industrial pays is, again, almost 48 percent higher.

MR. SUBAKTI: Ivin, one more thing that I want to add. I think you asked a second question, a portion about the new future gas pipeline down in the southwest.

I just want to share a little bit of a challenge that we had last -- I want to say it was last year, a couple of years ago, when we had some pipeline works in the Southern Cal system.

When there is that work on the pipeline systems, then all the generation in San Diego, natural gas generation in San Diego will rely and will share with the Northern Baja line.

And it was much simpler to do it when SONGS units are in there. And when the SONGS units are not in there then you're looking at rerouting all that gas needed for San Diego through Northern Baja line.

And, you know, we would support the need to see the potential of being able to have that additional capacity just for us to be able to know that, you know, if there is any other gas pipeline work that would require us to support generation more in San Diego from the Northern Baja line, that actually would be very helpful for us.

MR. RHYNE: All right, Chris.

MR. FAN: So, then I've got some research and some stuff that I've been looking at on the Southern Lake. So, for El Paso line on the Sullen Lake what we've been seeing is that there's proposed about a 1.2 BCF of pipeline expansion that's going to go towards Mexico.

Right now, when we're looking at kind of Mexico and currently I think there's about a 3.5 BCF export capability total going to Mexico. I think it's flown about 2 BCF.

And one of the big limitations of the flow is on the Mexican side of the border where there is -- there's limited amount of pipe to really pull all of the gas away from the border over to the generation.

So, Mexico is in the process of doing that, building those pipelines.

I think one thing we have to consider is that Southern California or California is at the end of a straw, basically. So, capacity itself, when you're looking at capacity there may be available capacity, there may be competition for capacity. But what happens is if we're at the end of a straw and the flow of gas goes towards Mexico and because, you know, the prices are able to flow it down that way, then that's a consideration that Southern California or California as a whole needs to think about is how much gas is going to be flowing from the south over to California.

Another thing is looking at the two paths that are flown into Southern California. The southern path is the one that is used to serve the southern region, kind of San Diego region of California, and that's going to be the one that's also where the expansion projects are going into Mexico.

So, it seems like that that's going to be a limiting amount of gas that's going into the southern region of California.

MR. RHYNE: Thanks. That's actually a great distinction to make between the pipe capacity and the actual pipeline flows and understanding that distinction, I think. Thank you, Chris, that's good.

MR. WAYNE: Just one thing, if I can, add to what Chris is saying. Yes, California, Southern California is at the end of the straw but, again, firm rights, firm contracts guarantee that flow occurring from source to sink.

So, that's obviously a way of eliminating that downside risk.

The other thing is just from a ratepayer's perspective, you know, increased demand from Mexico, particularly on our pipeline is actually a good thing for California or any shipper on the system. You know, more building determinants keeps steady revenues, okay, and we won't see rate creep or rate fly up because we're losing building determinants on the pipeline as we're losing load.

So, again, increased -- this increased demand from Mexico is actually, from an EPNG shipper, a good thing.

MR. RHYNE: So, can we quote you on that, George, that more demand means rates stay flat?

(Laughter)

MR. WAYNE: Well, I just think that phenomenon is just sort of a fact of rate making.

MR. RHYNE: I'm kidding. I'm kidding.

Okay, so I think we're going to shift to the next question here.

So, one of the interesting elements of the natural gas system and network is that liquefied natural gas acts as the bridge between continental markets and overseas markets.

There was a period of time in recent history when California really thought that there was going to be a need for extensive liquefied natural gas imports.

We live in a slightly different marketplace now, one that's kind of shifted and turned around on its head where we have abundant gas supplies. And that gas is being sold at a significant discount to what it might fetch if it were able to be sold overseas.

So, there's a move to increased liquefied natural gas or LNG export capabilities.

So, I was wondering if the panelists could maybe talk to a couple of questions. First of all, what do you see with regard to how much LNG export capability is realistically going to be built?

We know that there's about 11 and a half TCF a year of just in the inside of the continental United

States that's in the queue that's being asked for, requested.

But how much is realistically going to be built?

And then the second half of the question is that given that some amount of LNG export capability is likely to be built, what effect do we expect to see as we expose -- as we expose our U.S. markets to those overseas markets where gas is actually bought at a premium?

MS. ROTHROCK: This is Dorothy with the California Manufacturers and I don't have any of the answers to the questions that you just asked.

But I just wish that California could be an exporter. If anybody's going to earn extra money from the sale of goods, then why shouldn't California be there doing it?

But at this point I don't see that we do have the capability so all the benefits of that will be going to other states in the country and we'll be poorer for it.

Does anybody disagree with that?

MR. ELLSWORTH: Yeah, I was going to say I think most of the exports will probably happen from the Gulf Coast, where the actual gas supply is.

California's got the disadvantage in that it has to import a lot of the gas supply from the rest of the country, you know, primarily from the Rockies and West Texas, and also Canada.

So, I think an export terminal here is unlikely.

And that goes with there being talk about turning around Costa Azul and making that an export terminal, and I think that seems unlikely.

But I think, you know, within the global marketplace maybe a couple of LNG terminals on the Gulf Coast looks feasible.

There's also talk at the Kitimat terminal up in Canada looking pretty feasible. But that doesn't appear to take away from the net supply available to the lower 48 because the reserves for that terminal are kind of dedicated to that terminal and probably wouldn't be developed otherwise.

You know, the DOE so far as approved about 14 terminals for FTA, that is free trade countries, but it's only two terminals so far for non-FTA countries and it's unclear, you know, when they're going to approve any more at this point.

MR. FAN: I'd like to kind of add a little bit on there. So there are currently like two terminals and that's, I think, about 3 BCF of export capability.

The first one's going to come in around 2016 and so if we’re looking at about 2020, kind of answering your question, of kind of seeing a 3 to 5 or 3 to 6 BCF of potential kind of export capability through LNG.

If we’re looking like, we said, mentioned before, for Canadian exports or Canadian LNG, that’s going to be using a whole new source of gas. That’s shale fields that’s in British Columbia that hasn’t really -- I mean there’s still explorations there, but they haven’t really been tapped to be used.

And gas that flows over to California tends to be in the Alberta area, the conventional production fields.

So, the supply source coming to California would be secure within that way.

Looking at the market and kind of the LNG market as a whole, if we’re kind of predicting gas being around $3.00, $4.00, so you have your export, so you have your liquefaction, which is going to be about $3.00 and then you have transportation which is going to be around $3.00. That’s kind of what I’ve seen. So, that’s going to be about $9.00 or $10.00 for exporting out of the United States.

And when you’re looking at the foreign markets and you have the Asian market which is around $12.00 they’re importing at -- or the Asian market’s at $16.00

and the European market’s around $12.00.

So, they’re still -- I mean those prices are still really high and there’s still that capability.

It really is the government and seeing if they’re going to pass for the non-free trade kind of exports.

MS. BOWMAN: So, in terms of kind of, I guess, the question around to what we expect to be approved, I think it really depends on how the DOE moves forward on their timeline. So, we’ve had two approvals for non-FTA. I guess it’s been three years, now. I mean, granted, we’ve had a more recent one a couple of months ago and they’re expected to come out more quickly now that they’ve finished a lot of their studies.

One of the -- I think kind of stepping back, though, from what’s been proposed, what actually gets approved, I think we really need to think about what will actually get built.

And there’s a lot of, an immense amount of capital that’s required to build these facilities. You’re talking about 5 to 10 billion dollars per project.

So, you’re really limited by your capital markets. You need to find long-term contracts to do the deal. You have a long and very expensive FERC approval process.

So, you know, in terms of facilities actually being able to get everything to come together, line everything up within the window that we're looking at, that the United States actually has a competitive advantage, I think you maybe have four or five facilities at that, you know, 4 to 6 BCF a day, maybe.

And just kind of from a broader global perspective, we have currently 37 BCF a day worldwide in LNG export capacity.

We have a 32 BCF per day demand around there, maybe 35, depending where we are right now in 2013. And that's expected to grow to 50 BCF a day to 2020, 2025.

You have over 40 BCF a day of worldwide proposed capacity for LNG, so that already swamps out the need.

And then on top of that you have 20 additional BCF a day by the U.S.

So, if you stack that up it's really, I think, we only have so much time in which we can get things built in order before, basically, the world takes over in filling that need for LNG.

And as kind of the price components we talked about earlier, not only do right now you have a bit of a price advantage if you were to export U.S. gas to Europe or to Asia, just by the mere fact of the U.S. entering the market is actually pushing those prices down.

Because we're contracting -- the contracts that we see at the non-FTA facilities are very -- they're very different. They're not priced in oil index. They're priced at Henry Hub.

And you've already seen the fact that the U.S. is not importing as much LNG that we thought we were going to push prices down in Europe. It allows for a more competitive environment. So, by global prices coming down, again, you're going to have less incentive for the U.S. to export. And again, it's going to limit the amount of capacity that actually gets built to do so.

COMMISSIONER MC ALLISTER: That's interesting. So, are any of the four, five, six potential facilities that are sort of on your realistic list, are any of those on the West Coast?

MS. BOWMAN: No.

MR. ELLSWORTH: Unless you count the B.C., the one in British Columbia, but that's a little too far north.

MS. BOWMAN: Yes, that's not the U.S.

COMMISSIONER MC ALLISTER: Well, and Costa Azul is not on that list, right?

MS. BOWMAN: No. Now, that may change, I

mean --

COMMISSIONER MC ALLISTER: Yeah, sure.

MS. BOWMAN: -- who knows.

COMMISSIONER MC ALLISTER: You're reading tea leaves.

MS. BOWMAN: Yes, that's right.

COMMISSIONER MC ALLISTER: But they're useful tea leaves.

MR. ELLSWORTH: I was going to add one more thing on the LNG exports, adding to what you said about there being a limited time to do it. Also, I think the U.S. is vulnerable in terms of the sources of gas. It's one of the more high cost sources.

So, it will be at a competitive disadvantage to a lot of the other sources of LNG. You know, if you look at places like Qatar, which are expanding, they can produce gas for 50 cents, or so, or maybe even cheaper a million BTU.

We're looking at some of the large projects that are coming up in Australia. They can produce gas for, you know, sub-dollar a million BTU. So, you're automatically at a disadvantage in terms of the price of gas going into the LNG gate.

COMMISSIONER MC ALLISTER: You're talking about incremental cost over non-LNG or just taking natural gas and turn it liquid?

MR. ELLSWORTH: Yeah, I'm just talking about the cost of the feedstock gas.

COMMISSIONER MC ALLISTER: Oh, okay.

MR. ELLSWORTH: So, in the U.S. you're going to be paying -- you know, currently you'd be paying at $3.60, $4.00 a million BTU for your feedstock gas. You know, in Qatar you're paying 50 cents.

COMMISSIONER MC ALLISTER: Interesting, okay.

