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

In the matter of,	)
	) Docket No. 13-IEP-1K
	)
Preparation of the 2013	)
Integrated Energy Policy Report	)
(2013 IEPR)	)

California Energy Commission Staff Workshop on

Natural Gas Issues and Forecast Scenarios

California Energy Commission
Hearing Room A
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9:09 A.M.

Reported by:
Tahsha Sanbrailo

<u>COMMISSIONER</u>

Andrew McAllister, Lead Commissioner

Pat Saxton, his Advisor

<u>STAFF</u>

Ivin Rhyne, Office Manager Electricity Analysis Office

Melissa Jones

<u>Also Present</u> (* Via WebEx)

<u>Presenters</u>

Greg Mayeur, California Air Resources Board

Brad Bouillon, California Independent System Operator

Roger Graham, Pacific Gas & Electric Company

*Manuel Rincon, Southern California Gas

*David Bisi, Southern California Gas

Robert Kennedy, Natural Gas Analyst, California Energy Commission

Peter Puglia, Natural Gas Analyst, California Energy Commission

Tim Kustic, California Department of Oil, Gas, and Geothermal Resources

Miriam Rotkin-Ellman, Natural Resources Defense Council

Leon Braithwaite, Senior Natural Gas Analyst, California Energy Commission

<u>Public Comment</u>

Chris Mclean, California Energy Commission

Katie Elder, Aspen Environmental Group

Mia Vu, PG&E

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APRIL 24, 2013 9:09 A.M.

MR. RHYNE: Welcome to the 2013 Natural Gas Issues and Forecast Scenarios Staff Workshop for the 2013 Integrated Energy Policy Report.

My name is Ivin Rhyne and I'll be kicking off the workshop today.

We have just a few items of housekeeping before we get things started. This conference is going to be recorded.

So, if you're not -- for those of you not familiar with this building, the closest restrooms are located just outside the entrance that you came in and to your left.

There's a snack bar on the second floor, under the white awning.

And lastly, in the event of an emergency and the building's evacuated, please follow our employees to the appropriate exits. We'll reconvene at Roosevelt Park, located diagonally across the street from this building.

Please proceed calmly and quickly, again, following the employees with whom you are meeting, which would be myself and several of the staff who will be presenting a little bit later, to safely exit the building. Thank you very much.

And with that, I'll turn it over to Commissioner McAllister for opening comments.

COMMISSIONER MC ALLISTER: Oh, I want to thank everybody for coming. Those of -- it looks like we may have some people on the Web, as well, and definitely for everybody in the room thank you very much for your time.

This is our ongoing IEPR workshop series and, really, we're continuing to lay the foundation for the forecast for natural gas, today. It's super important for a number of reasons that you all know well.

And, in particular -- well, I'll let Ivin -- this is a staff workshop, so I'm not presiding directly here and appreciate Ivin and his team taking the lead on the organization, and really taking their with a seriousness to make sure that we have a solid foundation for the forecast, and that it's all well-documented, well-explained, and very well sort of conceptualized with input from all of you, and other who submit written and oral comments.

Really, the best process, so that's the best way to get everything down so that we have accountability, ultimately, so we have transparency, and an understanding, broadly, of what the process is and it results in a forecast that will be generated as part of the IEPR.

Because as we all know, it’s a foundational document for the State and it goes to a lot of different places, and it’s used, you know, beyond the State for other work, to inform other work that is also setting policy around the country.

So, anyway, thank you. And with that, I’ll pass it back to Ivin and thank you, again, very much for coming.

MR. RHYNE: Thank you, Commissioner McAllister.

So, with that we’ll jump right in and before we turn it over to the real experts who are going to talk through some of the issues, as well as the modeling and scenarios, really wanted to talk about, first of all, the purpose of this workshop today.

First of all, we’re here to explore important and emerging natural gas issues. These issues help us to understand what may be coming down the pipe and help us to make better analysis. But it’s important for us to get that information from experts in the field, and so we’ve invited a number of experts from outside the Commission to share their insights on a number of issues, which I’ll talk about in just a moment.

The second purpose of this workshop is to present model scenarios. And I’m going to emphasize the term “scenarios” or “cases” depending on how you want to look at it. But, really, to start with we’re looking at understanding how would we incorporate some of these possible future states of the world into the tools that we have?

In this case, a general equilibrium model of the natural gas market that covers the entire North American Region.

Finally, the last and perhaps most important part of this workshop is to gather stakeholder feedback. Your input, meaning the input of those here in the room, and those online that we gather through the spoken discussion today, as well as written feedback at the post-workshop is really critical to make sure that we have addressed the issues correctly, that we have provided responsive feedback on issues, and made sure that we have looked at this in a more holistic way, rather than just from the confines of these walls.

So, it’s important for us to get that feedback and we really look forward to hearing from you today, as well as in the future as you file your written comments.

So, first of all, the major gas issues that will be discussed today. Cap and trade for natural gas. Cap and trade is obviously something that has recently been implemented for electricity in California.

However, according to State law, natural gas is the next to come under cap and trade. And we’ve invited a representative from the Air Resources Board to come and talk about that.

Next is the interaction between the gas and electric systems here in California. One of the important elements of bringing variable or intermittent renewable generation online is that it poses an operational challenge that California has already started to address, and we think that are actually ahead of most of the rest of the United States.

But we’ve actually invited a representative from the California ISO to discuss that issue.

Natural gas storage is an important piece of how the natural gas system is operated, both now and in the future, and we think it may play a part in decision making in the near future. And so, we’ve invited representatives from gas utilities to talk about how natural gas storage plays into their thinking.

And, finally, one of the major national issues that has really captured the discussion in the natural gas field is the use of hydraulic fracturing to extract natural gas from reservoirs where it was previously uneconomic to do so.

This hydraulic fracturing activity has implications for where in the United States natural gas is extracted from, how much is available domestically and even, perhaps, where in California gas may be extracted from in the near future.

And so, we’ve invited representatives from both the Department of Gas Geothermal and Oil Resources to talk about what is going on in their rulemaking, as well as a representative from the environmental field, from Natural Resources Defense Council to talk about their viewpoint, as well.

Following those discussions, we’ll be moving on to a discussion of model scenarios. How do we translate those key issues into something that we can quantify and put into a model.

Now, I will be careful to say, and you’ll hear me say again later, that some of these, in fact many of these issues are not easily translated into a model input. And we understand that and we think that’s actually perfectly fine. We don’t intend to capture everything all at once, but where we can we’re going to attempt to do so.

So, we’re going to break these into three groups of cases. The first three cases were discussed at a February 19th workshop. They are the Integrated Energy Policy Report common case scenarios.

These are a set of scenarios that have shared input and output assumptions and elements across natural gas, electricity, and transportation fuels. There have been minor revisions and updates to those scenarios based on feedback following the February 19th workshop, and so we're going to share the gas portions of those revisions.

The second group of three scenarios is a state and national uncertainties cases. This is a fairly broad brush that encompasses a number of elements that we'll discuss. Some of these are policy elements. Some of these talk about innovation rates, how quickly things are improving with regard to technology for extraction of natural gas. So, this is broad-based.

And, finally, the last four cases we're going to discuss this afternoon are shale production on certain cases. Shale, which is the resource from which hydraulic fracturing draws the gas is, again, one of those major question marks going out into the future.

And so, we explore four cases that allow us to ask what if. What if shale is perhaps extremely abundant for the foreseeable future?

What if the abundance that we think we see there is perhaps delayed some number of years, what does that do to the natural gas marketplace? And we've got a couple of more along those lines and we'll share those, as well.

Finally, I want to talk, once again, about stakeholder input. Participation really is the key to improving these results.

We’ll ask, after each presentation, that if you have a particular clarifying question, please feel free to step to the microphone. When you do so, please state your name and affiliation for the court reporter, who is here. If you have a business card, please share that with her, as well, so that we can get the spelling of your name and your affiliation correct.

After each topic area, that will be the appropriate time for discussion for us. So, for example, where we have one presenter we’ll just go from clarifying questions right into the discussion topics.

However, if we have two presenters, for example in the storage area where we have two presenters, we’ll ask that the clarifying questions come after each presentation. And then after both have presented, we’ll open the floor to discussion.

We will have an open comment period before lunch and we’ll have another open comment period at the end of the workshop.

We also want to make sure that written comments are encouraged. What is said here is translated into the transcript and we will certainly pay attention to it.

But this is one of those -- this is an element of staff work that requires a great deal of information and data, and so if you have that data or information at hand, or if you would like to recommend values, numbers, ways to translate some of these important issues of the day into assumptions, we really want to encourage you to do that. And doing it in the form of written comments really helps us capture that in your words more correctly, and understand your viewpoint.

So, we would really encourage you to do so.

With that, that is the close of my introduction. I'll ask if there are any questions at this point in the morning, before we get started with our first presenter?

All right.

(Check for online participants)

MR. RHYNE: Thank you.

And I'm seeing none in the room and it looks like there are none online. I'm sorry, one note, if you're on WebEx and you have a question for us, you can type it in the chat box and we have a staff member here paying attention to that.

And so, we can capture those at the end of each presentation, as well.

So, with that, I'm going to bring up our first presenter, who is Greg Mayeur, with California Air Resources Board. And we're going to bring up his presentation. Here we go and you just forward with that button right there.

MR. MAYEUR: Thank you. And thank you for inviting me to come over here to give a brief talk about the California Cap and Trade Program.

My name's Greg Mayeur. I'm the Manager of the Program Operations Section under the Cap and Trade Program at ARB, and I also wrote most of the NOP and GAAP reporting requirements under our mandatory reporting in my previous job. So, I'm fairly familiar with the NOP/GAAP sector and all financial aid questions.

All right. I assume most of you in the room know what Cap and Trade is, but I thought I'd go over a very brief overview just to get everyone on the same page.

So, Cap and Trade is one of our suite of measures to reduce the greenhouse gas emissions under AB 32, which also includes the RPS, the Low-Carbon Fuel Standard and managed control measures that ARB has implemented.

The Cap limits total emissions from all

regulated sources. They're mainly large industrial sources and we'll talk a little bit more about those later. And the Cap declines over time as we reach our goal of 1990 emissions in 2020.

Participants are on the trade-approved GHG emission allowances which creates flexibility and reduces the compliance, and it works together with command and control measures, which are our traditional measure for reducing emissions in California.

The goals of the program, like I said, are to reduce greenhouse gas emissions. We want to price emissions to incentivize change. We don't want to force change, but we want to spur innovation, and low emissions and efficient technologies. It complements existing programs to reduce smog and air toxics. We always are looking for co-benefits with all of our programs.

We want to ensure AB 32 reductions for GHGs are realized through a strict limit and we want a flexible mechanism that allows all covered entities to find the most cost-effective mechanism to comply with the regulation.

So, who's covered? We have large stationery sources at or above 25,000 mega tons of CO2e a year. Those are mainly large industrial sources, demand facilities, the firing gas producers, electricity generation and importers.

And we are going to cover, upstream, the small combustion emissions at the fuel provider level, so that’s the transportation fuels and the residential, and commercial use of natural gas, which you guys are interested in, which will be coming into the market in 2015.

The requirement of the covered entities, they must register with ARB, they have to report their emissions annually, they have to surrender allowances and offsets to match their compliance obligation at the end of every compliance period.

The reductions are program-wide, not facility-specific, so each facility does not have an individual obligation. It’s an obligation on the State, as a whole. They must comply with recordkeeping and market rule verifications that are the requirements of the regulation.

So, for the local distribution coming, the natural gas distributers, the covered entities are going to be your public utility and gas corporations, like PG&E, San Diego, Southern California, Southwest and West Coast, and then the publicly-owned natural gas utilities. These are just a few examples, like municipalities, municipal utility districts, joint power authorities.

And then we also capture the intrastate pipeline so that we have pretty much a hundred percent coverage.

Interstate pipelines are only required to report to us, they aren't covered under the Cap. But we do not believe that they would have a compliance obligation, otherwise, because they deliver to mainly large facilities who are covered under the Cap, already.

So, here's how your compliance obligation is calculated. You know your receipts at the State gate -- or I'm sorry, receipts at the State border or city gate. For like PG&E it would be the State border. For a municipality, it would be the city gate.

Then you would add in your receipt from the in-state production, and then volume of gas in storage. Not every entity would have those.

And then you also add in or subtract out your in-state receipts and re-delivery to utilities, intrastate and interstate pipelines.

And then you do not subtract out the deliveries to covered entities. That will be done by ARB because we're the only ones that will know all the covered entities. There are a few unique cases where the volume of natural gas doesn't make it covered, but they have other fuels or other process emissions on site that will push them over the threshold, so that they will have the compliance obligation on the natural gas in that gas, and not the utility. And we will be able to subtract that out from the utility's covered emissions.

Some of those are -- we're looking at adding some additional facilities where the processed emissions bring the -- over the combustion emissions, so those guys will come in even though they have combustion emissions below 25,000.

So, the calculation of the compliance obligation is based on a million BTUs of pipeline quality natural gas at each point. If the gas is outside the pipeline quality, you're allowed to report it using our standard methodologies for di minimis amounts, which are less than three percent.

If the outside pipeline quantity is over three percent, then you're going to have a carbon sample to gas to report its emissions.

And we cover emissions from CO2, CH4, and they're all default emission factors in most cases. And CO2e, or CO2 from biomass-derived fuels are an example, or biomethane.

The economic impact of natural gas, ARB's inventory estimates that the emissions from the natural gas suppliers will be 50 million metric tons in 2012, slowly rising to 56 million metric tons in 2020. And the impact on the cost from the Cap and Trade Regulation, at $15 an allowance, will be about a seven percent increase for residential customers, and eight percent increase for commercial customers, and a six percent increase for industrial customers.

And here are the people that you can contact with any questions, if you think of anything outside of this program. Elizabeth is the Manager of the Amount of Allocations, and they're currently discussing mechanisms, potential mechanisms for free allocations to the natural gas utilities. So, if you have any questions on that, she would be the appropriate person to contact.

And Steve's Operations Chief and he can answer any questions or direct you to the right person.

Any questions?

MR. RHYNE: All right, thank you, Greg.

Okay, our next topic is a discussion of the gas/electric system interaction. We have Brad Bouillon from California Independent System Operator.

And I will step out of the way to enable Brad to step to the mic.

MR. BOUILLON: Thank you. My name is Brad

Bouillon. I am the Director of the Day-Ahead Market and the Real-Time Operations Support Groups for the California ISO. It’s a recent job change for me and some of those responsibilities include the gas and electric coordination.

And while I was new to the official responsibility, aspects of my job, which I’ll get into as I go into the slide presentation, have been actually going on for quite a while, and so most of it is not new. Some of the areas in the regional piece that I’ll discuss in the later slides will be stuff that I’ve just recently got into.

The history of what transpired to bring up the coordination to the forefront and get more people involved was in February 2011 there was a cold weather event in the Southwestern United States. It resulted in production restrictions and those production restrictions of natural gas reduced the capacity to primarily ERCOT, which is the Texas ISO equivalent, and they suffered some significant outages as a result of that event.

Here, in California, we actually did suffer some reduced gas capacity, but we did not experience outages. So, we didn’t have the problems that Texas had, but we were impacted because we do draw our gas supply from the southwest.

As a result of that, FERC stepped in and said we want to issue a notice soliciting comments on aspects of gas and electric coordination. This was about a year later. And they were very interested to see where everybody stood. They didn't have a good view of the whole picture of what was going on, so they wanted to just found out. It was information gathering.

And to that extent, 79 entities across North America responded with various perspectives, as well as identifying issues, and challenges they were seeing.

The important note here is that issues vary by region. And there are different regions, from a gas stand point, in the United States that have significant impacts on what's going on.

And so, while I'll go into California as I start to drill down more related to us, the northeast, for example, has substantial transmission constraints, and so they're very challenged. And they're actually importing natural gas via ship into their control area to meet the needs of their generation and their residential requirements.

And so, there are situations where people are much more challenged than we are from an infrastructure stand point, but there are other aspects and I'll also go into that.

From the FERC stand point, they felt it was a very high priority. There’s a quote in there that you can read, from Commissioner Moeller. And they were very committed to structuring a process where they could get people involved, bring people to the table and find out exactly what those challenges where, and what is being done to overcome those.

And while FERC is facilitating a lot of this, they’re also leaning primarily on a lot of the ISOs to provide information so they get a big picture of each area and what those challenges are.

So, to that extent, they had five regional technical conferences last year.

Our regional technical conference is the west, the Western U.S. The technical conference in D.C, in February of this year, involved information sharing. In particular, how entities are talking to each other from the gas and electric side, and various branches of the electric side with the local ISO, the responsible ISO.

And we participated in that conference. I was on a dialogue, and the discussion that I’ll get to in later slides, is primarily on information sharing. A lot of people are concerned about how you get a picture of what’s going on and how you proactively attempt to address that picture before it becomes an emergency. It’s essentially avoiding emergencies.

On April 25th, the technical conference was on the scheduling side. That was mainly related to how gas scheduling timelines work, and how the electric timelines are different, and trying to figure how to bring those timelines together. That was the start of that and there’s some relatively large gaps in how the timing works, and so they want to try to figure out how to coordinate those.

As an outcome of these meetings they are having quarterly staff reports on coordination activities that are essentially updates every quarter. And those started March 21st. And there’s some May 16th and 17th hearings in D.C. I’ll be attending those and presenting from the California ISO side related to a stats update on what we’re doing.

You’ll get it good just as I go into some further slides and see that we’re actually quite a bit ahead of the rest of the nation.

Okay, at a more regional level there’s involvement at WIEB, the Western Interstate Energy Board. There’s a working group underneath that, and I’ve got to get this right, it’s the Western Gas Electric Task Force.

And so, you have an initiative going on from this perspective. You also have a compliance initiative going on from WECC. And regionally, WECC and WIEB are pretty close in the states and so you have two perspectives. You have a liability perspective and kind of a proactive perspective on trying to figure out the best solution, rather than just from a compliance initiative that we’re seeing.

And so, I don’t have a slide on the WECC piece because it’s really just compliance. They’re collecting facts and attempting to comply with the FERC orders that are coming up.

From the WIEB standpoint, and the workgroup standpoint you have involved from the people in this room and so they do have visibility at this level into what is going on with the process. And I believe there’s an RFP being developed.

This is the piece that’s new to me, just so everybody knows. There’s an RFP being passed out, and I guess it was approved. I’m assuming. I’m assuming they have more information than I do and that’s moving forward.

In the California focus, in general, as I stated earlier, California is well ahead of the country in what we do.

Now, I do want to point out that I represent the California ISO and that's about three-quarters of the State of California. It's not a hundred percent.

And so, when I'm in meetings, and I'm at conferences, and I'm involved in communications, and I'm dealing with may data and market responsibilities, which does -- I'll talk about that in the second, I still don't represent a hundred percent of the State.

So, there are other entities that are responsible for coordinating other parts, like LADWP, and part of what's called "BANG" which is SMUD and the Western Sierra Nevada Region that bring other pieces of information together, and we have to collaborate as three entities as opposed to one whole for California.

Now, from the California ISO side, we share information pursuant to nondisclosure agreements. That's a big deal. We specifically wrote into our tariff the ability to communicate between the gas and electric sides. We got that approved and our parties do communicate. And as a result, we have a much better relationship when you have problems, when you have shortages coming up or maintenance done that restricts output, we actually have communication that occurs between the entities.

Generally, it does go through the ISO, as well, sometimes as direct communications we're posting.

The second bullet, sending daily estimated gas burn profiles to pipeline companies, that's actually what my group does on the data end. In California, we run a day-ahead market and we run a real-time market, and not many people know that.

And when we run a day-ahead market, we actually procure the bulk of the energy solution for the next day. In fact, more than 95 percent of it that's produced is procured a day in advance.

As a result, natural gas has a window to get procured outside of the spot market. So, these daily estimated gas burn profiles, we actually send those to the gas companies to show them, based on our awards what the burns are, what the burn rates are that they're going to see. So, the gas companies have advance notice to see if there are going to be impacts based on our forecasts for the next day.

Now, I want to be clear, those are based on forecast numbers so they're not a hundred percent accurate. But having 95 percent accuracy of something in advance is a tremendous benefit over relying strictly on the spot market.

COMMISSIONER MC ALLISTER: Can I ask you a quick question on that?

MR. BOUILLON: You bet.

COMMISSIONER MC ALLISTER: So, how -- what's a typical divergence between what you think it's going to be the day ahead and then the actual when it comes around? I mean, is it just a couple percent, a half a percent, or are there moments when it's more than that?

MR. BOUILLON: Now, is your question for the forecast or on the day that procurement as support of real-time? I'll talk about both --

COMMISSIONER MC ALLISTER: Yeah, I guess I mean both.

MR. BOUILLON: Okay. We're very heavily dependent on our forecasts. And our forecasts are based on weather, temperature, and a couple of other factors, and we use multiple forecasting agencies. And the forecast procures occur, essentially the forecast demand curve for the next day. And that curve is, obviously, never perfectly on, so you vary throughout hours of the day by a couple of percent.

Our goal there is to be around a two-percent deviation, 98 percent.

From a day-ahead solution standpoint, when I stepped into the day-ahead we were procuring about 95 percent of the real-time solution. Now, it's between 98 and 99 percent.

And while that may not seem like a big improvement, those -- once you get -- the closer you get to a hundred, the harder it gets to move numbers up to be accurate. And so, we rely very heavily on the weather forecast and that primarily explains the deviation.

But being around 98 percent gives us a good price stability as the economic side, but it gives a very good reliability number for the gas companies to work from, or around 98 percent on the day-ahead solution.

Let’s see, quarterly meetings to discuss outage impacts. Now, on my outage side we actually go and we do regional outreach meetings to discuss outages. And outages are a big deal because they impact gas output. Because depending on what the outage is, it could be a generator outage that’s one of our more efficient gas-fired units and it’s on a long-term outage, and we’re dealing with that and trying to schedule around it.