MR. ELLSWORTH: And, plus, the U.S. tends to be furthest away from markets than most of the other producers. So, there is a competitive disadvantage for the U.S. to overcome.

MR. WAYNE: The only thing I'll add there, really it depends on where you're looking, there's certainly some of those buyers, Asian buyers looking at like British Columbia. And they're not looking at, necessarily, economics or cost. They're looking at diversification of supply and security of supply, and that's a large resource.

So, that's the big impetus. They're doing upstream deals with large players like Mobile, Apache, Chevron and locking in those supplies, and incentivizing them to produce and then delivering to their market. So, it's just not purely, you know, I guess, marginal cost, economics of production or development. There's other factors that are coming into play when it comes to securing that supply, the way the Asian market's looking at it.

MS. BOWMAN: That's definitely true. And I think the way Qatar's been pricing, they do have a very cheap supply of gas. And they've chosen the oil index because they can. And they've chosen to limit their amount of demand they're pushing out in order to fill demand because they were able to index to oil.

I think with the U.S. coming in and being an alternative source, just as George was mentioning, it allows another player and you can actually create more competition in the global market for those contracts, and it is going to impact global prices.

MR. RHYNE: Now, I'd like to maybe go back to something Dorothy said. One of the ways that in order to kind of understand and spread the results of our model to push prices higher and reduce demand in the United States, we had kind of looked at the possibility of maybe expanding the LNG exposure of the U.S. markets.

And in doing so it actually tends to drive up price, at least in an economic, equilibrium type of analysis it does so.

And that actually can produce winners and losers and it certainly has some folks a little concerned that opening U.S. markets will drive those prices up.

I think the U.S.-wide industrial association actually opposed opening LNG. And so it's an interesting kind of conundrum.

At what point would you and your organization maybe be concerned? At what price point would that create an issue?

MS. ROTHROCK: I don't know. Everything that I saw in the presentations today, to the extent that, I mean, I'm not an expert in this area, it's not my specialty, but I kept trying to find what is it that's really going to shake up this market, that's really going to make a difference?

It seems like it's so flush that it's a very good market in that nothing big is ever going to really derail it very much.

And I guess we've been used to much more difficult natural gas price environments in California in the past, and we survived them. The manufacturers have adapted to them or whatever.

And I guess, you know, I don't want to say that this would be the position of the association, but at this point a very modest, perhaps, price change in natural gas to reflect what you're suggesting might not even be noticeable. You know, given everything else we have to deal with as manufacturers in California, so now I get to complain a little bit, let's talk about electricity prices. You know, that's the next panel I want to be on.

(Laughter)

MR. RHYNE: Okay. Thank you. That's actually a great segue. We've only got a few minutes left and I want to get to this last topic.

And I'm actually going to combine the last two questions into one.

Electricity and the electricity marketplace certainly has an impact on natural gas. I think we've touched on it earlier in this discussion. We brought in Angela, from the electricity team, to talk about her modeling results because of that.

There are kind of two things going on and I'll ask panelists to speak to either, or both, if they'd like.

One is a move nationwide away from coal generation due to a number of factors which, you know, like it or lump it those are the factors that the industry is dealing with.

And so that certainly has an effect on the national natural gas marketplace and kind of by default has effects on California.

The second is more California-centric in that California has targets and goals that really emphasize distributed generation, smaller generation resources, and includes pretty significant amounts of combined heat and power. I think we mentioned that earlier, as well.

How do these two trends in the electricity marketplace, one national and one local, how do we expect that to play out here in California, or in the west, depending on your perspective, and any thoughts you might have on that?

MR. SUBAKTI: Yeah, so this is Dede Subakti with California ISO.

The State of California has always been an importer to begin with, right, and with energy usage and gas usage, I guess.

But specifically with the energy portions of it, right now we’ve actually in the energy portions is that our energy prices in California has been -- the average is always higher than any other energy prices everywhere in the United States.

And because of the energy price being up, a lot of people are able to actually export their excess of energy into California.

We rely on quite a bit of import from our northern states and as well as from eastern portions.

There is not much of a transmission line that goes diagonally, it’s just from the north or from the east.

And currently there is a lot of coal out there in the east and there’s a lot of spot market that is energy importing into California as in the hourly prices, and as well as in the five-minute prices.

All the import right now is priced at the hourly level.

For changes that’s coming up, with their FERC Order 764, it allows us to do a 15 minutes import changes into the California area.

So, however, though, as we are looking at -- you know, I think Angela mentioned about 6 gigawatts of units from coal that’s actually going to be turned over into natural gas, I would expect that the price is going to change and the California ISO or in California may not always be the highest price anymore if the rest of the people are also going to be using natural gas instead of using coal.

Which then level off the questions of whether or not we will be importing as much as we are currently importing.

Couple that with the actual very aggressive renewable portfolio standard, as well as the distributed generations, the net demands in California could actually be lower to a point where people would ask the questions are we actually going to be importing as much as we are right now? And most likely the answer’s no, we’re not going to import as much as we are.

And that would change both the -- I think that would change the energy price quite a bit in California.

And as a matter of fact, the energy price has actually been quite a bit low as we are having more and more renewable, as well as the more distributed generations.

I do want to mention, still, you know, we always go back to this variability. Because we are pricing energy every -- you know, every hour, but every five minutes for all of our locational marginal prices for energy, there could be challenge for us for this variability.

Just because of the hourly price is actually going to be low, it doesn’t mean that the actual five-minute price is actually going to be low, as well.

Because you could have potential price spikes in the five minutes where your price actually spikes for that five minutes or the ten-minute interval that you really need because of contingency, or potential variability that’s in there.

MR. RHYNE: Thank you.

MS. ROTHROCK: I’m sorry, did you have someone else?

MR. RHYNE: Go ahead.

MS. ROTHROCK: One thing I wanted to say about this question, talking about impacts on the system, and the infrastructure needs in the natural gas system associated with CHP, or DG, or whatever is that -- and this relates to the question about whether a little change in cost on the commodity side would make a big difference for manufacturers or not.

And the reality is it’s the transportation costs and the way costs are allocated to large industry, especially the non-core industries for natural gas transportation that really is, probably, the bigger driver in terms of what we care about in terms of natural gas.

Especially now, with commodity prices so low and looking so low off into the future, efforts to move costs to industry by applying volumetric rate design methodologies is a real problem.

And that really does mask, frankly, the commodity cost changes that may be occurring because of all of these things we’re talking about today.

MR. RHYNE: Thank you.

Any other thoughts from the panel?

MS. BOWMAN: Yes, just one thought with respect to kind of the gas and electric interdependency as you move -- California may move to more combined heat and power, and distributed generation, and then you talk about the intermittency issues is just the burden that that move may have on the existing utilities.

I’m certain PG&E experiences this or is concerned about it. And how they maintain their own transmission lines because I don’t think it becomes so much of a gas issue as it might be becoming more of an electric issue in terms of how do you provide that backup support for when those renewable resources are -- I’m sorry -- how can you provide the wires that you need for the backup support for these distributed generation, at least from the renewable side, you know, if you don’t have that through put through the wire side.

COMMISSIONER MC ALLISTER: I want to just point out and maybe ask Dorothy or somebody else on the panel a question about this. But CHP seems like it is one of the -- you know, Angela talked about it, you know, our projections there are really kind of based on the policy, based on the sort of existing policy.

But I think there’s actually quite -- there are a bit of -- you know, a number of questions about what the future CHP actually, you know, the size of that marketplace, new versus sort of continuing, existing facilities, versus retirement of existing facilities and what all the scenarios really are going to end up adding up to going forward.

And it's kind of a separate -- in a lot of ways it's a separate question, really, an independent market for the kinds of services that industries, as they exist in California, are looking for.

I guess I'm wondering if there is, you know, given what you said about prices and how they sort of inhibit industry, is that likely to generate, you know, momentum towards, say, meeting the Governor's CHP goals, you know, by getting new CHP in line as, really, a cost competitive or sort of a cost -- yeah, a cost-competitive alternative to utility supply.

And if so -- well, it would be good to kind of have some context around that.

MS. ROTHROCK: A very short answer to the question is three words, departing load charges. That's probably the single biggest barrier to adoption of CHP for large industry.

I think the whole lot of it would be -- is perfectly economic and makes perfect sense to embrace.

But when faced with the transition cost of moving away from the utility service, and those departing load charges makes it uneconomic.

COMMISSIONER MC ALLISTER: Thanks.

MR. RHYNE: Okay, so we've reached 12:35. I want to thank all of the panelists for participating. This has been a really useful and helpful discussion.

We're going to break for lunch for an hour. We will return at 1:35. We will have a presentation at that time by Leon Brathwaite from the Natural Gas Team, talking about shale.

And then we'll have a second panel discussion focusing more on the supply side issues.

So, I thank you all very much and we are on break for lunch.

(Off the record at 12:35 for the lunch break.)

(Reconvene at 1:40 p.m.)

MR. RHYNE: All right, folks, good afternoon and welcome back. Welcome back from lunch, as well, to those online.

This is a continuation of the Natural Gas Lead Commissioner Workshop -- I should say and the IEPR Lead Commissioner Workshop on Natural Gas Issues.

My name, again, is Ivin Rhyne.

So, this afternoon we're going to have fewer presentations and we are going to have a panel discussion on natural gas supply issues.

And we’re going to kind of follow the same format we did this morning. Hopefully, just in a more abbreviate form.

So, again, we have a set of panelists who we’ll be talking with later this afternoon, a different set with the exception of George, who’s kindly agreed to stay on and play double duty on both the supply and demand panels.

And so with that, we’re going to get started with Leon Brathwaite and his presentation on the shale production uncertainty cases.

MR. BRATHWAITE: Ivin, thank you. Good afternoon, Commissioner. Good afternoon guests, stakeholders, good afternoon.

I will be talking -- I am Leon Brathwaite. I work in the natural gas unit and I’ll be talking about some work that we are doing with the shales.

Now, I just want to be clear about these cases that I’m going to present. We are not talking about likely cases and we are not talking about plausibility. We are just trying to examine impact, potential impact.

So with that, let me get into the cases, get into my presentation.

So, I think it is safe to say that natural gas production from shale formation have soared over the last ten years or so.

In May of 2013 production from shale formations exceeded 31 BCF per day. And this, according to Littman, the Littman database, made up about 40 percent of the production in the lower 48.

Now, all of this is going on because of the accelerated development of technology we have seen in the natural gas industry, especially in hydraulic fracturing and in horizontal drilling.

But, obviously, this is not without some controversy. We have several things that are ongoing right now and they are being discussed in many, many forums.

One is the potential groundwater contamination, that being a big issue. Increased seismic activity and that is a particular concern here in California, with a lot of talk of the potential development of the Monterey shale.

The diversion of fresh water, I mean we know some of these, the hydraulic fracturing jobs, they require quite a lot of fresh water. It’s being diverted, it will have to be diverted from other uses.

And, of course, I didn’t mention emissions.