And, obviously, if you take a very efficient unit out, it takes more gas to get the same megawatts to produce the electricity.

And then, we also have, if you have gas line maintenance work that restricts the flow, then we have to work around that. And we have quarterly meetings that address what we're aware of in the groups.

Now, the point that's important in that note is that in those meeting we invite the other entities. So, you hear me talk about kind of the "BANG" which is SMUD in the Northern Sierra Nevada Region, and L.A. which is a big one.

In the southern meeting that we just had, we invite L.A. So, we get participation on the big picture when they're contributing. We're not just saying, oh, we're the ISO and we're only doing a Swiss cheese and we're going to leave some holes, we're trying to get the whole picture.

The goal is reliability and in these instances here we're shooting for reliability. We want to make sure everybody has as much information that we can provide, and we collect as much information as possible to get that whole picture.

This was actually excerpts from the FERC report that was issued November 12th. And the quotes, the reason I put those up there is to say that California's in pretty good shape. There are multiple instances where we're doing things that the rest of the nation actually is complaining that they can't do. And that's primarily the communication exchange between entities.

And so, if you looked at references to that, and the non-disclosure agreement, as well as communication we, luckily, had vision back when we were setting up the tariff in this area to say it’s important that people talk.

Because while people look at the ISO and talk about prices, market prices, the main function of the ISO is reliability. It’s reliability through markets. And we want to make sure that we have that reliability piece nailed because nobody wants blackouts.

And so, when you look at the reliability focus, these are great steps that we’ve taken and have actually played out to be under the scrutiny of what FERC is currently doing, very beneficial to our outputs.

The last thing I wanted to say, the final observation is that this is changing. It’s an ongoing process. As more information becomes available, you know, everybody is growing.

Now, while we may be ahead of the pack at this point in time, that doesn’t mean we sit, stop, celebrate and, you know, watch everybody else work. We actually are focused on what can we do next? What can improve better? How can we work and coordinate with other entities better?

And this has a lot to do with looking at the bigger picture. And that’s why when you look at the regional pieces, and I started at FERC, and then I went to the Western Area and then to California.

Looking at what we want to do from an ongoing process, we actually want to take California and start pushing that out so you end up with consistent approaches and methodologies that are essentially best in class. Some of which may be ours, some of which may not be ours, but the goal here is to have a best-in-class approach.

And, finally, the focus is on future system changes. And there's a lot of discussions in this workshop about addressing, from the gas side, changes.

And there are lots of other system changes going on in the future, different renewable sources, different transmission modeling, different generation solutions.

Different generation solutions will be a challenge coming up with on multiple fronts, especially on the natural gas side, and addressing those proactively and making sure that we have the necessary infrastructures that will be very critical to that success.

I believe that is it. Yes, it is. Are there any questions?

Unfortunately, I have another meeting obligation so I'll be leaving at lunch. And I know there's an open forum before lunch and I'll be here for that. But if you think of anything in the afternoon, or you have written questions, you can just e-mail me and I'll respond to them, okay.

MR. RHYNE: I wanted to ask if you'd address one question. So, have any of the gas utility companies expressed concern or has the discussion revolved at all around kind of the growing role in renewables in California and how has that affected your role in terms of connecting the gas and electric side?

MR. BOUILLON: That's a good question. I was contemplating whether or not we wanted to put in the renewables piece. This discussion was focused on gas/electric coordination, so we were looking at kind of like where we are, what we're facing.

And the focus on future system challenges, renewables are an interesting paradigm because they're, at least with current technology and, you know, most people think solar, you think of what's on top of a house.

But if you look at on the high desert, there are really, really large solar installations that use different technology than just the photovoltaics that are on top of a house.

And they provide different energy paths. So, solar, when it gets cloudy, you see shifts in the output. Wind, when the wind starts and the wind stops you see, in the output, the changes in the output.

And from a natural gas standpoint, that variability can be very challenging if you’re trying to use natural gas-fired generation to backstop those renewables.

And that gets into the spot market solution, which is what I was talking about, the forward procurement versus the real-time or spot market procurement.

Yes, they are concerned about that. That’s a big issue for storage and I don’t know if that’s on the agenda. I think it is, right, because it’s -- but storage is one of the best ways that you can help support the intermittent nature of the renewables is by having sufficient line packing or sufficient storage packing, I don’t want to get into too many details on that, where they do have sufficient reserves for spot market support for the gas-fired generation to backstop some of the renewable variability.

Right now, we’re doing it today, so I want you to know that’s not an alarm sound or anything. It’s being done today. We have about 5,000 megawatts of wind in California that’s -- we’ve got more than that installed, but actually -- the peak we've seen for wind in California, right now, is about 5,000 megawatts. For solar, it's just under 2,000 megawatts so, about 7,000 megawatts for those two sources right now.

Obviously, we have tons being installed so it's continuing to grow. And we actually had, I believe, nine solar peaks in the last 14 days. So, you see it coming online and you see those megawatts starting to decline on that variability.

COMMISSIONER MC ALLISTER: So, what would just be a vision of a future scenario, when we'll have -- I think it's PG&E and SoCalGas is going to talk about the storage issue.

But I guess, from the ISO's perspective, there's sort of the natural gas equivalent of energy versus capacity and, you know, on the electric side.

So, you know, it could be that much of the -- it could be that much of the natural gas that's needed is utilized in an increasingly short period, sort of at those morning and afternoon, and particularly afternoon ramps.

So, I guess, is that likely to push you over more to the spot market or do you see -- do you not really see that risk?

And what, I guess if you could give us a sense of what the difference between, you know, a day-ahead procurement and a spot market typically looks like that would be nice, just in terms of the multiplier.

MR. BOUILLON: Okay, you -- I'll ask you a question on that at the end because I need some clarification.

The question about integration of renewables and the possibility of like a gas-fired generation on the load pulls, the morning and evening load pulls, this comes back to forecasting because if we actually have the forecasting, you can actually pull a lot of this into the forward market, into the day-ahead market.

And we currently have wind, quite a bit of wind and some of the solar scheduling in the day-ahead. It's actually our data and the accounting for variability in many cases. Not all of it. And, again, it's new so it's not a perfect solution, but if you look at what we've done just in the last three years with the wind, we've seen tremendous improvements in the wind forecasting.

So, as we mature in the information, and it's hard because you can't so, oh, there's a lot of wind in North Texas so, therefore, we can follow their models. Because California's weather patterns aren't the same as Texas, you have to establish, and then build, and mature your own models, and that's what we're in the process of doing now.

And the better you get on the forecasting, the better you get on understanding the weather patterns, the better you'll be able to push that into the forward market, into the day-ahead market which will get you out of the spot need for that provider stability.

And that's our ultimate objective.

And solar is a little harder predict because, obviously, in wind we can determine at different evaluations wind flows and that will tell us the patterns.

And solar, and I'm not professing to be a renewables expert, I just use that data for day-ahead.

In solar, you know, cloud cover's very difficult to predict whether you're getting a cloud cover.

Your last question, I believe, was related to the fact of the --

COMMISSIONER MC ALLISTER: So, yeah, the -- well, no, no, I meant like price. So, you know, if you're off by 15 minutes on a heavy ramp you're going to -- that may -- I guess I'm asking the question, does that push some of your procurement over to the spot market? Is it more likely to do that than sort of the way we are today where, presumably, your curve's a little bit flatter?

And then on the price, you know, what's the typical difference between -- what's the price downside of pushing more energy over onto the spot market?

MR. BOUILLON: Now, gas side or electric side because I --

COMMISSIONER MC ALLISTER: Yeah, I'm thinking gas side.

MR. BOUILLON: Okay. I'm not an expert on the gas market on prices. I know spot is more expensive than the longer-term procurement. I don't know the factor, like 30 percent or 40 percent.

On the electric side I can speak a little more, though that wasn't your question. And that is, typically, generation reflects the fuel price. So, if you have a lot higher fuel price in real-time, your bid is going to be higher, so that the clearing price would be higher.

So, I can extrapolate that to say, in general, it's maybe 15 to 20 percent that I see. That I see. Now, they may be eating some of it and it may be more. But from what I see between day-ahead and real-time prices, you know, it's about 15 percent on the difference. It varies, but about 15 percent that I see.

Thank you.

MR. RHYNE: All right, thank you, Brad. Are there any other questions in the room?

Any questions online and on the chat?

No. Okay, once again seeing none that actually turns into a nice segue for our next presenter.

Roger Graham from Pacific Gas & Electric is joining us here today to talk about the role of storage and their thinking in their operational system.

So, Roger, I think the floor is yours.

MR. GRAHAM: Thank you very much. I'll talk a little bit of gas storage.

How do I get this thing to move? Ah, there we go.

I think the SoCalGas, in his presentation we'll maybe talk a little bit more about how the physical storage fields work. This is a representation of McDonald Island, PG&E's largest storage facility. And you can kind of see that it goes down to the gas reservoir. It's approximately a mile deep for our storage fields.

There's lots of well bores, lots of wells that have been developed into the field.

This is a schematic of one of our platforms of how we get the gas out. The little red spikes there are all the different wells and each one of them are individually controlled to ensure that you can maximize the amount of gas that's flowing out of the facility at any given time.

A typical reservoir is not really that uniform, so each well tends to perform differently, so it's important to have those types of controls.

In Northern California we're blessed with an abundance of gas storage assets. PG&E has three dedicated fields, McDonald Island, Los Medanos and Pleasant Creek. And we're a partial owner in a fourth field, Gill Ranch.

Together, that adds about 105 Bcf of working gas. We can inject about -- at the lower field pressures we can inject about 635 million cubic feet a day.

And we can withdraw over 2 Bcf and that's, I think, is really important and interesting for our ability to balance the system and to make a lot of equity in the market is our ability to withdraw very large quantities of gas into our system.

In Northern California we also have four independent storage providers, Wild Goose, Lodi, Gill Ranch and Central Valley.

Their combined working gas is just about the same as PG&E's, about 105 Bcf. They have a little bit more withdrawal -- I mean, injection capacity than PG&E, a bit more, and they have quite a bit of withdrawal capacity as well.

Well, PG&E, we use gas storage for three basic functions. The first one is to meet our utility obligation to serve all customers regardless of the weather conditions, regardless of how fast they want to use the gas, no matter what time of day they use the gas. We use our pipeline system and our storage to meet those obligations to ensure that every customer has gas when they want it.

The second major function is providing system balancing, and that is matching the amount of supplies that come into the system any given day or any given moment to the amount of gas that's going out of the system.

And also, there's imbalances between the operating pipelines, as well as the amount of gas that's consumed for shrinkage, which is either metering errors, gas consumed for compressor fuels, and various things. But measuring shrinkage every day is a very imprecise science. So, the differences in shrinkage any given day, over a given period end up in the storage fields or out of the storage fields if you're under.

And the last basic function is to provide market liquidity and seasonal price arbitrage. I mean this is -- I think a lot of people have always thought of gas storage as being, it's just the ability to buy gas when it's cheaper in the summer months, or the spring and fall, store it and bring it out in the winter.