So, this has forced decision makers to try and reexamine some of the policies that are involved with the extraction of natural gas from shales. Some have chosen to delay or postpone their development.

New York is doing this with the Marcellus right now, at least their portion of the Marcellus.

Some of instituted environmental mitigation fees and others are tightening regulations.

I think here in California we are in the process of trying to do that right now. We are not at the end of the road as yet, but we are certainly beginning that process, maybe halfway through.

I think one of our panelists, maybe Tim, can talk to that issue a little bit later on. Okay, and Tim, thank you for coming, I appreciate that.

So, having said that, we want to examine the effect of technology and the effect of policy on natural gas prices and supply and in order to do this -- in order to do this we designed 16 cases.

Now, this is a relatively small sample. It’s a lot of work to get these cases done, but it’s a relatively small sample, only 16 cases.

So what we did, we started with the reference case and we created two technology worlds. We created a high technology environment and a low technology environment.

Then we added two different production levels in each of those worlds, one constraint and the other unconstraint.

And from that we added four levels of environmental mitigation costs.

The first number you see there in the environmental mitigation costs represent the cost that was added to the shales. The second number represent the cost that was added to the conventional production. And this is on a per MCF basis.

Those four levels were the environmental mitigation of 00. Remember the first is the shale, the second is the conventionals.

Then we added a 30/30 case, then we did 55/30 and then we did 67/30.

So, what we ended up with is that eight cases in each of the -- in each of our environmental worlds, in our technology worlds giving you a total of 16 cases.

So how are we going to look at these cases in trying to assess the impact?

Now, we're really and truly trying to see or examine three impacts.

The first of which is the impact of technology. And we'll do this by looking at what's going on in the high technology world versus the low technology world.

The second thing we'll do is that we'll look at the impact of policy on the development and on production, and we do this by looking at the constrained cases versus the unconstrained cases.

We have eight constrained and eight unconstrained. And this speaks -- and when we are looking at this, we got to keep in mind that we are looking at changes in the size of the resource base and changes in the availability of productive capacity.

The third impact, we'll be looking at the impact of environmental mitigation fees. And that will require us to look at group one cases versus group two cases, versus group three cases, versus the group four cases.

Now, what are those cases when I use those terms? A group one case will be a case where we add in zero to the shales and zero to the conventions.

A group two case we add 30 cents to the shales and 30 cents to the conventionals.

A group three case we added 55 cents to the shales and 30 cents to the conventionals.

In our group four case we added 67 cents to the shales and 30 cents to the conventionals.

So, when you hear the word group one, group two, group three and group four, that is what I'm speaking about.

Now, in our last -- in our previous presentation, I think it was on April 24th, if I’m not mistaken, I presented four cases to you that we’re going to run and converge.

And you may think, well, you know, what did we do here? Did we just jump off the boat and forgot about the cases?

No, we did not. What we did, we incorporated those cases into the 16.

So, I presented the shale abundance case. That case is now the high technology, with environmental mitigation of 30/30 and unconstrained.

The sale we considered is a low technology environment, with environmental mitigation costs of 55/30 constrained.

The shale expensive is a low technology, environmental mitigation 67-30, unconstrained.

And the shale deferred is high technology, environmental mitigation 55/30 and that case is constrained.

So, the four cases that we started off originally, we expanded to 16. You know, I don’t know, we like work around here so we do a lot more work than we need to. No.

(Laughter)

MR. BRATHWAITE: They're just making us earn our paychecks, that's all.

Okay, but in order to set these cases up, in order to -- in order to set these cases up we had to change some key variables.

And those changes occurred, number one, in the supply cost curves.

So what we did there is that we changed the supply cost curve by looking at a 15 percent increase in the resource base all the way down to a 15 percent decrease in our resource base.

We also looked at changes in -- we also looked at changes in the rate of growth of technology called innovation.

Now, if you look at that schematic in the right-hand corner you see a green line. That is the low-tech world, okay.

So, what is happening there, you only have a half a percent per year of technology innovation ongoing and it is only dropping the cost down to about 95 and a half -- 97 and a half percent of what it otherwise would have been.

Because the way technology is manifested in our model is that as technology is implemented it reduces the cost of doing any sort of operation within the modeling world. I think you'll realize that is also true when we're trying to duplicate real life. That's why we say modeling.

Now, the red line on that -- the red line on the schematic shows us what is happening in the reference case. In the reference case we have a 1 percent technological innovation and cost has been reduced down to 87 and a half percent of what it otherwise would have been.

And the blue line is a high tech world, a high technology world. Of course, the technological innovation is occurring at a rate of about 3 percent, and cost is being reduced down to 77 and a half percent.

So, what we are seeing in this particular world is we are seeing the deepest cost reduction and occurring at the fastest rate.

Now, I did talk a little bit about constrained versus unconstrained. Well, the way we implemented that is demonstrated by the schematic at the top of this slide.

The red line represents the unconstrained world. In that case, in that world a hundred percent of resources and productive capacity is available 100 percent of the times.

However, the blue line represents the constrained world. In the constrained world what we did, starting around 2015 we dropped the capacity availability by 5 percent, reaching a limit of about 75 percent, and then leaving it there for a couple of years, and then allowing it to increase and getting back up to its normal level after 2025.

Now, some may ask, well, why did you allow it to come back? If it’s constrained, why don’t you leave it constrained at all times?

Well, we can think about a multiple of profiles that we could have put into the model. This is the one we chose.

Now, is there some practical reasoning behind this? Well, there is.

I mean we think that after a while the industry will adjust. They will be able to better handle whatever policies are in place and then we may be able to see the total productive capacity coming back, but it will take about ten years for this to do so.

But that is what our constraint -- that’s what our constrained world look like.

The other changes we made, the last change we made was in the environmental mitigation costs. And these are added costs, okay.

We have operational maintenance costs in the model right now. What we are doing here now, we are adding costs on top of those costs.

So that changed between zero in cases where we made no changes to the operational and maintenance costs, all the way up to 67 cents per MCF.

Now, I spoke a little bit about a high technology world versus the low technology world.

I just want to give you one picture that shows exactly what I'm talking about.

In the high technology world, in the sustained high technology environment we have a learning rate of 3 percent per year.

Now, when I use the word learning rate, I am saying that is the rate at which technology is being implemented, of 3 percent per year.

The cost reduction is going to go down to 77 and a half percent of what it otherwise would have been.

And there's an under-estimation of shale resources of about 15 percent. That means it's actually larger than what the model originally had.

In the sustained low technology environment we have a learning rate about 4 and 5 percent, and a cost reduction limit of about 97 and a half percent of what it otherwise would have been.

So as you can see, in the low technology world we are not having very much cost reductions.

And the resource base is over-estimated, the shale resource base is over-estimated by about 15 percent. And that means that the actual resource base is smaller than is currently in the original case that we started with.

So now, let us look at the performance of the cases. What happened? What results did we get? Did we find anything that was unusual? Did we find anything that was surprising?

Let us see if we can answer those questions. Well, before I got to the actual schematics that show the results, I want to just lay out a little plan as to how we're going to look at the results.

The first thing that we want to do is look at the effect of technology. And the way we will do that is that I will show you some schematics that are sitting side by side. Okay, one will represent the high tech on your left. On your right you will have the low tech so you can make comparisons of the impact.

The second thing we'll do is we'll look at the environmental mitigation costs, the effect of that. All we got to do there is move from left to right within each schematic and we'll be able to discern a trend.

Well, I hope we’ll be able to see a trend, but we’ll see as we go to the next slide.

And the third thing is the effect of the production constraints. The way we do that is that you’re going to see some blue bars and some red bars standing next to each other. That is how you look at constrained versus unconstrained.

And all the schematics are going to show results relative to the reference case. We are not showing any absolute numbers here. We are just looking at percent changes from the reference case so keep that in mind as we go through the schematics.

So, here we have all four side by side. So, what is happening here, we can see -- we can see in the constrained cases here, which are shown in blue, at first we had a loss of production of 3 percent in our group one cases. Remember, I defined the group one cases originally. Those are the 0/0 cases, where we added nothing to the shales and we added nothing to the conventionals.

We had a loss of about 3 percent originally there.

As we went from left to right, where we’re adding more and more environmental mitigation costs the loss in production -- the loss in production on the constrained case turned out to be about 9 percent.

In the unconstrained case, originally notice what happened. Originally, production actually went up compared to the reference case. Remember, all of these things are comparisons to the reference case. Production originally went up. It went up about 2 and a half percent.

But they time we got, though, to the group four cases, which have the most expensive environmental mitigation costs, production had fallen by about 3 and a half percent. Now, this was in our high tech world.

In the low tech world, though, in the low tech world originally in our group one case in the unconstrained production fell by 2 percent and that grew to about 7 percent by the time we got into our group four cases.

In the constrained, production originally fell by 7 percent and then grew to 13 percent by the time we got to our group four cases.

So, we are seeing, when you're looking at these technology worlds you're seeing greater impact in the low technology environment if you're going to go to the shales.

So, we specifically pulled out the shales because this whole story is about the shales, what's happening to the shales and what potentially could happen.

When we look at the shales directly, in the unconstrained, and we’re in the high tech world right now, in the unconstrained we at first -- we gained 6 percent production relative to the reference case.

But by the time we got to our group four cases we had lost 5 percent in production.

In the constrained world -- in the constrained world we had lost 21 percent originally and by the time we got to our group four cases we had lost 33 percent.

In the low technology environment we started off losing 5 percent and that grew to 17 percent by the time we got to the group four cases. This is for the unconstrained.

In the constrained world -- in the constrained world we originally lost 33 percent and that loss grew to 45 percent by the time we got to our group four cases.

So what we are seeing here, if we can just draw some broad conclusions, the low tech world is clearly producing greater effects upon shale production, and we’ll look at prices here in a little bit.

But as we move from left to right we can also see that higher environmental mitigation cost is also producing greater impacts.

And also the constrained are also producing greater impacts relative to the unconstrained.

So, if now we can go to the price impacts, so these are Henry Hub prices. Again, we are looking at changes relative to the reference case.

Originally, if you remember, I showed you a case where -- a group one case where supplies actually went up, production actually went up. This was in my first two slides.

And on this slide in the high tech world we are seeing prices go down.

So, which is consistent? Supplies are more available? Of course prices are impacted, they go down. So, we are seeing prices fall a little bit by about 2 and a half percent originally, in the high tech world, in the unconstrained high tech world.

But by the time we got to our group four cases prices had risen about 5 percent in our high tech world.

Now, in the constrained cases, though, in the constrained cases the price impact is even larger, reaching about 15 percent by the time we get into our group four cases. Over 15 percent, I should say.

In the low tech world -- in the low tech world, in the unconstrained cases -- in the unconstrained cases prices went up 5 percent originally, but by the time we got to the group four cases prices were up 11 percent in the unconstrained cases.

In the constrained cases, though, the price impact was even greater. Originally, prices rose by about 15 percent. By the time we got to our group four cases, where we’re having the most environmental impact fees, prices had risen about 25 percent.

So what we are seeing here -- what we are seeing here, prices -- the price impact is greater as we move from left to right.

Now, the greater -- the greater impact on prices are occurring because of three things. Number one, low technology world seem to produce more price impacts.

The constrained cases produce greater price impacts.

Increasing environmental mitigation costs produce greater price impacts.

So, can we draw any broad conclusions? Of course we can. We would not have done this study if we could not.

That was a joke, sorry.

Okay, number one, constraining natural gas from shale formations impact prices and supply, in some cases significantly.

Proliferation of technological innovation reduces the impact. Because I told you originally, the way technology is manifested is through the reduction, the reduction in cost, so that is where technology is -- where technology is really impacting the cases.

Also, we are seeing some things that are going on right now in terms of like water handling, and other operations within the industry. We are seeing that they're using technology to try to handle some of the water, by things like recycling, things like drawing when the water flow is high, and storing, and all of these sorts of things. All of those things we are seeing some impacts there.

But the proliferation of technology is certainly reducing the impact.

Environmental policy can alter -- can alter the development. And the production can alter development and production outcomes.

And environmental impact fees can alter the structure of the natural gas supply portfolio.

All of these things I think I demonstrated with my few schematics.

We also have results for other years. Okay, this was just 2020. I didn't want to sit down here and bore you all evening. But we also have 2025 and 2030 results and they essentially show the same thing. The trends are exactly as I presented. The actual changes might be a little bit different.

But there's one issue that's left that this study did not answer, and we have not yet tried to answer.

We are looking at the impact on three items. One, we are looking at technology. Two, we are looking at the environmental mitigation costs. And, three, we are looking at production capacity availability. That's the constrained versus the unconstrained.

The question someone obviously may ask, which one of these things has the largest impact?

Well, we did not try to answer that in this particular study. But the study can be expanded and we can do some sort of statistical analysis and hopefully come up with that, with the answer to that question.

I don't know the answer to that question right now. But if time permits, and with feedback from our Lead Commissioner, we'll certainly try to address that issue.

With that I will end my presentation and turn it over to the Commissioner and to the audience for any questions that you may have.

MR. RHYNE: Okay, thank you very much.

All right, thank you all very much. Thank you, Leon.

So, as I said, we're at the point in the day where we're able to have fewer presentations and move into the panel discussion.

I'll reiterate the panel guidelines since we have a few people in the room who weren't here this morning.

So, the way the panel will work, I'll invite the Commissioner down to join us at the table. And I will moderate the panel.

We'll start with the starter questions that are there in the agenda. I'll probably rephrase them, give them a little more context as we go through.

The panelists should feel free to chime in and add information, if you feel you have something to add on that particular question.

If you have nothing to add on the question, then simply passing is fine as well.

This is a somewhat free-form discussion, so as we go through the discussion, as other topics come up, as follow-on questions arise we can certainly follow down that particular path and deal with the questions as they arise.

However, I will exert a little bit of control here, as the moderator, if I feel that the conversation is getting off the topic or subject of dealing with the natural gas issues at hand.

I will table that question and we will deal with it separately as staff either addressing the question after the workshop, or perhaps in written comment, in that way.

But I want to make sure that we are able to keep this panel and the workshop focused on the questions at hand.

So with that said, I'll invite Commissioner McAllister to join us at the table. I'll take my place and we'll get started.

MR. RHYNE: All right and thank you, all of you for being here.

We'll do one more introduction. I'll as if Bevin will just lead us off and state your name and affiliation, and we'll just go around the table real quick.

MR. HONG: Hi, I'm Bevin Hong with TransCanada.

MR. WHITE: Chuck White, Director of Regulatory Affairs for Waste Management here in the west, and most of my work is in California.

MR. WAYNE: George Wayne with Kinder Morgan.

MR. KUSTIC: Tim Kustic, State Oil and Gas

Supervisor, so I head up the Division of Oil, Gas and Geothermal Resources.

MR. RIVASPLATA: Terry Rivasplata with ICF International.

MR. RHYNE: All right, thank you all for being here this afternoon.

So, the first question really gets to a California-specific element. The Monterey shale we talked about somewhat this morning, in some of the cases, as being a -- as being an important kind of question mark out there for California gas development.

Under what circumstances do you, as a panelist, foresee the development of the Monterey shale in California either for the purposes of gas extraction or for the purposes of oil with a significant gas byproduct?

MR. KUSTIC: I could lead off on that one.

MR. RHYNE: Please.

MR. KUSTIC: Of course, the Monterey formation has been productive for oil and gas in California for over 100 years. But what’s being looked at in particular, now, is the shale formations within the Monterey.

They’re mainly being looked at for oil extraction.

The Monterey is a prolific source rock for oil, but lesser so for gas.

I think one of the biggest limitations of gas in the Monterey is associated gas finding. Industry, I think, would gladly drill for oil and if they find associated gas, they would welcome it.

But just for pursuing gas, itself, it’s difficult right now in California with the divergence of gas prices relative to oil prices.

Historically, they’ve paralleled, but with all the shale gas east of California drilling for just natural gas is very limited.

The Sacramento Basin, which is nonassociated gas, has very little drilling activity. Last year I think there was six wells drilled and a number of those were for gas storage projects, rather than for gas development.

And this is historic. I mean it’s -- I’ve worked in some fashion or the other associated with gas production in the Sacramento Basin for over 30 years and I’ve never seen a case where there was -- you know, a time when there was absolutely no drilling rigs at all in the Sacramento Basin, drilling for natural gas.

And the reason for that is that the price for drilling equipment, the rigs and the service companies is being dictated by the price of oil, which is up, and the price of gas is down.

So, I don’t see industry being too excited about pursuing the Monterey shale just for gas production. But certainly, if there was associated gas with the oil production there’s greater potential.

MR. HONG: I think Tim nailed it on the head because what we see in Canada is where do you want to spend your money? And so right now with oil being over $100, gas in California being around $4, they’re not going to spend their money drilling for gas in California, here, any time soon. I think he nailed it on the head.

MR. RHYNE: Okay. So that gets to a separate question. There’s always the specter of, well, California is a seismically active region and fracking is certainly a technology that takes advantage of certain behaviors in rock, in terms of the ability to crack that open and extract.

Let’s set aside the likelihood or non-likelihood of extracting gas from Monterey. How significant will the water and seismic issues be should someone decide they wanted to develop gas extraction in Monterey?

MR. KUSTIC: I can start with that, again. I guess I’m supposed to identify myself, so Tim Kustic for those people that are -- can’t see me.

So, California has a long history of oil and gas production. And when it comes to seismic activity related to either hydraulic fracturing or other oil field operations, certainly any time you crack a rock there is seismic activity. It’s micro-seismic. If you hit a rock with a hammer in your backyard, or on your driveway, you’re going to break it and cause some seismic activity.

But as far as earthquakes being created by hydraulic fracture stimulation it hasn’t happened and, certainly, not in California.

What’s more likely and has happened in certain parts of the country but, again, not in California, is earthquakes generated by long-term injection wells, where you’re injecting water over the course of many years, if not decades.

California has over 40,000 injection wells. We predominantly product water in our oil fields and a very small percentage of that is oil that’s brought to the surface.

And that water is re-injected for water flood, steam flood and cyclic steaming.

The reason there have been earthquakes associated with deep well injection is the pore pressure in the rock is increased to a point where the rock fractures, not unlike hydraulic fracture stimulation.

But in California the vast majority of injection is done into under-pressured reservoirs, they've already had their primary production, the pore pressure is low, they're injecting water into a reservoir that's under-pressurized, low pore pressure, so you don't have the seismic events related with all these injection wells.

In addition to flood wells there's also disposal wells but, generally, industry tries to put disposal wells where you again have an under-pressure or depleted reservoir because it takes less energy to put water away if the zone pressure is low.

So, as far as seismic events, I think the 100-year production history of California shows that it's really not a significant issue, certainly with the oil field operations, as they are in California.

MR. WAYNE: The one question I had, though, is even though California's had a long history of oil production, gas production and fracking has been used in California in the past, we're talking about multi-stage hydraulic fracturing, which I believe most -- I don't believe that's really ever occurred, at least on a large scale in California.

Most of fracking has been conventional fracking, vertical wells, not multi-stage fracking with horizontal wells. So, there’s a big question mark, really, of what the impact might be if that kind of activity would occur with, you know, 200, 250-type rigs working like we’re seeing in some of these other shale plays.

So, that’s probably my first observation. And then the other one is there are technologies on the horizon with regards to the water use issue, water contamination issue. There’s technologies on the horizon that might mitigate that where, rather than using water you’re using, really, natural gas as the fluid, if you will, to be able to frack with.

And that’s been actually successful in several basins in Canada. And I believe, also, they’re applying some of that technology, I mean early stages in the Eagle Ford where, again, they’re using natural gas re-injected as part of the -- along with prop-ins to be able to frack the reservoir with, really, equivalent results.

So, that looks like that might pay out in the future and, obviously, you’ve got to look at the geologic complexities of the area you’re applying it to. But that’s of interest and something we should continue to follow.

MR. RIVASPLATA: If I can jump in, also, Terry

Rivasplata. The other side of this coin, though, is the perception of the public and what's going to happen with regards to regulations, that sort of thing.

Because there's certainly a conflation that's occurred, at least in the eyes of the public, between injection wells and hydro fracking wells, where there is this belief that a lot of the earthquake activity or micro quake activity that's been seen in other parts of the country is a result of hydro fracking. When, in reality, it's probably the result of these long-term injection wells.

So, the media has not been very good in differentiating between the two and, you know, the potential between the two.

The other thing is that it's becoming relatively obvious, now, that there seems to be a ground swell of opposition to fracking. So, I think we're going to -- you know, that's going to be one of the issues that comes up.

It isn't necessarily whether or not this is having these problems occur but, rather, the perception that they may occur.

So, I think that's where we're going to see some activity. And it's hard to tell exactly what's going to happen here. California is a relatively heavily regulated state and it could be that we'll see action on the part of -- at the State level, with DOGGR, and their new regulations.

But we may also see reaction at the local level. San Benito County, for example, has just adopted a new, relatively restrictive zoning ordinance related to oil well fracking and that sort of thing. So, we may see some local activity occurring along these lines, too, depending on what sort of public input the local decision makers are getting.

COMMISSIONER MC ALLISTER: Well, it sounds like to me we're -- just from the market perspective, it sounds like we're not thinking a whole lot's going to happen with respect to natural gas in the Monterey shale in the near future, anyway.

So, is the reason this is a priority for discussion largely about -- largely to inform sort of the regulatory -- the process of getting the regulatory structure in place so that when that does become a market imperative we're ready for it?

Or what's the sort of -- I'm kind of just hearing that the Monterey shale gas play is not imminent. So, you know, it sounds like Monterey shale for the moment is at least an oil discussion in terms of the energy output of it.