There is a lot of that and that's the major -- one of the major things. But it also does a lot for liquidity in the market, the ability to make very short-term transactions. You know, if you have a little bit too much supply today and you don't know what to do with it, you can put in storage. If you're a little bit short, you can take it out of storage. And it really allows the market to be very liquid on a peak day.

So, I'll go a little bit into each one of these areas. The utility obligation to serve, I'll give you an idea of the amount of resources in the PG&E system relative to some of the average days, cold days, or what we call abnormal peak day.

On the supply side, you know, you look at these and PG&E has three Bcf or pipelines coming into the system, but on a planning basis you might really consider only maybe two Bcf is available because we know a lot of the upstream markets from California when it's cold, or on a hot day consume a lot more gas as well. So, you can't necessarily assume that there's going to be three Bcf of flowing supplies into the system.

But if you take a fairly conservative assumption that two-thirds of it would be available, which our historical pattern has been actually much better than that, and then you look at storage, while we have quite a bit more than 3,800 of withdraw capability. Storage fields, their ability to withdraw gas into the system drives with the amount of inventory in the field.

So, most of those capacity numbers you see on the previous page were at full field, so you take about an 80 percent discount for that number, assuming that the storage fields won't be completely full.

Some field are more efficient at this than others, but for this presentation I used an 80 percent reduction in that capacity to represent that the fields aren't always full.

So, that's -- you know, 5.8 Bcf as supplied is really easy to obtain. I mean, it's very available. You're not really depending on, you know, the pipelines being full every day. You're not depending on full storage withdrawals at any moment.

When you compare that to an average winter day at peak you need about 3.4 Bcf. A very cold day just recently occurred, January 14th, was actually peaking as the second highest send-out day that we've had in the history of our utility, at 4.2 Bcf. So, that did represent, you know, a fairly extreme example for us that day.

And then we had, in our planning criteria we call that abnormal peak day, which is about the coldest -- representing our demand in what would have been the coldest day in the last 90 years. And we think that the demand would be around 4.8 Bcf.

So, you see we still have quite a margin of safety for being able to supply the demand in California -- or Northern California.

In there we used -- this is a little bit about how we use our storage fields for system balancing. Again, it’s not just matching daily intakes, but hourly intakes. Within the day you see quite a variation in our send-out. Especially in the winter, with residential customers, we all have the same habit. We turn our heaters off at night in California, for the most part, and then we have a nice programmable thermostat, well, hopefully everybody does, it’s a good energy conservation move, and they all kick on at six o’clock in the morning, or thereabouts, maybe a little earlier, and we see a tremendous uprush of gas in the system to serve that demand.

In fact, that type of peak is much larger than any type of peak we see from electric generation. So, you use a lot of gas storage in that.

Going back to that day in January, the 24th, I think our average storage for the day was somewhere around 800 million point 8 Bcf on a -- in a peak hour we got to over 1.1 Bcf for storage withdrawals. But that's the type of variation you see within the day. So, gas storage does a lot to deal with that.

Then matching supply, over the entire day and then matching the supply and demand over the month.

For PG&E, we just require our customers to balance their supply and demand monthly, except for the days we call operational flowers. But for most of the part, most of the time customers just have to match the amount of gas they bring into the system with how much they burn over the month.

And, you know, those day-to-day fluctuations get put into storage.

On the right side of this chart is an example. We used both our pipeline inventory swing, which is the upper part of the graph, and our storage and catching withdrawal capabilities to balance that.

We do see at times where we do -- we have dedicated at least 75 million a day in catch and withdrawal for system load balancing.

On any given day we do use more than that. PG&E does use up to the full capabilities of the system to balance if it's needed. So, we don't just limit, say, our 75 a day for load balancing. If the system needs more gas to come out of storage in order to make the system work, we will do that.

In fact, we've seen catch and withdrawal rates go well over 200 million a day in a given day.

That's just for load balancing, that's not gas scheduled out of the fields for, say, our procurement prove, or for our customers who've scheduled the gas. That's just withdrawals that we make in order to balance the system.

And the last part I'll talk about is market liquidity. PG&E Citygate is actually a pretty liquid market. I'll just give you one example, there was over -- there was quite a bit of gas period -- I've seen since that that was actually quite a low day for PG&E's liquidity. It usually averages over a Bcf of gas traded every day, even with Citygate. You know, and that's a combination of flowing supplies, a combination of PG&E storage activity, and the activity of the independent storage providers and their customers. So, there's quite a robust market there to be using the Citygate.

COMMISSIONER MC ALLISTER: Could I jump in?

MR. GRAHAM: Okay.

COMMISSIONER MC ALLISTER: So, I'm curious about this, sort of the -- you're talking specifically about storage here, so maybe the overall system is a little bit different.

But I guess I'm -- it sounded like you were saying that the extraction of storage for generation from -- like the generation causing extraction from storage on, say, a peak summer day where everybody's cranking up their AC and, you know, presumably, you've got a bunch of gas-fired power plants needing gas is less than the -- that caused by retail demand for heat on a cooling -- I mean on a heating day in the middle of winter, say. Is that --

MR. GRAHAM: That's correct. The winter day's substantially larger than the summer day.

COMMISSIONER MC ALLISTER: So, that's an interesting data point because I guess there's been some talk about sort of the electric sector. There's been a lot of talk, actually, that the electric sector's impact on, you know, the need to match localized storage with -- in this future where we're needing to ramp, and scale up, and scale down quickly as renewables come and go, and the concern meaning that that would cause some -- potentially, some localized problems on the supply side for gas to those power plants.

Is that sort of not as big an issue, then, or sort of what's the dynamic there? And, you know, we can talk about the whole system and not just the storage component.

MR. GRAHAM: For PG&E, it doesn't seem to be a big issue.

COMMISSIONER MC ALLISTER: Uh-hum.

MR. GRAHAM: PG&E's a somewhat unique utility. Actually, PG&E's, two of the large gas utilities are actually quite unique in the size of our assets. You can go to the rest of the country and you don't see gas utilities that represent as big a service territory and have as many of the assets as we do.

As a result of that, we have served very large residential loads, you know, through our system, and we've designed our system to meet those peak hourly needs. You know, because that's the way we grew up doing it.

You know, in the east it's very different and a lot of the residential market's not even on natural gas. There's still a lot of fuel oil being burned and things like that. And a lot of the power plants are served directly from interstate pipelines.

And they have a very different operating characteristic than serving a lone distribution company, like PG&E.

COMMISSIONER MC ALLISTER: Interesting. So, we can have the big trucks on -- you know, we have the 18-wheelers on the road with Smart Cars, or bicycles, even. So, we’ve got to get one -- just to use that analogy, we’ve got lots of different tracking on that and they don’t really have that issue as much, so we have to look at that here in the State.

I guess I’m wondering if you think it’s the same around the State? And we’ll hear from SoCalGas a little bit later. And maybe Edison would have something different to say about this.

But the local liability, capacity, and security is really -- you know, obviously, has to be foremost on our minds. And so, I’m kind of interested in seeing how that matches up across the State. And I know that Ivin and his team are looking at that, too.

MR. GRAHAM: Yeah, PG&E’s also pretty blessed in that most of the storage fields, at least the ones that PG&E owns are located very close to the major load center.

But PG&E also has a lot of transmission ability, through its transmission system, to move that storage throughout our service territory. We don’t have a lot of pipeline constraints.

COMMISSIONER MC ALLISTER: Okay, thanks.

MR. GRAHAM: So, talking about market liquidity, on a set-down basis when you look at the load shape of our end-use customers, we're definitely a winter peaking pipeline. That is, there's a lot more gas consumed in California in the winter, than in the summer.

But if you looked at our flows on our backbone system, it peaks in October and then again in April and May. And this is the result of gas storage. You know, those are the cheapest months to buy gas, usually, in an annual cycle.

Yeah, you see much higher flows on our backbone system to satisfy the injection requirements into the storage fields. And then you actually see a dip in backbone flows in the winter.

You know, even though that's our highest usage day, you're seeing less gas coming into the State in the winter, but the demand being satisfied from storage withdrawals.

And, you know, a lot of pipeline. I think, possibly, we've decided, well, would we have enough storage to actually flatten that curve, right. And for most utilities that would be, you know, ideal.

We've actually, with the amount of storage built in Northern California, we've gone beyond that to more than flatten the curve to make us now, on our backbone system, a fall and spring peaking pipeline.

I mean, obviously, you notice there's a secondary dip, now. We do actually see a fair amount of storage withdrawals, actually physical withdrawals out of the storage fields in July and August to meet electric generation demands. So, we're now into a two-cycle storage season.

So, just in conclusion, there is ample storage in Northern California to meet the three basic functions that we build storage for and operate storage for, the utility obligation, system balancing, and market liquidity.

Are there any questions?

MR. RHYNE: Yeah, I was wondering if you would mind addressing just one issue. You mentioned, you showed a slide that talked about core and non-core, and you didn't explain those terms, necessarily.

And I think what would be interesting to know is withdrawal of storage to meet peak demand under, for example say a reduced capacity scenario, perhaps Redwood or Baja, or something has happened upstream.

As you withdraw from storage to supply those customers and maintain reliability kind of who falls into those categories of core and non-core and, you know, where does electric generation kind of fall in there.

And then, is there some priority given to withdrawals of storage to kind of maintain the electric reliability, as well, in that kind of a scenario.

MR. GRAHAM: Okay. So, core is residential, small commercial customers. Non-core is everybody else so, essentially, large commercial customers, industrial customers and power plants.

So, we look on -- even on a cold winter day, at about 1.8 Bcf in demand coming from the non-core market, around a Bcf of that is electric generation and 800 is non-core.

On our system there's no real priority between core and non-core customers when it comes to storage withdrawals.

If there is constraints in our local system, you know, the lines that go out to Fresno, and Sacramento, and the various other parts of our system, if there's a constraint on there our residential customers have priority even over the electric generation.

And this is one of the things that we've spent a fair amount of time coordinating with, with the ISO, was understanding, you know, the need for various power plants and whether it involved -- a local curtailment happens and certain power plants are then curtailed what does that do to the electric reliability. So, we've provided that type of information to the ISO so that they know which power plants are at potential risk for curtailments.

Now, curtailments are a very rare item. You know, on the second highest send-out day that we've had, on January 14th, we had no curtailment. So, you know, it's got to get really cold. You know, it can get colder than it was on January 14th and it has.

But we don't expect much curtailment in the local system, so the power system seems to be pretty good.

Did I answer all your questions?

MR. RHYNE: I just had one additional storage-specific question. Does PG&E plan on adding any new storage in the next, say, three to five years?

And if so, what's driving that decision?

MR. GRAHAM: It's unlikely we'll add any storage in that timeframe. We have a lot of storage. The current market prices for storage, you know, sort of one of the main values of storage is that summer to winter price differential, and this has been substantially reduced in the last couple of years.

There is no longer, you know, a winter premium. At one time there were people, you know, who were always worried about supply availability in the winter and tended to bid up winter supplies, substantially over summer supplies.