And so what is the imperative to sort of get our heads around the gas issue with respect to the Monterey shale?

(Laughter)

MR. RHYNE: Well, don't everyone rush to the microphone.

MR. HONG: Well, I think that you should set up the regulation because that's the cost of -- figuring out the cost of doing business here. Basically, if you set upon a lot of regulation, that's why you scared a lot of folks out of doing business in California in the first place.

Let's go on the electric side. When you build a power plant here people don't -- the permitting is so onerous it just drives the cost of generation up here.

It's the same thing on this oil play. So, the oil producers decide where they're going to spend their money. If regulation's going to cost an extra -- Leon said it, I mean as one of his analyses, costs are going to go up. And so they just have to decide where they're going to spend their money.

And if you don't have the regulations in place or you're still creating it, it just creates more uncertainty that's all.

MR. RHYNE: So, before we step outside in

California and I'm going to jump around in the order of the questions here, if the Monterey shale isn't likely to be a significant gas resource for California production there are some alternatives that are being discussed.

One of those alternatives is biogas. That poses a number of challenges for not only those who produce the gas, themselves, but I think it also -- and please correct me if I'm wrong, also poses some challenges for the operators of the gas system, itself.

And I'm curious if maybe, Chuck, you can start us off in talking a little bit about what those challenges are.

MR. WHITE: Sure, I'd be glad to. Yeah, it's Chuck White with Waste Management. I've been quite a bit involved in this whole biomethane development issue for the last several years.

Although, when I started looking at this panel and it was talking about shale, I wasn't quite exactly sure what my purpose was going to be.

But we do provide services to the oil and gas shale development industry for waste management purposes.

Waste management -- well, the State of California has quite a bit of resources with respect to biomethane.

Landfills have historically been the major source. There are some other, smaller development projects, but landfills -- there's about 63 billion standard cubic feet per year of methane being generated in California.

And we're required to capture about 85 percent of that right now. There is some fugitive emissions from landfills. There's a lot of debate about how much is fugitive and how much his captured. So, there is quite a bit of resource.

As of this year there's about 350 megawatts have been developed in terms of electricity. There's probably a capability right now of over 800 megawatts, if we wanted to really get into the development of that for that purpose.

Waste Management has developed a lot of these projects. We're running into real problems, though, in California with respect to the air emissions.

The landfill gas to electricity process typically using internal combustion engines, and we use Caterpillar engines. There's some turbines we use as well.

But the air districts, particularly in the South Coast, the Bay Area, and the San Joaquin Valleys are getting increasingly stringent on the NOx and CO emissions from those engines. And so you have to do a lot of pretreatment of the gas and you have to do a lot of post-treatment of the emissions and that really increases the cost.

Plus, a few years ago we were able to get 10 cents a kilowatt hour. It had raised to that level. Now, I think we're down to about 8 or 9 cents per kilowatt hour.

So, the economics are getting real challenging. In fact, we just shut down a landfill gas to electricity facility in Los Angeles because we were losing money on it.

And so I think they're -- where it's going to go on the future is depending on a lot of factors. Probably the whole issue of transportation fuels is the number one thing that is going to be driving the future of development of biomethane in California.

And again, landfills I think are primarily going to be the source of most of the biomethane. There will be smaller projects.

The biggest challenge we've had is getting the gas into the pipelines for distribution. In fact in California, to this day, it's illegal to put even treated, highly treated landfill gas into a pipeline through tariffs that have been adopted by the Public Utilities Commission back to 1992, which were in reaction to a whole variety of factors, but not the least of which was a piece of legislation by Senator Tom Hayden that raised concerns about vinyl chloride in landfill gas.

And there were some issues back, oh, in the 1980s with respect to problems of inadequately treating the gas. But the technology has advanced substantially since then.

We're also looking at doing landfill gas to renewable diesel using the Fischer-Tropsch process. And we think given the higher price of petroleum products that that may make more sense in many cases to do that.

We are looking at wheeling biomethane into California from out of state, and for a whole variety of reasons. One is it's a lot easier to develop it in other states.

We ran into a few problems a year ago with respect to using that out-of-state gas for RPS purposes because of the interpretation of the bucket system and what is your fuel source. And so there was that 2196 that was passed, that put a cutoff date that the Energy Commission has been implementing. And so you're still good, we think, for bringing in gas up to a certain point, but after that date then no more out-of-state gas can be used to meet the RPS.

So, that's constrained for developing out-of-state gas.

We are looking at wheeling gas into California to meet the low carbon fuel standard.

We have actually developed, in California, a project for converting landfill gas into LNG at our Altamont landfill, producing up to about 13,000 gallons of bio LNG that has a carbon intensity of about 5 percent of diesel fuel, so it's about a 95 percent reduction in carbon. It's actually, virtually a near-zero carbon fuel.

And when we first developed that project the price of natural gas was about $12 per MMBTU. By the time we finished building that project it was down to about $7 per MMBTU.

We did look at building a second project, which is still waiting in the wings because we thought it wasn't going to go lower than $7 per MMBTU, and the Energy Commission helped us out with a grant. But then the prices fell, as you know, to $3 per MMBTU, making the economics of finishing that project really problematic based upon the fuel value, alone.

Well, up until a year ago the value of RINS, the renewable identification numbers for under the Federal RFS 2 were on the order of 20 or 30 cents per ethanol-equivalent a gallon. Now, they're up to $1.40.

And the low carbon fuel standard, which was about $15 per metric ton of CO2E equivalent was now up to about $60.

So, everything has changed in the last year. The big question is are these values going to go up because it costs -- it costs about $8 to $10 per MMBTU to develop a biomethane source, whether it's landfill gas or something like that into pipeline quality standards.

If we're only getting $4 per MMBTU, for the fuel price alone that doesn't make any sense.

But if you can get renewable fuel standards, say you have $10 and maybe another $3 or $4 out of the low carbon fuel standard, then you're talking about a $16, $17, maybe more, something between $15 and $20 per MMBTU, you can make some money at that.

COMMISSIONER MC ALLISTER: Well, could you give us an idea of the scale? You know, what's sort of -- you know, you're involved in a lot of landfills across the State.

MR. WHITE: Yes, we have ten gas-generating landfills right now.

COMMISSIONER MC ALLISTER: So, if you were to exploit a good solid percentage of those and be able to clean it up and stick it on the grid, how much gas are we talking about?

MR. WHITE: We've looked at that by both -- I couldn't give you the just California-only numbers, but we have looked at it. Waste management, alone, could provide enough biomethane, low-carbon biomethane to make -- to meet about 6 percent of the low-carbon fuel standard intensity.

We're about one-third of the industry. We think the industry as a whole, by both developing in-the-state biomethane resources and being allowed to wheel in, as long as we're still allowed to wheel in from out of state, we don't want the RPS thing to come back and get us again in the low-carbon fuel standard, which is hasn't so far, about 20 percent can be met with waste-derived biomethane, near zero carbon fuels.

It would take a concerted effort to develop those resources between now and 2020. The other 80 percent would have to come from other sources. Some could come from fossil natural gas, which is a lower carbon intensity, other from electricity, you know, various sources.

So, I think we can make, you know, almost up to one-quarter of the demand under the low-carbon fuel standard. That's going to require switching many of our existing facilities from generating electricity to producing a fuel, so we're going to be pulling back.

But that may make sense because of the high cost of meeting the air pollution control standards that are being imposed by the various air districts that I mentioned.

So, the biggest problem we have right now is the finance-ability of using the low-carbon fuel standard credits and the RIN credits to finance a new project.

As you're probably aware, you don't get the value of the RIN until you have a producer of the fuel transfers the credit to a buyer and the you generate some revenue.

The market historically, until about the last six months, has been very restrictive, other than a spot market for existing fuels that have been developed.

That's beginning to change, for a while variety of reasons, but namely the high price.

And if we can work out a deal where we can generate a five-year commitment to buy RINS and LCFS credits before we actually build the facility, and so we have a guaranteed revenue stream, and the prices would probably be somewhat below the current spot market, we would be able to get into really producing a lot of facilities. It would make sense to make the investment.

One of the biggest struggles I've had within Waste Management, alone, is we're traditional fuel. We know fuel. We know natural gas, we know diesel, we know the markets for that. And our folks really have had a hard time believing that these RIN values and these low-carbon fuel standard credits are real, that they're going to last for a long time, that it's not going to be some kind of switch, you know, for political reasons, or legal reasons. And how the market is going to respond as more fuel gets produced? Is that going to drive down the price?

There's a whole variety of variables that nobody within at least our company is really super comfortable with.

So, that's going to be the big challenge that we face is really trying to find ways that we can work with the people that have compliance obligations to make a commitment to us to buy the products of the -- they don't have to buy the gas, but they're buying the credits. And if we can get a commitment up front, we can build a lot more of these facilities.

COMMISSIONER MC ALLISTER: So, Ivin, I'm sorry to dig on this, I don't want to take away from the rest of the panel, but I think this is a really important topic.

Because, you know, incremental or significant percentages of our long-term goals in the carbon realm, generally, are not real common. So, I just want to make sure that you're plugged in and, even better, industry associations, of which Waste Management is one part, that can legitimately come forward and say, hey, we do landfills, we do biogas, we do natural -- yeah, we do -- we want to participate in this market and engage in the update of the scoping plan at the ARB.

MR. WHITE: Yeah, we're there.

COMMISSIONER MC ALLISTER: I'm sure you're there.

MR. WHITE: Yeah, we are.

COMMISSIONER MC ALLISTER: And as much as possible put some numbers on this and really give a good solid sense of kind of the market issues going forward, and what it would take to develop this resource.

I think just having a real nuts and bolts viewpoint, you know, a well-documented, justified sort of viewpoint of that is really key for the discussion to take place.

MR. WHITE: Well, just a couple of other points is the -- we have suggested the idea that maybe

California should invest in a green bank of some sort, by using some of the revenues from the cap and trade program to create a bank where the State would actually offer to buy RINS and LCFS credits ahead of time, before you build these facilities at a, you know, negotiated price.

Then the State would hold those credits and then be able to sell them to obligated parties.

And we think that would be a really efficient and valuable way to use some of the cap and trade revenues to stimulate this -- to get over the fundability of these programs, so you're not taking the full risk, yourself.

And if California's really behind this, then maybe a little skin in the game wouldn't hurt if we could figure out a way to do that, if those could be backed by the full faith and credit of the State of California to encourage the development of bio resources.

The other point I wanted to make is I've just been amazed because I've been engaged with the CPUC process, under AB 1900, which is meant to open up the utility pipelines for distribution.

We're really fueling our trucks through slow fill, CNG type of operations off of the pipeline. If we’re going to put biomethane into use, we really need to get it into the pipeline for distribution.

And there’s like 40 projects around the country putting high BTU gas in. And the treatment processes are robust. They’re much more rigorous than what you -- from what my understanding is of traditional fossil natural gas conditioning before the pipeline.

In fact, the Air Resources Board just came up with a study that shows that the contaminant levels, the health contaminant levels are far lower in biomethane than they are in fossil natural gas with things like benzene and this sort of thing.

But the utilities are very concerned about getting biomethane into the pipeline, I think because of the history of the vinyl chloride problems in the past, and I think their lack of experience with this.

And my biggest question is why don’t the major utilities have an interest in getting biomethane into the pipelines to help reduce the carbon intensity of the natural gas that they distribute?

Because they, starting in 2015, all of the utilities are going to have a compliance obligation under cap and trade.

But that side of the house hasn’t seemed to be very prevalent in the discussions. Most of it had been the pipeline people that are very concerned, and I understand why they're concerned, about the possible integrity problems, and safety problems of putting biological-derived materials into a pipeline, that it might have sulfur in it.

But the issue is these are like mini refineries and these things shut off if you have any hiccup in the treatment processes and just go back to flaring. They're so redundant that they really clean of these -- the gas to an extremely high level, but there isn't that confidence.

And we haven't seen the other half of the utilities that I would have thought would have a desire to get low-carbon biomethane to help reduce their compliance obligation.

I think part of the problem is that starting in 2015 the utilities are given the credits. They're freely allocated to the gas utilities. It's only after a period of time that they have to start buying more of the credits.

And, plus, I don't think the utilities think there's going to be an increasing demand for natural gas because they're telling me that the amount of natural gas they're distributing is less than it was in 2010.

Your own report shows, I think, about a half a percent and one and a half percent increase between 2010 and 2020.

We could easily -- that percentage could be fully met by biomethane resources.

MR. RHYNE: It looks like Bevin's got --

MR. HONG: Well, I just had a question.

MR. WHITE: Yeah.

MR. HONG: Is the standards by the local utilities more stringent than the interstate pipelines? I mean you've mentioned that it's easier to get it out of state.

And I know that, George, you guys are moving biomethane gas now from the southwest into California.

We don't, personally we don't have any biomethane coming down GTN, down our TransCanada line so --

MR. WHITE: We have actually -- we're putting in medium BTU gas. It's about 50 percent -- well, about 60 percent methane, 40 percent CO2 in a pipeline in Ohio. And we're building a second one right now in Illinois that is just -- they're just imposing the same gas quality standards on us that it would have on any other source.

But here, through the AB 1900, with the CPUC, they want to look at everything that could possibly be in raw landfill gas, and then have to test every single one of those constituents that appears in a landfill in the final product, not understanding the physical chemical treatment process that it can't possibly get there.

COMMISSIONER MC ALLISTER: Yeah, so I guess I kind of want to -- to the extent we can have the -- focus on the technical kind of merits here, I think that's great.

I guess, you know, there are clearly in-state, out-of-state and certain -- certainly, probably, business imperatives as well that probably aren't all that productive to talk about today. At least we're not going to get to the bottom of them right now.

MR. WHITE: I didn't mean to go on and on.

COMMISSIONER MC ALLISTER: No, no, no --

MR. WHITE: This is my life, let me tell you.

(Laughter)

COMMISSIONER MC ALLISTER: I actually think this basic topic is super, super important because the impacts potentially over time are great.

And I guess, you know, I'm aware of some of the discussions. I'm half tempted to invite PG&E, or if there's another gas utility to kind of dive in here, but I'm going to stop myself because there are other questions here that Ivin needs to get to.

MR. WHITE: Yeah.

COMMISSIONER MC ALLISTER: And I guess I would just invite sort of highlighting in your written comments or, you know, whatever you put into the docket.

And that includes some of -- you know, to the extent that what is going on at the PUC is relevant to this discussion, I think it's worth having it on our record as well.

You know, what are the real impediments for getting biogas into the grid and in some way monetizing the credits, you know, up front, or over time, or whatever the kind of business models are most likely to succeed here I think it's really important to understand that so we can help drive policy.

Not just in this IEPR, but just going forward so we can fully engage on this issue and determine how we're going to meet our goals.

So, anyway, with that I'll sort of pass the baton back to Ivin here.

MR. WAYNE: Yeah, I just have one question with regards to this particular issue. Like I said, we'd like clearer policy on the in-state versus out-of-state issues going forward.

MR. WHITE: I'm afraid to ask the question. I got the wrong answer with respect to the RPS. I don't even have it raised with respect to LCFS.

MR. WAYNE: Actually, as you know, it's obviously a transporter of natural gas and, again, we do transport some biomethane. Most of it comes in terms of not so much landfill gas, but really from pig farms.

But there's still a lot of it out there. But what the issue, the impediment is these small farmers, or maybe even fairly large farmers to get enough volume, you know, the up-front capital for the interconnection fee, the treating.

You know, if there was a mechanism to allow us, where we maybe pay the interconnect fee, so long as we have a -- you could apply a surcharge, or it could be passed through our rates, or things of that nature, you know, certainly Kinder Morgan would be interested in that kind of a mechanism.

MR. WHITE: Well, I always thought the utilities would be interested in helping pay the interconnection costs so they could lower their compliance obligation under the cap and trade program, but they don't see to have -- they don't seem to think there's a major issue here, at least in the near term.

MR. RHYNE: Okay. Tim, you looked like you wanted to say something a minute ago. Have you reconsidered?

MR. KUSTIC: No, not on biogas.

(Laughter)

MR. RHYNE: Okay.

MR. WHITE: And I don't want to talk about shale gas, either.

MR. RHYNE: Okay. Well, so we're going to broaden the discussion a little bit to gas as a major portion of the portfolio, but now we're going to step outside of California a little bit.

And I think this actually is a good segue because gas resources outside of California actually form the vast majority of the gas consumed inside of California.

There's a big part of that that is shale gas resources, but there still is a significant portion that are conventional resources.

So, my next question is not written out here -- my next question gets to the relationship to Canadian gas and where Canada, and perhaps TransCanada, and perhaps others are looking to develop additional resources, and whether or not Canadian gas producers are, you know, really aggressively pursuing a connection to overseas markets, or do they see the U.S. market as part of that ongoing sink where you can always sell your goods and services?

MR. HONG: I guess I get to address that question, huh?

MR. RHYNE: Well, as a starter. Obviously, anyone else is welcome to chime in.

MR. HONG: Well, the biggest challenge we have in TransCanada is the Marcellus play. The Marcellus play in the east has been pushing gas and they're not taking gas from Canada any longer.

So, you've seen a shift, a huge shift in the way the gas is flowing. And we need a pipeline map or a map of the United States.

But basically, that pipeline that goes from west to east on the mainline, the volumes are cut in half, even to a fourth.

So, we have to -- as pipelines, what we see that producers are looking for is market. Obviously, the biggest market they want and the most attractive market they look at now is overseas.

I mentioned earlier about the shale play and stuff like that. The Oil Sands is a huge growth area in Canada, now. So, a lot of the natural gas usage is staying right up there.

So, the biggest market that we go towards, now, from Canada is the Chicago market and California, and the northwest.

The biggest problem we see from TransCanada and the GTN system, I've talked to George about this, is when Ruby was built you have a 1.5 BCF pipe and we have a 2.1 BCF pipe that's the cheapest gas right now in the western region, but we have a limitation of how much we can get into California.

So, there's this bottleneck, now, in Malin, in Malin, Oregon.

So, from my point of view we're competing with those guys every day, okay, and Redwood is full. So, that pipeline getting into California is full. The rest of it is filled up with Rocky Mountain gas from Kern River, and from the southwest, and George's El Paso, and TW fills the rest of it.

MR. RHYNE: So, just so I understand what you just said, you say the bottleneck is at Malin.

MR. HONG: Uh-hum.

MR. RHYNE: Is it south of Malin on the Redwood pipeline, is that where the bottleneck physically is --

MR. HONG: That's correct.

MR. RHYNE: -- or is it actually at the hub?

MR. HONG: No, it's on the Redwood path.

MR. RHYNE: Okay.

MR. HONG: And it was created by, you know, California, PG&E, and others, they want a diverse portfolio so they signed up for Ruby and got more of Rockies' gas. That lowered gas prices. Gas is cheap.

George mentioned earlier in his presentation today that there's a lot of pipe. But what's happening now is to build pipe you have to commit to long-term contracts, right.

A lot of these contracts, they have it at El Paso, they have it on TransWestern, they have it on Kern River, they have it on GTN. A lot of these contracts are expiring. People are not committing to long-term contracts anymore in California.

So what are they subject to? All they're doing is buying it from the spot market. Nobody is locking up supplies. Nobody is locking up long-term transportation. It's going to be a huge issue.

I mentioned -- oh, like I said, I had lunch with George. El Paso tried to convert one of their pipelines to oil. They didn't get any takers. But as a pipeline you have to look for alternatives, right, you have to utilize your pipe, getting building determinants, as we mentioned before, but we need people to firm up.

As a gas producer they're doing the same thing. They're looking at the most attractive markets. And like I mentioned earlier, a lot of it's going to be staying up north. A lot of that natural gas is going to be staying up in Canada.

MR. RHYNE: Would you or any of the other panelists say that the massive additions of shale gas has produced what we might think of as an infrastructure, a period of infrastructure instability?

And I think this conversion to oil and the lack of takers may be a good example of where things are going to be built seems less straight forward, and how current infrastructure is going to be utilized seems to be less of a continuation of the past and more a question mark. Would that be a fair characterization?

MR. WAYNE: Well, I think, you know, as far as long-haul pipelines, gas pipelines there probably won't be, really, any infrastructure growth going forward as far as long-haul.

There will be, really inter-regional plumbing. We'll see, like we're seeing in the Marcellus, it's really getting at Marcellus gas further into the northeast, some short-haul pipe being built, or turning pipe around.

For instance, I just got an e-mail today that said that a producer in the Utica had just contracted back-haul capacity on RECs to bring it further into the mid-continent. It's going to be those kind of things that are happening again, optimizing their long-haul resource.

Again, gas infrastructure, there might be laterals built, like interconnections like we're doing on EPNG to Mexico.

But as far as long-haul infrastructure, I don't see much of that. It will be gathering and processing inside the Basin. That's where much of the capital is going towards liquids takeaway, taking that liquid, the NGLs further in the market.

And, of course, oil pipelines, that's really where the infrastructure growth in the pipeline side is, not long-haul gas pipelines.

MR. RHYNE: Any other comments on that?

MR. KENNEDY: Well, you may have talked about this more in this morning's session, but with the divergence of oil and gas in the HIBA crudes in the Southern San Joaquin, I mean the divergent is going to be around the long time.

I could see the industry, you know, using the cheap gas to produce more oil. I don't know if the infrastructure is already there to get enough gas in to meet the needs of the Southern San Joaquin. But it seems to me like that's just a path forward with the current economics, get the gas to, you know, generate the steam to get the oil out of the ground, and while the gas is cheap. It just makes a lot more sense than -- you know, when they originally planning most of their steam floods decades ago, I'm sure they never envisioned a day like this, these gas prices.