But with the abundance of shale gas and the abundance of pipeline capacity, at least in the west, there doesn’t seem to be that type of concern. So, the forward curve is quite flat, now, and it doesn’t support development of a new storage project.

COMMISSIONER MC ALLISTER: One final question. You mentioned shrinkage and I wonder if you could detail that a little bit. You know, what are the sources of that, and the reasons for it, and what kind of percentage are we talking about, generally?

MR. GRAHAM: PG&E’s system, at the backbone level it’s about 20 percent, 22 percent. When you get down into the distribution system it can be around as high as three percent.

It’s a combination of everything that you really don’t know. One of the terms that’s in shrinkage is called lost and unaccounted for, which means you really just don’t exactly know what happened to it.

As you meter the gas coming into the system and you meter it going out, but all those gas metering, unfortunately, are not as accurate as electric metering. you know, you have a 42-inch pipeline with gas flowing through it, you know, you attempt really well to measure it, but there's lots of inaccuracies in that.

The gas going out of the system is measured at 5 million locations.

COMMISSIONER MC ALLISTER: Uh-hum.

MR. GRAHAM: And the residential gas meters are not a very sophisticated measurement device. So, in PG&E's system, anyway, they're not even -- they're not temperature correcting, so that the density of the gas that's going through the meter varies with temperature.

And on large meters we do correct for that, but on the small meters you don't.

COMMISSIONER MC ALLISTER: So, you know, in the electric system it's technical and non-technical losses, right. So, the technical are kind of what you can explain more or less, you know, temperature corrections and things like that. Non-technical would be theft.

So, I'm wondering what the equivalent is in the gas system. I mean, do you see non-technical losses? I mean, do you have teams going to track that sort of thing down, you know, like on the electric side?

MR. GRAHAM: Yeah, we have lots of non-technical losses.

The system, unfortunately, leaks. There is a fair amount of leaking in the system. Some of it we don’t -- a lot of it we know where it is. And in some of our remote stations we actually operate mechanical equipment, like valves, with gas pressure. We actually take a little bit of gas out of the system. Since it’s at, say, 800 pounds it actually can do quite a bit of work. But after it does that work it’s no longer 800 pounds and you can’t put it back in the pipe. You have to vent it.

So, I know that the gentleman who was earlier talking about the reporting requirements, that’s one of the things that everybody’s been trying to get their handle around with the GHG thing is sort of how much gas, how much methane is lost in the system, and actually escapes the system versus how much is lost and is really due to these metering inaccuracies, and that type of stuff.

We do have some theft in the system. We do have, you know, a group of people who go around and try to catch people. See, gas theft is actually a little bit -- generally, it is not as big as electric.

MR. RHYNE: Are there any other questions for this speaker?

All right. Okay, so we’re actually moving --

you can mark your calendars; this is a workshop that's moving very quickly, ahead of schedule in fact. We'll note that in the annuls of the IEPR history.

We have a speaker from Southern California Gas who -- we're trying to get him to log onto the system and he'll be presenting remotely.

I'm going to offer that we take, perhaps, maybe a ten-minute break. And if he hasn't logged on by the end of that, we'll move on to my next presentation and then we can open the floor to discussion and comments before, perhaps, we take an early lunch.

So, we may be out of here even earlier than we all expected and that will be good for everyone, I hope.

So, I will see everyone back in ten minutes, at 10:25. Thank you very much.

(Off the record at 10:14 a.m.)

(Resume at 10:28 a.m.)

MR. RHYNE: Okay, I'm going to ask everyone to start finding their seats again. So, thank you, ladies and gentlemen for bearing with us as we took a little bit of a health break and gave everybody an opportunity to stretch their legs.

Our next presenter is online and I believe we're able to get things started, if you can unmute him there. Manuel, can you hear me? Are you there? Manuel Rincon?

Did you unmute him? We'll try again.

MR. RINCON: Can you hear me, now?

MR. RHYNE: There you are. Thank you, sir.

MR. RINCON: All right.

MR. RHYNE: Okay, so you have presenter rights and the stage is yours, sir.

MR. RINCON: Okay, thank you. My name is Manuel Rincon. I'm with SoCalGas. I am an economist and I'm in charge of modeling the financial side of storage and risk management.

I'm presenting from pretty cloudy Southern California right now, so we'll get started.

So, can we go to the first slide, please? The next one.

MR. RHYNE: Okay, if you'll just click on your screen, you should have control of the slide deck.

Okay, I figured it out. Thank you.

Okay, so in Southern California we have four storage fields right now. We have Playa Del Rey, that's in Marina Del Rey in Los Angeles.

We have Aliso Canyon in the San Fernando Valley.

We have Honor Rancho. That's in L.A. County, the north part of it.

And, finally, we have La Goleta that's by Santa Barbara, that's south of UC Santa Barbara.

Now, even though we have four different storage fields in our system, gas control tries to maximize the storage capacity, as well as the injection and withdrawal capacity for the storage so that they, in fact, operate as just one giant field.

And that's exactly how we also sell our storage rights. So, customers don't have the right to one storage field, but just the storage right in our system.

Given that, at the moment our system wide capacity for inventory is 136.1 Bcf.

We have 850,000 MMCF of injection and 3,195 of withdrawal. That's injection and withdrawal per day.

So, this is a pretty simplified storage cycle and this is how the operation actually works.

So, if you go -- can you see my map at all, or you cannot?

MR. RHYNE: No, we cannot see it.

MR. RINCON: Okay, so on the top of the slide that will be the gas coming in from the pipeline or the distribution system. And that is coming at a pressure of about 250 to 1000 pounds per square inch.

And to inject that gas into the storage that gas has to be compressed to at least 1,500 pounds per square inch, but even up to 3,900. So, the gas has to go into a compressor and that process generates quite a bit of heat.

So, after that the gas has to be cooled down before it goes to the storage. That’s in order to not damage any of the equipment in the field. Obviously, that compression uses a little bit of fuel and we have a small charge, an in-time fuel charge for injecting the storage.

Now, once the gas is in storage it can flow out through its own pressure. However, when it comes out, it comes out with some liquid mixed in, so it first has to go into a separator. That removes the oil and water from the gas and the oil is then stored and sold into the market.

And, finally, the gas coming out of the ground comes out quite hot, again, so it has to go through a cooling process and then it goes back into the pipeline, which is once the gas is up on the slide.

So, that’s for operation.

Right now, this chart is showing for inventory throughout the year. The black line is a resource level during the storage season, which starts in April and ends in March.

You can see from the chart our system operates in two -- it has two cycles throughout the year. It has a pretty small cooling cycle and a much more substantial heating cycle.

The cooling cycle is during the hot months, so that would be usually August, beginning of September, and you can see the small withdrawal during that period. That’s pretty consistent year over year unless we have a pretty mild summer.

Then we have a much more substantial heating cycle and that means that the gas is withdrawn during the winter months which in our system, really is more December through March. In other systems it’s more November through March. In our system it truly is December, Jan., Feb., and only the beginning of March. We actually have some injections by the second part of March.

So, consistent with that you can see that our storage usually reaches or is near capacity right toward the peak of the summer and right before the peak of the winter.

So, another thing to notice is that even at the lowest point there is still storage. There is still gas left in the storage.

That function is usually insurance and that is insurance against any unexpected disruption in supply. For example, a hurricane in the Gulf Coast which could affect prices during the hurricane season, and even throughout the winter. Or even some disruption in the demand size. For example, a change in the generation, perhaps it is out of something else of that sort.

This chart shows more of the short-term cycles. So, the red line is showing the total receipts. That’s the gas that we would see from the interstate pipeline, as well as production in our system.

And then the black line is showing the system send out. It’s basically the burner feed demand. As you can see, the send out fluctuates quite a bit, where total receipts are elastic, which means that difference between the two lines have to be balanced through the use of storage.

What that does is that storage basically balances, so it’s for fluctuation between demand and that helps keep prices relatively stable. That is, storage also lowers the volatility of the market.

Also, moving a little bit toward the market, the fact that we have the storage also improves the liquidity of the market. So, when you have a very cold day, like the one that occurred in December -- or in January 2012, where you see that peak, that black peak, there is enough gas in the system or in the market to meet that jump in demand.

I’m going to go to the last slide and that is just the SoCal Border Forward Curve. And those are forward prices. We see how the market, basically, coordinates the injection of withdrawal periods. So, you can see that that mimics fairly well our inventories throughout the year so that we also have two peaks, two annual peaks, a small peak during the cooling season in August and a much larger peak during the winter.

These curves are (inaudible) -- they're pretty liquid, so they give a pretty good indication of what the market is thinking of doing or why the months are going to become injection and which months are going to become withdrawal periods.

So, that was a pretty short presentation. Hopefully, you have some questions.

MR. RHYNE: I actually think you may -- I do have a couple questions, if you could go back to the annual cycle slide.

MR. RINCON: Sure.

MR. RHYNE: So, my first question is one of interpretation. If you look at this slide, there are two peaks and two valleys, a relatively shallow valley there during the summer and then the far more pronounced one in the wintertime.

Would it be an appropriate interpretation to suggest that they show the relative importance of storage to, first, electric gen, which is shown by that shallow valley, and then residential and commercial heating which is the more pronounced one; is that an appropriate interpretation?

MR. RINCON: Yes, I think so. Once you incorporate whatever changes you have year over year on the number of cooling degree days and heating degree days that’s true. I think it’s a fair interpretation.

MR. RHYNE: Thank you. And then my next question is can you maybe speak to the relationship between the operation of your storage system and the operation of the electric system there in Southern California.

MR. RINCON: Can you please repeat that question?

MR. RHYNE: Can you speak to the relationship between the operation of the storage system that you operate and the electric generation system operated by Southern California Edison, specifically it’s gas-fired generation fleet? Is there any relationship there? How is that coordinated? And have you seen, perhaps, increased use of storage recently with a change in their operational profile due to the nuclear power plant outage?

MR. RINCON: Yeah, we don’t actually track that data so I cannot really answer that question.

Clearly, given the two cycles that we have, we do know that generators are using our storage to balance their supply and demand needs but I don't have any of that data. I really can't answer that question any better than this.

MR. RHYNE: Can you maybe speak a little more theoretically about the operation of your storage system in relationship to the increasing share of renewables in Southern California?

MR. RINCON: Well, I'm probably just going to say what I'm going to assume you already know, which is there is a lot of talk about the renewables being quite volatile so that the need for -- the importance of the storage is going to be greater as the demand of renewables increase.

That is because wind is pretty unpredictable. It can go up and down, and whatever changes there are in the generation are going to have to be met with gas generators and, obviously, the fluctuations in demand are probably going to be made up by storage.

MR. RHYNE: Okay. And then my last question, before I kind of open the floor to everyone else, you showed a map of the system with the location of your storage fields. Thank you. And just kind of to the untrained eye it looks like the majority of those storage fields are located sort of northeast of L.A. and kind of along the coast there.

Is there any constraint in the operation of your system that puts that storage of gas kind of out of reach of any particular region under an area of constrained -- you know, of supply constraint?

So, essentially, obviously it doesn't just magically appear where it needs to go the moment you withdraw it, it's got to be transferred there somehow. Do you deal with system constraints from those storage fields into the L.A. Basin at all and, if so kind of how do you work around those?

MR. RINCON: David Bisi is from Operations and he does the capacity planning. He's sitting right next to me and he's going to answer this question, so I'm going to pass the phone to him.

MR. BISI: Hi. If I understand the question, it was whether or not there are any -- I don't like to use the word "constraints", but any restrictions on getting storage to all corners of our service territory. And, obviously, there are.

I mean, people in San Diego do not have, or in the Imperial Valley, or on the far reaches of our systems do not actually receive the molecules from our storage facilities, it just doesn’t get there.

So, a lot of our services are done on a displacement type basis. A customer in San Diego may have purchased storage and may be using storage on a transactional basis, but in reality they’re receiving the majority of their gas from a plumbing supply along the southern system.

Specifically, you had asked about the L.A. Basin and that is not one of the areas that does not direct access storage. All four of our storage facilities can serve customer demand in the Los Angeles Basin.

MR. RHYNE: So, maybe I can expand on that. You mentioned San Diego. So, is San Diego Gas & Electric, their service territory and their generation resources, would they kind of view the use of your storage perhaps differently than, say, Southern California Edison who’s kind of co-located there on top of your storage fields?

MR. BISI: No, I don’t believe so.

MR. RHYNE: So, it’s -- I’m sorry, so functionally you would say that it’s essentially just as accessible to San Diego, as it is to L.A. even if it’s not directly the same molecules reaching them.

MR. BISI: Correct.

COMMISSIONER MC ALLISTER: Just curious, what’s the role of the Punta Azul Plant these days with respect to this -- the map here cuts off at the border, but then it's a facility that is interconnected here. I'm wondering, as far as supply goes, where that -- is significant gas being injected at this point south of the border?

MR. BISI: I'm sorry I don't know that I heard your complete question. It sounds like you cut off a little bit.

COMMISSIONER MC ALLISTER: Oh, I'm sorry. Is significant gas being supplied into the system or injected into the system from Ensenada at this point?

MR. BISI: You mean at our Ojai Mesa receive point?

COMMISSIONER MC ALLISTER: No, at the Costa Azul.

MR. BISI: What?

COMMISSIONER MC ALLISTER: At the Costa Azul gasification plant.

MR. RINCON: Oh, you mean, for LNG, is that the question?

COMMISSIONER MC ALLISTER: Yes, is there -- are there -- this is not directly related to storage here but is there -- what's the role of that plant in this system at the moment?

MR. BISI: It's just another source of supply.

COMMISSIONER MC ALLISTER: Right.

MR. BISI: And at the moment I’m not sure that the Costa Azul Plant is supplying customers in Mexico. I don’t believe we’re receiving LNG at the moment from Costa Azul.

COMMISSIONER MC ALLISTER: Okay, thanks. So, I wanted to --

MR. RINCON: That seems to be market based and the gas just goes where the best price is. So, it’s supplied when we need it and if we don’t need it, or if Mexico doesn’t need it, then it’s just not there. It goes to Japan or wherever.

COMMISSIONER MC ALLISTER: Well, I guess I’m trying to get -- so, I guess I want to follow up on Ivin’s question about, you know, are there any local constraints in, say, the San Diego Region just generally.

So, if you did have a -- on that cold winter day, which doesn’t actually happen in San Diego that often, I’d say, living there myself, but on that peak day, whether it’s in the summer where you need more power or the winter when you need -- you know, have some anticipated heating load are there any capacity constraints to getting gas workings to go and do you anticipate any on the horizon if -- if, for example, you have more generation needs?

MR. BISI: See, my opinion is when we talked about constraints, constraints are one of the system designs. The system is performing perfectly as it's designed. It has enough capacity to meet my customers' firm demand on that system.

I have enough supply sources to meet their -- the demand on my system, as well.

Whether customers are utilizing those supply sources or whether or not there's more demand on the system as an interlockable component is sort of beyond the whole planning horizon here.

I can build my system to do whatever we want it to do, whatever the market wanted to do, but it's one of costs. So, right now my answer would be no, there are no constraints on my system at any point. It's functioning and performing as it was designed.

COMMISSIONER MC ALLISTER: So, going forward you really just depend on knowing what the scenarios are that you're planning for. If I'm understanding your answer, going forward you would just basically say, okay, what are we designing for and you design the system and then you'd build it to meet that demand.

I mean, I think in theory, you know, obviously, I think that's the way it works. I guess we're kind of struggling with what the reality is going to be 5, 10, 15 years from now and trying to see if there are any issues on the horizon, and so that was the words from my question. And if you have any insight on that, that would be good.

MR. BISI: Yeah, that's a fair question and we do forecasts. We do a 30-year forecast for our planning period. The forecast demand has not been increasing in California over that 30-year period, so we're not seeing that there are any problems that are popping up.

You all may be aware that there is, you know, a concern that supply is delivered to the southern system. The Blythe receive point is not one of the most economically attractive receive points for our shippers and customers, and so that is an issue. But that's not an issue that's going to be solved really without a large pipeline investment. And whether the market supports something like that is yet to be seen.

So, we're not seeing anything over the next 30 years that would cause us to be overly concerned. You know, an uninterruptible load could be interrupted, but that's the nature of the beast, right.

MR. RHYNE: So, I'd like to follow up on some information that was shared in an earlier presentation. The representative from California ISO, when talking about gas/electric coordination, mentioned the January 2011 cold snap in the Texas region that really restricted deliveries of gas to the Southern California Region.

Could you maybe speak to the role that your storage system played in helping to mitigate that and how significant was storage in supporting that event?

We know that there were no electric outages as a result, but my understanding is that the operational folks were getting a little nervous as the event went on, so maybe you could speak to the role storage played.

MR. BISI: Yeah, you know, I really don’t have that sort of knowledge on the individual, day-to-day basis. My department and my role is the long-term planning design of the system, and our gas control department works with the Energy Markets Group on the day-to-day.

But as I understand it, you know, storage would have been used to meet any supply shortfalls on our system. And on that particular day I know the major concern was getting enough supply on the systems so that it could be held up in conjunction with our storage supplies, as well.

MR. RHYNE: I’m sorry, what do you -- what do you mean by held up?

MR. BISI: Minimum operating pressures on our southern system.

MR. RHYNE: Ah, thank you.

MR. BISI: So, storage was put on withdrawal in the L.A. Basin and throughout the rest of our system to try to serve the demand in those areas so that the very little bit of supply that was being delivered at Blythe could be used to serve those southern system customers.

MR. RHYNE: And just a matter of curiosity and this is, again, more of an operational questions, obviously, molecules of gas are not instantaneous in transit. So, if you are -- if you see, say, a rapid spike in the San Diego Region how quickly does your gas system or can your gas system compensate for that, and what role does storage play in supporting that?

MR. BISI: The San Diego system is a little bit hard because the storage is very limited in getting into that part of our system. You're right, gas doesn't move instantaneously across our network so gas control has to respond to these increases, and they're continuously watching the system to see if demand is increasing on the system, or if supplies are having a problem getting into it.

Fortunately for us, you know, we don't have a lot of line pack on our system, but we do have some and that is used to meet these sudden ramp ups and changes in the hourly supply -- the hourly demand on our system so that we can get more gas onto it from our storage fields, or reconfigure valves and compressor stations to redirect the gas supply.

So, they use our line paths and our pipeline system to meet that hourly fluctuation.

MR. RHYNE: And just for the benefit of, perhaps, those on the room and those on the line, should we really be considering line pack as though it were kind of storage in place but, obviously, at a much lower capacity value than what you have in terms of your injection sites?

MR. BISI: No, for purposes of types of analysis like that, line packs on our system should not be used as a supply source to get through the day. First, we don’t know if we ever have that because you could be at minimum operating levels to start with.

And second of all, any line pack that you do use has to be replenished somewhere. At the end of the day, when we do our simulations of our transmission system, one of the criteria for calling it a successful simulation is we need to make sure our line pack is fully recovered over that period.

So, that should not be something that is ever assumed is available to meet customer demand.

MR. RHYNE: Okay, thank you. That's very helpful.

I'm going to open the floor to questions for this speaker or, actually, I should say pair of speakers, now.

Are there any questions here in the room?

Are there any questions online?

Okay, so we've kind of reached the point of the day, obviously a little early that we're going to open the floor to a more broad-based discussion. We have another topic area to discuss later in the afternoon with hydraulic fracturing, but we've covered a number of issues this morning. All of them I think are very interesting in terms of Cap and Trade, the gas and electric system interaction, and then we've had presentations on gas storage from both PG&E and Southern California Gas.

I was wondering if there were any insights, comments or questions on any of these topics from anyone here in the room or anyone online?

If you have a question on line, please, again, go ahead and enter it in the chat box and we'll make sure that the question gets asked.

We'll just ask the speakers to come to the podium there and speak to the microphone. Thank you.

MR. BRATHWAITE: I'm Leon Brathwaite. I work here at the Energy Commission.

I was wondering if the speaker from Cal-ISO could speak a little bit more to the issue of the maintenance of reliability as more renewables are integrated into the system?

We are looking at different profiles, obviously, in terms of generation, so I was wondering if we could have a little more clarity or a little more insight into that particular issue, which I believe is quite important.

MR. BOUILLON: Can I -- I need to fully understand your question, though. Are you asking about as more renewables come onto the system with different profiles, how -- what are we doing to ensure --

MR. BRATHWAITE: No, as renewables come on in general, whether it's wind or solar, whatever the profile is, how does that -- how reliability will be maintained as we move away from, say, gas generation to more, say, renewables or whichever generation these renewables will be replacing?

MR. BOUILLON: Well, I mean currently in California we're pretty lucky, we have a very diverse energy mix. And so --

MR. RHYNE: I think you need to speak into the mic.

MR. BOUILLON: I'm sorry, is that on? Let me speak closer to the mic there.

MR. BRATHWAITE: Yeah.

MR. BOUILLON: Sorry about that. In California we're a pretty diverse energy mix and so as you add more renewables into the mix, you still have a very diverse energy mix in place now, okay.

And so, whether you're adding more wind, let's say you're adding a new wind facility, we have existing wind in our mix already and that wind has been modeling. So, we actually have forecasting capability and we have historical information so that as the wind system because more known, you have better predictability, and so you have better reliability.

So, whenever you're installing a new one you have a learning curve and then that gets put into the bundle, and then quality and solution improves.

So, fortunately, these renewables are being integrated over time. They're not all being dumped in at one time.

And while it may seem different, I think is a good word, and it is a challenge, fortunately, it's being staged as it comes in. So, we learn, then we move on. We learn, then we move on.

But your question about like what does it mean to, say, a corresponding reduction in gas-fired generation? That's going to prove challenging because you need inertia in your system to match your changes in your demand. And wind and solar -- not all solar, because there is solar that has thermal generation in different technologies, but you still need to meet the inertia requirement to keep the power system adjustable.