MR. RHYNE: All right, so let's talk a little bit more about the marketplace of natural gas. One of the big changes in the natural gas marketplace or potentially big changes is the addition or the kind of the reality of cap and trade becoming a part of the natural gas world in California.

I was curious if any of the panelists could speak to what they see happening in the near term and the long term with the addition of cap and trade, and where they maybe either foresee opportunities or issues arising out of that.

MR. WHITE: Well, I mentioned just a few minutes ago about my surprise that the gas utilities don't seem to be concerned about it because they say they're using less -- they're distributing less natural gas today than they were in 2010. And any amount that they're going to increase between now and 2020 is going to be small.

So, based upon the numbers that I've seen, and from the Energy Commission, it's like somewhere between .5 and 1.5 percent increase.

And so starting in 2015 they get free allowances for a period of time until they have to transition to purchasing them over time.

So, I get the sense there isn't that much of a concern on the major gas utilities. But I'm not a gas utility so I don't know.

Just through the AB 1900 proceedings at the CPUC, it hasn't been the utilities coming and begging for more biomethane in the pipeline. It's really been other folks in the house over there concerned about pipeline integrity and safety issues, which are surely legitimate issues and reasonable concerns.

But I haven't seen any real sense from the utilities that they need to get more lower-carbon methane into the pipeline.

So, the real big driver to me is the Federal Renewable Fuel Standard and California's Low Carbon Fuel Standard that is really driving the transition to using this as a transportation fuel.

MR. HONG: I agree with your comments, Chuck. I mean basically what I've seen -- I follow the par market, too. And basically what happens is -- you know, in the old days you could do -- you figure out the cost of gas, you multiply it by a 7 heat rate and you get the cost of power.

And basically what I've seen now is the cost of power is a little bit higher than a 7 heat rate.

So, basically, what they've looked at, what they've done in the power industry is it appears that the cap and trade is basically a tax and they've increased that to consumers. So, they've raised the power of power.

MR. WHITE: The price of power.

MR. HONG: The price of power, yeah.

MR. RHYNE: Okay, any other comments?

All right, what about if we look at another aspect of the gas markets, one of the -- one of the propositions that's been moving forward is the idea of having a more frequent gas domination schedule that would align gas and electricity, make it a little closer and make that be a little more harmonized.

Any thoughts from the panelists on what that might mean going forward, how likely that is to take place and under what circumstances might we deal with some issues associated with that.

MR. HONG: On the gas side I've seen people use the utilities as a bank. So, basically, the way you have nomination schedules on PG&E and SoCal Gas there's a lot of flexibility.

If we -- in fact, in George's pipeline in El

Paso don’t you guys have hourly nominations now?

So, on their pipeline, and we’ve looked at this also, basically, you have to nominate how much you’re going to use per hour.

But when you go into PG&E and you go into SoCal Gas you have 30-day balancing, unless they call and OFO. You have every right to feed your gas back into your system any time within that time period they’ve set, so a lot of flexibility on that.

MR. RHYNE: Okay, any other thoughts or comments on that? No?

I did have a follow-up question from earlier. We’re getting close to wrapping up. It occurs to me we mentioned that folks aren’t buying at contracts so that we’re not seeing that new infrastructure.

And this is really for George and Bevin, primarily, are you hearing anything from customers as to why they’re not taking those contracts?

MR. WAYNE: Well, I mean that in general, you know, as we look at the State of California, they’ve been very successful in terms of their demand side management really controlling the growth of natural gas. The natural gas projections that you all show and I concur is it’s flat to declining.

And you’re growing storage to be able to manage your peak day needs, and you are over-piped like I said the 6 BCF per day, on average, consumption with 10 BCF a day of interstate pipeline capacity.

So, they feel like they have the ability to go short-term firm, like we call it, month-to-month, and not sign up for long term to be able to fulfill their needs.

Again, it’s a risk management game, basically playing a risk management bet to the day where there might -- if there’s a day when there’s peak demand, or as the gentleman from PG&E said, you know, if we look at most of these long-haul systems like a straw, you have demand further upstream on the pipe that’s not necessarily a given that gas will flow at the very downstream end of the pipe.

We have other forces, like Mexico, other upstream forces that are absorbing that capacity and that capacity and ability to transport gas may not be there. And that’s sort of the long-term bet that California is playing.

Right now they think they can go the short term, the month to month, and not sign up for the long term. We’ll just have to wait and see if that pays off for them.

MR. HONG: I have just a little bit to add on that. I mean what happened the last time that we had a pipeline interruption or explosion it caused prices to jump up. But if folks had locked up their supply in firm transport, they wouldn't have been exposed to that.

It's exactly what George said, people are just buying on a spot market, buying at Citygate and they're just gambling that the gas will be there at a cheap price.

MR. RHYNE: Okay. All right, so my final question, actually, is for all the panelists. I'll ask you to put on your thinking caps here.

Ten years ago we were -- we thought the world of gas supply looked different. All of us sitting around the table might have projected a very different trajectory than where we are today, and it had to do with kind of a growing, an unseen kind of trend towards getting at shale gas. Shale gas, by the way, that we've known exists in the ground for a long time, but really hadn't gotten to the point where it became a viable part of the market.

So, my question to each of the panelists, and I'll ask you to go in turn, and Terry, I'll ask you to start, if -- when you look at the gas marketplace, the supply portfolio, the gas marketplace, what do you think the next disruptive element might be and why?

In other words, there's all this stuff that we're thinking of with regard to the trends. But what's likely to be the next thing that disrupts that trend and moves us in a new direction?

MR. RIVASPLATA: Boy, that's a tough one. It's even tougher since I didn't have this on. That's a tough question.

And in California I think the first answer has to be regulations, you know, and what potentially could be coming down the pike with regulations.

You know, whether or not we loosen up regulations on pipeline transmission, whether or not somehow the California Environmental Quality Act becomes invoked in some of these activities, where it isn't now, that's where I would see the potential challenges.

Because it's hard to predict what sort of regulations California will come up with next. And at the same time, as we become more realistic in our approach how we go about trying to streamline what our regulations are.

Because I think that there is a push in certain quarters to streamline our regulations and I think that will happen somewhere along the line, but it's hard to predict exactly when that will be.

MR. KUSTIC: Well, we're in the process right now of creating more regulations on hydraulic fracturing in California.

(Laughter)

MR. KUSTIC: They’re not necessarily targeting the gas market. But, certainly, additional regulations always add additional costs and some marginal operators, you know, may go out of business and that’s the realities of additional regulations.

But, certainly, our regulations I don’t think are so onerous -- excuse me -- thank you -- onerous on industry that it’s going to stop hydraulic fracture stimulation in the State.

They are, for a large part, capturing the best practices that industry now does.

But when it comes to the overall gas market and production scheme, and what’s the next potential upset, you know, I think looking at it nationwide there is a growing environmental concern over the development of shale gas.

But industry’s been very well versed in adapting their operations to address environmental concerns.

So, certainly they continue to do that throughout the country and I think that will continue, so I don’t see there being -- there will be greater and greater environmental concerns, probably greater and greater regulation and legislation dealing with it.

The Federal government’s talking about regulating hydraulic fracturing at a Federal level, rather than the state level, so some of those battles will be played out.

But I still, you know, with the incredible demand that the nation has for energy I just -- I don’t see the industry going away. I don’t see the natural resource not being developed. It might be developed at higher marginal cost, certainly.

So, as far as what’s the next like shocker to the gas market, it could be that when -- it could be many years down the road when the limits of the shale market are finally defined. But right now the limits are fairly wide open, so it could be a long, long time before that next challenge comes up.

MR. RHYNE: Thank you.

MR. WAYNE: Yeah, this is obviously a very tough question. I’ll get out my crystal ball. But let me go back in retrospect. You know, I look back ten years and what the crystal ball or what the people were saying is that we were -- I think I had a presentation, we were expecting, by this time frame, 14 BCF a day of LNG imports.

Now looking forward, we’re talking about maybe four terminals in the Gulf, maybe one on the East Coast, one of the West Coast. Maybe the total in North America 5 to 6 BCF a day of net exports so, you know, it just completely turned itself on its head.

But the reason -- but you've got to ask yourself the question of what brought us to that point, what was the market signal that brought us to that point? The market signal was price.

I mean price had gotten up to a level that stimulated investment, at least on the upstream EMT side. They got innovative and they found the solution, and that was the discovery or this prolific source of shale gas.

So, you know, the market is efficient in that way to be able to create that market signal to where you can innovate and take advantage of it.

Regulation is very important and it really plays into that where it doesn't upset that apple cart.

I can only stress that, you know, very well thought out regulation and its implications is important so we don't squander this great resource that we've found.

You know, if we look at -- again, a small microcosm of that is what's happened on the oil side. You know, people talk about the Keystone pipeline and other things. Well, keeping the Keystone pipeline out, I mean a case in point, there's issues, protests about that. I'm not saying I'm pro or con. But, you know, what was the market solution? More rail. Well, was that good?

Well, you know, we saw a rail car, you know, accident in Quebec just a week or so ago. That was an implication -- that was the fallout. You know, was that poor policy making or again, where pipeline transportation has always shown to be the cheaper, safest form of transporting that volume of material. But, yet, the policy made it to where the market chose rail.

So, it's again, thinking through those kind of implications are important because you might get the kind of response that you don't want.

MR. WHITE: Yeah, I can say we just love the natural gas industry because we -- number one, it's a big business for us to provide waste management services for the drilling and production of natural gas that's gone up in Pennsylvania and Ohio. Not so much out here.

But also, the low price of natural gas. Waste Management has made the commitment that we're going to convert 80 percent of our fleet to natural gas between now and 2020. We were basically a diesel company until a few years ago, 2008 is when we made the decision.

In 2011 we had 1,000 natural gas trucks. In 2012 we had 2,000. By the end of this year we're going to have close to 3,000 natural gas trucks.

We have 32,000 vehicles nationwide, 18,000 of those are heavy-duty vehicles. We hope to have 20 percent of those -- 80 percent of those heavy-duty vehicles converted to natural gas for a whole variety of reasons.

I think the biggest challenge, with respect to the biomethane that I mentioned is that the only way that we're going to be able to compete and produce biomethane to meet other policy needs, like low-carbon fuel standard in cap and trade, is to have these programs like the Renewable Fuel Standard, and Low-Carbon Fuel Standard stay solid and strong so we can actually -- you know, there's an incentive to invest.

My biggest fear is because both the RFS2 and LCFS are political, legal constructs that the political and legal forces out there could cause them to be weakened in some way, shape or form.

And I would hate to build 10 to 15 additional biomethane production facilities in the next few years to meet the Low-Carbon Fuel Standard, only to find it disappear and I've got these stranded assets that are worth next to nothing.