And you're seeing changes in the gas technology, too. You see power plants being repowered on the gas side right now, where they're becoming more efficient, and they're becoming smaller units. They're getting higher output from -- excuse me, they're getting similar output from smaller units.

And so, repowering units, like there's been some done in the L.A. Basin, I believe -- I can't remember the name, but El Segundo, I believe, is repowering. So, you see those kinds of changes going into place.

And as those come online, you kind of balance it.

And I have -- I think the ISO has very high confidence that integration of renewables, while it may be challenging, I think it's something that actually we've learned a bit from and we're improving as we go along. And the forecasting is the key, of being able to understand the forecast of where that renewable is coming online and we're getting more and more information every day. And that helps us to put it in the mix and grow the information.

And a lot of the wind we have multiple years on, now, so we're getting really good forecasts in the day-ahead on that, much better than we had in our first year.

MR. BRATHWAITE: Thank you very much.

MR. BOUILLON: You're welcome.

MR. RHYNE: I was wondering if either of the representatives from PG&E or Southern California Gas could speak to another potential issue. There was -- the representative from PG&E mentioned, and I thought it was a very interesting point, that the morning heating ramp is actually many times larger than the ramp that's seen during peak electric generation in the summertime.

Is there -- has there been any discussion or analysis to estimate how large of an electric generation ramp would be necessary to stretch the system?

In other words, do we understand how fast and how big of a ramp would really kind of put us in the threshold of having to be concerned about it?

Because, obviously, you've got a system that's built for that winter ramp right now, both -- that winter ramp only grows as the population grows, whereas the generation ramp is growing as we install -- as we install renewables and then tie those renewables, in terms of their intermittency, to gas-fired generation.

So, do you have any thoughts, perhaps, on how large of a ramp we would be talking about before we reached that kind of zone of concern?

And the gentleman from PG&E's coming to the podium here.

MR. GRAHAM: We don't have a lot of analysis, yet. One of the things that is being worked on, somebody mentioned about an RFP being put out in the Western Area to look at some of this. And we will be getting a better understanding through that work, you know, sort of how big they think this can be.

You know, it's going to have to grow quite a bit from where it is today or it's going to have to be a lot more coincidental.

You know, we do have a very large ramp up in the early morning and if the gas-fired generation ramp was to be coincident with that, I think there potentially could be some concerns.

So, what we see today doesn't show that. I appreciate the fact that we do have some examples, you know, we do have some experience with it. Although, it's not the magnitude of where we think it's going to go, you know, there is a fair amount of solar generation in the system, there is a fair amount of wind generation.

And so, when we look at the impacts of what's existing has on our system, we're not seeing coincident ramp rates or coincident peaks that would be causing the concern.

MR. RHYNE: Thank you. Any comment from Southern California Gas?

MR. BISI: Well, I just would echo what the gentleman from PG&E said. You know, that is an area that is of concern now, the impact of the renewables, and we're looking into it but that work has only just begun.

MR. RHYNE: Okay, thank you very much.

Any other questions or points of discussion?

MR. MACLEAN: Chris Maclean, Energy Commission staff. The group that I work in does a fair amount of system production cost modeling of the electric side, using tools like PLEXOS, and we try to pay attention a lot to system operations, and sort of some of the things that come up, as well.

You know, when -- what is the frequency and how often is the electricity system stressed, so we see those in, you know, the various staged emergencies that get called at the ISO.

I’m wondering if any of this morning’s speakers have done much analysis into looking at the coincidence or correlation between emergency operations and type of conditions on the gas system, so that any time there’s OFOs are any of those related to times when we’ve seen electricity system peak, emergency operations? I’m just curious to see if there’s been any look at sort of the historical coincidence of that?

MR. BOUILLON: From the ISO’s perspective, the question, and I’m going to try to paraphrase and you can nod if I’m close.

From some of the flows on the gas side, have any of those contributed to an alert on the electric side, commensurate from what the ISO does when we issue the alerts? Is that the question, I think?

In general, the recent alerts in my memory have not been -- or there haven’t been gas flow restrictions that have contributed to that.

I’m only think back maybe, you know, a year and a half, you know, through last summer and back I haven’t seen one. So, I’m not aware.

There may have been a maintenance one in like

2010, in the fall, when there was some serious maintenance going on in the south system and we may have had a -- I'm not a hundred percent sure, but that would have been the last time I would have seen a correlation, potentially, okay.

But in general, like last summer when we were looking at them, there weren't any related to the flow restrictions on the gas side.

MR. RHYNE: All right, are there any other public questions or comments?

All right, we see none in the room. I'm going to ask if there's any questions or comments online. None. Okay.

Oh, we have one more here.

MS. ELDER: I'm Katie Elder with Aspen Environmental Group.

And my question's really for David and maybe SoCalGas. With the Kinder Morgan proposal to convert part of the El Paso line over to oil, what are you guys' thoughts at this point about impacts on your southern system?

MR. BISI: Well, you know, it all gets down to the supply forecasting at Blythe. And I don't have that information. I don't have that data available to me and I don't make those forecasts.

We have a Southern System minimum flowing requirement that's needed every day and if it's not there, the system operator will go out in the market and try to find the supplies.

So, I really don't have any sort of input, knowledge, opinion on what the Kinder Morgan conversion will do for us.

MR. RHYNE: Okay, any further questions?

All right, so we've reached a point where I thought we would be about 45 minutes from now, where we have a lunch hour.

Now, we would normally, given this timeframe, just give everyone a 90-minute lunch and perhaps come back a little bit early. But we do have a presenter this afternoon who's actually flying in and in order to keep with his schedule, we're actually going to ask that everyone return at one o'clock, so there's a two-hour break, and then we'll come back.

That way you can, perhaps, go further for lunch and there are quite a few very, very nice establishments around to enjoy, including our snack bar up on the second floor, if you're so inclined.

(Laughter)

MR. RHYNE: Sorry, I'm required to plug those kinds of things.

Thank you very much for your participation and we will reconvene at one o’clock.

(Off the record at 11:08 a.m.)

(Resume at 1:05 p.m.)

MR. RHYNE: We’re going to go ahead and get started with this afternoon’s festivities. And we’re going to have just a couple of quick housekeeping things.

We have a revised presentation from NRDC, which will be presented. And for those of you who picked up presentations this morning, a printed copy is now available on the entryway table. So, if you want a copy of that revised presentation, you can pick that up as well.

All of the presentations, by the way, will be posted online after the workshop, as well as a recording of the workshop and a transcript later, when it becomes available.

So, with that we’re going to go ahead and get started with the second half of our workshop which really helps us to shift gears a little bit from discussing the issues to discussing how are we going to characterize some of those issues inside of the model that we use to estimate natural gas market prices and quantities delivered.

I want to begin, though, with just a couple of short notes on the approach. First of all, we want to say up front that using a model is really not appropriate or even possible for all possible assumptions when we're dealing with all of the future variables involved.

As you probably heard, if you were listening in on the first half of the day, there's a lot of information, there's a lot of data that even the experts and the owners of the system in the field may not have their hands on.

And so, translating what's going to happen, not just today, but what's going to happen over the next 10, 15, 20, or even 25 or 30 years may just be impossible with regard to using a model.

Now, that doesn't mean that using a model is pointless. It just means that we may not be able to capture everything quite as distinctly, as accurately, or as crisply as many of us would like to see happen.

But what we are going to do is we're going to work to translate the assumptions or a set of assumptions into some numeric guidance, and we're going to use expert judgment and stakeholder input to do so.

Now, this is a little of the art and science of modeling, which is to say that in some cases, in order to make an estimate of the future stakes of the market, we actually have to begin with a guess about what that future state looks like.

And so, it’s important for us to population that world with information that comes -- that is the best information that we can gather, given the caveat that we are all human and none of us has foresight. I think if any of us did, we would have been playing the stock market and had no reason to be sitting in a workshop this afternoon.

So, given that assumption, we’re going to use this input, we’re going to use this feedback to try and do our best to put what is as much a consensus set of values together as we can, about what many of these future states might look like.

But the truth is, is that it’s impossible to predict a one path of the future, and so it’s often more informative to do analysis of what about a future that looks like this.

And so what we’ve done is built a few sets of scenarios, actually three groups of scenarios, and total about 10 scenarios of what the future might look like based on a number of assumptions.

And so, each of those groups of scenarios will be presented by a different staff member, members of our modeling team who have really been working very hard in the background not only to begin to build what these scenarios might look like, but to incorporate the information and the insight that we gain on a daily basis from interacting with stakeholders, with those in the industry, and those in government agencies.

And so, this is a first step, a kind of first draft of what these scenarios might look like. And we would like your help, first of all, in kind of turning those scenarios into a set of assumptions that we can use.

So, the three model scenario groups, the first is that we are going to present, again, the 2013 IEPR common case scenarios. Those were the reference, the high energy demand future and the low energy demand future which are coordinated across each of the divisions here, at the Energy Commission.

The second set of cases, the State and national gas uncertainty cases looks at a wide variety of possible futures that aren't really focused on shale, but on a number of other issues.

And, finally, the third set of scenarios, and we're going to talk through each of these in a moment, the third set of scenarios we're going to talk about are shale production uncertainty cases.

And because shale is such an important element in the domestic production of natural gas and it is a growing element in the domestic production of natural gas in the United States and, therefore, is important to California as a major user of natural gas, we felt it was important to really kind of look at what different futures might hold if shale develops along different pathways.

So, first of all, the 2013 IEPR common cases are coordinated input assumptions across all of the divisions in the Energy Commission that do forecasting for the 2013 IEPR.

This includes the Transportation Division. It includes the Electric Generation Unit, inside of the Electricity Analysis Office, as well as the Electricity Demand side and the Natural Gas team.

All of these allow us at the end, when we go forward into the IEPR, to look at a set of cases in one fuel type, for example transportation fuels, and be able to cross-reference that with a similar scenario, with a similarly-based scenario in any of the other fuels, whether that’s electricity or natural gas.

Now, there is a caveat here. These aren’t going to be run to the point where we have a perfectly converged, this-is-the-world-described-to-a-tee, but it’s certainly a consistent set of assumptions that work together.

Now, these three cases are a reference case, which represent kind of the industry consensus around what the future might look like for all of the different areas, including what future -- what future GP growth might look like, economic growth, population and demographics, all of those taken together.

We also look at California is very concerned with understanding and controlling, to some extent, how we grow our demand for energy. How our energy -- I should say our demand for energy grows as our State increases its population, as our State increases its level of wealth.

And so, we've done a number of things over the history of the Commission to look to deal with that. And so what we wanted to do is formulate a couple of cases that understand and that looked at what a different energy demand future could look like.

So, the first one, well, what if everything grouped to the point that the energy demand in California was very high?

And the third case, what if it were very low?

And so, these are a number of coordinated cases and Robert Kennedy, from our Natural Gas team will be presenting these cases.

Our second set of cases are State and national uncertainty cases. The first case here is to look at what if California, separate from the rest of the United States, really gets out and leads the nation, and gets ahead of the curve with regards to its policy implementation around natural gas and energy in general.