So, that's the number one fear I have. I certainly want to work with the oil companies and help them with their compliance obligations. But if they can help me, making sure that I can continue to deliver what they need to comply, then I would be -- you know, hopefully, we could both be happy at the end of the day.

MR. HONG: George, thanks for mentioning Keystone.

(Laughter)

MR. WAYNE: You have an interest in that?

MR. HONG: Just a little bit.

The biggest thing I learned, around a month ago, was that there were oil sands coming into the Chevron refinery by rail, from Canada, all the way to the Bay Area. And that was -- I couldn't believe that so -- so, Commissioner McAllister, did you know that?

COMMISSIONER MC ALLISTER: No.

MR. HONG: Yeah, I'll forward the article to everybody. I didn't do the research. There was other, you know, California reporters that delved into that. But to answer you or --

COMMISSIONER MC ALLISTER: Interesting to know who that -- what publication that is.

MR. HONG: Okay.

COMMISSIONER MC ALLISTER: That’s kind of important.

MR. HONG: Yeah, it wasn’t from Canada.

(Laughter)

MR. HONG: The biggest thing we see in natural gas is I -- you know, California’s always been the most progressive state, but they’re really not big fans of natural gas.

You were at a conference just last Monday at UCLA, and I think I’ve heard for almost eight hours how what we should be doing, instead of burning natural gas, was demand side management, energy conservation, renewables. And what the biggest frustration I have is I don’t think people put their pencil onto the paper and figure out the numbers.

And when you look at the numbers and when you talk about gas-fired generation, say, and it’s only 20 percent of the portfolio in California, right, this gas-fired generation. But it’s also on the margin, it’s also the cheapest.

So, there was another thing at UCLA, the LADWP was there. And what did they say? They said their rates were going to be doubling.

And that’s the rate shock I’m waiting for to happen, guys. I haven’t seen it. It hasn’t been talked about much at all.

I think the CPUC, and PG&E, and all of the utilities are keeping this low. They’ve been trying to talk about how to restructure rates and things like that, but that’s coming to the horizon.

So, as for natural gas, you know, we’ll adjust. You’re seeing it already. With all the renewables coming on there’s a peak now in the morning. The only thing that can run in the morning with flexibility now is gas-fired gen.

There’s going to be storage they’re talking about, but that technology is not here yet. The batteries, it’s not here yet.

So, gas-fired gen will be the one that’s going to be peaking up and down because that’s the technology we have right now.

COMMISSIONER MC ALLISTER: Well, I kind of have to just jump in and put this in context.

I mean, so, you know, there are definitely a certain set of numbers. You know, rate pressure is -- you know, it looks like it’s a real thing. And I think, you know, nobody wants to make that -- you know, sort of put that out there until it’s clear because there’s still a lot of uncertainty.

And, certainly, we’ve taken coal off the table in California. We've got -- you know, one of our two nukes is down and will stay down.

So, you know, when you're talking about sort of traditional resources, there aren't many left on the table.

And, certainly, the one that is front and center is gas. And that technology's gotten a lot better, it's cleaner, it's more efficient and certainly dispatchable.

At the same time, you know, those heavy capital investments in that kind of infrastructure, you know, are large.

And the loading order in California is there, it's policy and it says that demand response and energy efficiency's number one. And, in fact, traditional fossil's number three.

So, you know, there's a lot of contested ground between those two things and trying to figure out, okay, well, renewables, what sorts of -- so, they're actually quite cheap on a per-kilowatt hour. The large-scale renewables, solar and wind, are actually very small per kilowatt hour, but cost do they impose on the grid.

So, there's all these -- you know, due to their non-dispatchability, et cetera.

And what other new technologies could compensate for that storage of all types.

So, anyway, this is not the subject of today, but I think we need to really understand the long-term implications.

So, you talked about one set of numbers, one type of numbers. The other type of number is, you know, if we count the molecules and we're looking at 2050, how much carbon can we be emitting.

And even natural gas, with all its benefits, you know, you've got to be very cautious at how much you invest today, or in the near future for these long-lived capital assets that are going to be around in 2050 producing molecules and injecting them into the atmosphere.

So, the idea is not to put all of the eggs in one or the other basket, but to choose judiciously, you know, based on, admittedly, not full information because some of these technologies are newer than others.

The advantage natural gas has, it's been around for 100 plus years and, you know, we know it, engineers are comfortable with it.

But all of these technologies deserve, you know, proper due diligence, and comparison, and contrasting, and sort of to figure out what the mix and the diversity ought to look like that gets us where we need to go for the long term.

So, I just wanted to sort of back up and put that into context.

MR. WHITE: We just -- we like to look at the natural gas industry as kind of an interim stepping stone to biomethane, so just wanted to make sure that was clear.

(Laughter)

MR. RHYNE: I appreciate that perspective, Chuck, it's good to know.

(Laughter)

MR. RHYNE: So, I want to -- this basically concludes the panel. I want to thank the panelists for participating this afternoon.

It also brings us to the closing segment of our workshop today. It's been a busy morning and a busy and thoughtful afternoon.

And we've had, at a couple points today, people step to the microphone there in the middle and ask questions, clarifying questions on particular presentations.

We've reached a point in the day where we're going to open the floor, first of all to the folks in the room, then we'll go to WebEx participants, and then finally to phone participants.

And we will ask for public comment at this point.

So, if you have comments you would like to make, you can either step to the podium, or if someone’s there you can just step to the side and we’ll recognize everyone in turn.

If you have a particular question for staff, or for one of the panelists, we’ll try and answer that with some brevity and clarity.

If we can’t answer the question today, we will research the answer, and we will answer the question as a part of what goes up in the written docket.

So with that we’ll open the floor. First of all, if there’s anyone in the room who has comments or questions, please step to the podium now.

All right.

MR. BRATHWAITE: I promise not to be too long or difficult.

Okay, Tim, my question actually is for you. I’m Leon Brathwaite and I work here at the Commission.

Could you please just kind of update us on the status of the development of the hydraulic fracturing regulation?

MR. KUSTIC: Sure. It started over a year ago, now, where we had seven information gathering workshops throughout the State, where we went to different locations, gave about a half-hour presentation on hydraulic fracturing, what it is in California and then we seeked input.

After that round of workshops we released a discussion draft of the regulations in December of last year, and then held five more workshops on the material and the discussion draft and, you know, things outside the discussion draft that interested parties thought should be in the regulations.

We are this summer -- somewhere in the next two months, we will be starting the formal rulemaking process on the regulations. And we anticipate that to take probably close to a year. It has to be completed within a year, but we have already received upwards of 20,000 comments on hydraulic fracturing.

So, we -- you know, a lot of those are going to be -- you know, they're generated comments. But even the un-generated comments are quite voluminous.

So, we know we will receive extensive comments during the rulemaking, so we anticipate it could take close to a year before the rule is final.

MR. WAYNE: Are those mostly water-related comments, issues or --

MR. KUSTIC: No. I mean they're across the board. They're water, air, well integrity issues, disclosure issues, notification issues. It's quite a gamut, really.

MR. BRATHWAITE: Tim, thank you.

MR. KUSTIC: Sure.

COMMISSIONER MC ALLISTER: Are you doing any analysis along these lines of sort of the fugitive methane type of issues? I imagine some of the comments, at least, are around that issue. Sort of what regulations -- there's sort of -- you know, looking at the technical underpinnings of that question and sort of including in regulations the mitigation?

MR. KUSTIC: Well, I mean our hydraulic fracturing regulations are not specific at all to natural gas or oil, it covers both.

But, you know, our existing regulations say you can't have gas leaks. You can't have leaks, and spills and things like that.

So, you know, it's kind of the standard right now is zero. So, that's going to maintain so we're not really analyzing less than -- or more than zero.

MR. RHYNE: All right, thank you.

Any other questions or comments in the room?

All right, so it looks like we have no more questions in the room.

I'll ask if there are any questions or comments on WebEx?

MS. KOROSEC: We have nothing on WebEx, but we do have two callers that I'd like to open their lines, that are phone-only, then we can see if they have any questions.

MR. RHYNE: Okay.

MS. KOROSEC: So, Linda, would you mind going ahead and unmuting their lines?

Oh, we only have one caller. All right, phone caller, your line is open in case you would like to make a comment or ask a question.

All right, hearing nothing --

MR. RHYNE: All right, so that wraps up our presentations.

At this point I'll ask Commissioner McAllister if he has any closing remarks?

COMMISSIONER MC ALLISTER: You know, I think I've gotten in the scrum enough already, so people kind of know where I sit on these things.

But, you know, really, again, I always learn a lot from the workshops that Ivin puts together because they're very high-level panelists and a good diversity of perspective.

We did actually try even to get more diversity of perspective in today, but we weren't quite successful at that, trying to get NRDC, kind of to get their perspective, and then WSPA on the other side.

So, anyway, some future, you know, moment hopefully we can have -- include them in a discussion as well.

So, you know, I don't have any specific comments on the substance, just wanted to say thanks to the panelists, both this afternoon and this morning, and to Ivin and the team, and Suzanne and the team on the IEPR side for putting together another good workshop.

And really hoping, in particular, that some of the issues that came up, that there was a diversity of opinion on, it would be great to get some of that stuff on the record regarding biogas and some of the related issues.

So with that, I'll pass it back to Ivin to close it down.

MR. RHYNE: Okay, so to close out the workshop, first of all, as mentioned there is a comment period. We would ask for comments to be sent to the e-mail address that you can see on the screen, docket@energy.ca.gov.

It's important that you include your name, the organization name and docket number, which is 13-IEP-K, which indicates that it's the natural gas assessment portion.

And I'll ask you also to cc myself, Ivin.rhyne@energy.ca.gov.

There is an address if you feel, you know, a little bit nostalgic and you want to use snail mail, by all means that still works, as far as I know.

So, we definitely want to encourage that.

It's really important to us that if you think that our scenarios somehow use values that perhaps should have more information, or perhaps should be different values that you capture that comment, that you send it to us.

And we find those comments to be exceptionally helpful.

I want to especially thank PG&E for their thoughtful comments at our last workshop, which pushed us as a staff to look at issues around the accuracy and uncertainty of the forecast, as well as understand the LNG import, and net import/export location.

We, as a staff, found that very useful to go through and understand.

And we hope that we get further comments from this workshop that are just as helpful.

I think that in closing, my last statement needs to be I want to recognize the Natural Gas Team, most of which who have been rather quiet today, just kind of sitting off to the side. They really worked very hard to put this together today.

We have a new supervisor to the team, Linda Spiegel, who hopefully means that I won’t be up here quite so much, you know, making a spectacle of myself.

And the rest of the team, they did a wonderful job in making this happen and really appreciate the work that they did.

So with that I think we will close the workshop. Thank you all for attending. Please drive, fly, boat or paddle, or however it is you get home, please do so safely. Thank you.

(Thereupon, the Workshop was adjourned at 3:20 p.m.)

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