And so, there are a number of factors involved here. California has a long history of leading the nation with regard to policy and so we felt that this scenario was an important piece to look at.

The second one here is a natural gas/electric case. You may have heard a common theme this morning in terms of this -- this is a growing piece of how we understand how these markets and how these systems, the physical systems will interact.

And so, this is one that we're looking to model. What if we end up in a world where the natural gas and electricity system are even more tightly integrated or even more tightly interdependent on each other?

And, finally, we look at a case that has much lower innovation than we've seen or maybe assumed in some of the other cases?

Now, "innovation" is an important world here because it gets to the idea that as we get better at doing things we get more abundant gas, and we get it cheaper.

So, what if this rate of innovation slows? For example, we begin to run into roadblocks, the growth of innovation, the ability of innovation to reduce cost in the production of natural gas really kind of levels off or perhaps even stops?

And so, that's an important question because at some point we know that as technologies mature, that innovation rate does tend to slow down. So, this is another important case for us to look at.

Finally, the third set of cases -- I'm sorry, the State and national uncertainty cases will be presented by Peter Puglia from the Natural Gas office. Sorry, the State and national uncertainty cases.

The shale production uncertainty cases will be presented by Leon Brathwaite.

And these four cases, as we've given them kind of shorthand names here, hopefully, are descriptive enough to get a sense of we're looking at shale production, specifically.

So, what if shale continues in abundance out for the foreseeable future? That this land-of-milk-and-honey kind of scenario of everything just jumps out of the ground and keeps flowing, what if that continues on? And what does that mean for the natural gas market?

The next case we call shale reconsidered. And this one gets to the idea that policymakers, under some sets of circumstances, may look at the shale production areas and begin to consider some of them may be off limits, may raise the cost of production from existing shale cases through certain types of environmental regulations, and they shut down access to new shale cases? And so, we looked at what that means.

The third case here, is shale expensive? And this looks at the idea that perhaps, instead of shutting off access to these new plays, that the cost of extracting shale gas from the ground really is just raised by a non-trivial amount, and what does that mean for the natural gas market in the United States?

Finally, shale deferred. And this is kind of a little bit of a mix between the shale reconsidered and the shale expensive scenario, where we take our time and new plays that we know about don’t get developed and finished quite as quickly as perhaps they might under a more -- a more kind of upbeat scenario.

And so, we wait a little bit and they only come online later on.

So, those four scenarios will be presented by Leon Brathwaite.

So, we’re at the point now where we’re going to stop there because, obviously, I’m not ready to conclude the workshop, yet, perhaps to someone’s dismay. And we’re going to begin with Robert Kennedy, who will be presenting on the North American Gas Trade, NAMGas, updated IEPR common cases so, Robert.

MR. KENNEDY: Thank you, Ivin. Can everyone hear me okay? I’ve been known to speak a little bit softly up here.

My name’s Robert Kennedy. I work in the Natural Gas Unit here, at the Energy Commission, and I will be talking about the updated common cases, as described by Ivin.

And keep in mind these are used in the North American Market Gas Trade Model.

Before I start, I just want to say that I’m happy to hear your participation here. And as has been outlined throughout the course of this workshop, your input and collaboration is very much valued.

And throughout the course of my presentation, hopefully, you’ll see how this collaborative effort has been working, both within the Energy Commission and with both -- outside of the Energy Commission.

I will be taking about the updated common cases. And keep in mind I know Dave referred to it at the high energy demand in reference, and also at the low energy demand.

In my presentation and from my charts they're listed as low price, high price in reference. And I'll be making clarification as I go through my presentation.

But to start off, I just wanted to talk about some things that I won't be covering in my presentation. And these are things that were talked about in the February 19th, IEPR workshop.

And for those of you that participated in this workshop, this might be a good refresher just to kind of remind yourselves how this all got started.

For those of you that didn't, it will get you up to speed, you know, and kind of put everything I'm about to talk about into context.

And one of the presentations that was given was about the NAMGas Model, by Leon Brathwaite. And in that presentation we were introduced to the NAMGas model and we were taught how this was evolved from what's called the World Gas Trades Model.

And also, we were introduced to the original three common cases. All of the functions were listed in that presentation.

Also, my office manager, Ivin Rhyne, talked about the iterative modeling process. And we've been talking about this throughout this workshop. And I'm going to talk about this in more detail. Just keep in mind it involves our demand operatives, transportation, the electricity production cost model, and also our natural gas unit.

Finally, we did receive some comments from stakeholders from our February 19th IEPR workshop, and I'll be bringing some of these comments up and how they were addressed throughout my presentation.

So, this is a rough diagram of the iterative modeling process. And I'm just going to take my time and kind of walk you through this process right here.

And it starts off -- hopefully, you folks online can see my arrow moving around here.

It starts off with the Rice University Production, the Updated Economic/Demographic Assumptions.

And so, basically, this is information, like historical information coming from EIA demand for natural gas for power generation. You have historical Henry Hub prices for natural gas.

All of this information was put into an Excel sheet with the common metric equations were applied and future years of demand inputs were generated.

And this information was then input into our NAMGas model. And we did it -- this process was done just to get the ball rolling, just to kick off our model. And we were able to run the model and generate results, and these results were presented in our February 19th workshop.

Now, since that time, as I’ve mentioned, we’ve made some changes. We have some adjusted cases. And we have since generated new natural gas prices, which have been handed off to the Transportation Demand Model Group, and also our Demand Office.

So, they take those prices and, for example, for the Transportation Demand Group what we get -- they run their models with the information that we give them and from them we get demand for natural gas in the transportation sector. So, this is like heavy-duty vehicles, for example.

And this arrow, this one right here, that’s demand for transportation, for petroleum, electric vehicles that goes into our Demand Office.

And this arrow right here, going into our Production Cost Modeling Group, this is basically overall electricity demand. That information is given to our Production Cost Model.

And at this point, the model is run and what we get back into our model is natural gas demand for power generation.

And this last arrow, this big long one going around, this is natural gas demand in all the remaining sectors, which is commercial, residential, and industrial.

Okay, so we get all this information back from this iterative process and at this point what we do is, so we're replacing our original demand inputs and we're hard-wiring them to new demand information that we're getting from these other offices.

Now, the elasticity, the price of elasticity that we were using previously for the power generation in all states covered in the WECC, that's going to be turned off and all the demand numbers for power generation are going to be hard-wired into our NAMGas model.

Now, for natural gas demand in all other sectors, you know, commercial, residential, industrial, we'll be -- and transportation.

Now, outside of California the elasticity will be in effect in those states. So, this is how the process is going to work and this is where the majority of the remaining part of our work is going to occur is right here.

So, keep in mind that the work as far as setting up our main assumption, that has been mostly completed.

This is where a lot of the meat and potatoes is going to occur is right here.

So, I wanted to talk about changes made to our common cases. Let’s first talk about the reference case since our February 19th workshop.

And one of the changes were made in the coal-fired generation retirement. Originally, we had 30 gigawatts starting in 2014 for retirement. Now, we’ve since changed that to 61 gigawatts starting in 2014 and this is going to continue uniformly until 2025.

And this was done -- keep in mind that we did start with our model, our model from our last IEPR cycle and we did use information from the Brattle Group. But since that time the Brattle Group has come out with a new report, with new data that we’re now using, which is why we’ve made this change that you see here.

Next, we made a change in the Renewable Portfolio Standard and how that’s handled. Originally, we had California meeting its RPS on time, with a five-year delay for all other states outside of California.

We’ve since changed that so that California and the rest of the WECC states meet their RPS on time, and there’s a five-year delay elsewhere.

Now, we did this for a couple of reasons. There was a comment from SMUD, asking, you know, this doesn’t seem reasonable and we might consider changing this. And also, we made this change to make our assumptions more in line with the assumptions that's represented in the Electricity Production Cost Model.

Next, we have updated infrastructure capacity addition to export natural gas to Mexico. Some of you may know there's been a lot of activity to meet growing demand for natural gas in Mexico.

FERC has come out and said that several pipeline projects have been proposed and if all of them are built, they should be online by 2014, with a combined export capacity of 3.5 Bcf per day.

Next, we did adjust some of the structure in our LNG sector. And again, this is changes we've made coming from the World Gas Trade Model, restricting it to the NAMGas Model.

Previously, we had a whole world model, and we just felt that was too cumbersome. We wanted to focus on North America so all the links going to the rest of the world were basically combined into an androgynous link to account for LNG imports and exports.

And, originally, it wasn't working quite right. Some of the imports to North America were a little too high, so we had to make some adjustments there.

Okay, now, I want to talk about some changes made to the high price/low demand case. And, first, we'll talk about the cost environment. And I just want to say this is a major change. And I'll get more into this later on as to why we made this change, and some more details about this. But for now, just keep in mind that P50, we're talking about an average cost environment which is represented in our reference case.

And the P10 is a high cost environment.

So, basically, we went from an average cost environment to a high cost environment for the high price case and low demand case.

Next, you see the same changes, updated infrastructure capacity addition to export natural gas to Mexico and, also, the changes made in the LNG sector.

And just consider these are just universal changes made to all the cases. Keep in mind that our high price/low demand case and low price/high demand case, these are born from our reference case. There are some similar assumptions.

And all the assumptions specific to the high price/low demand and low price/high demand is outlined in the February 19th workshop.

Okay, now, talking about the low price/high demand case, we went from average cost of running to a low cost environment, which is the P90 line. And I'll talk about this in more detail later.

And for coal-fired generation we went from 1 gigawatt, starting in 2014, to 31 gigawatts retiring starting in 2014, and I explained the reason why we made that change.

And, again, we have our universal changes right here.

Okay, now, I just wanted to talk a little bit about the cost environment. I know this was covered in our last workshop, but I just wanted to kind of educate everyone to why we did what we did.

First of all, what you're looking at here is data graph from KLEMS, for capital labor energy manufacturing and service. And this is historical data that's in the graph.

And you can see that there's kind of a spike right here. This represents a high cost environment. In fact, the P10, the line that represents 90 percent change that production costs will fall below this level, the black line here represents an average normal cost environment. And those years are a typical cost environment, which is P50. And you can see that occurring in 1975, and 1986, and also in 2003.

And, finally, we have P90, which is the low cost environment, which is a 10 percent chance that costs will fall below this level.

Okay, now, I want to talk a little bit about the results that we got from these adjusted cases.

And this shows Henry Hub price results, a graph from 2011 to 2035. And the dotted -- the dashed lines that you see here, this is from our previous case results, as presented in our February 19th workshop.

And the solid lines are the new, adjusted case results.

And I should mention that we did receive comments from PG&E, saying that previously this band that wasn’t certainty, but was a range, was maybe not reasonable and doesn’t capture all of the certainty output that may occur in the future. So, we were advised to see about making it wider and larger.

And I can say the main thing that accomplishes was adjusting the cost environment, and I just explained that.

So, we did widen the zone just a little bit. And keep in mind that some may feel that this is kind of a narrow zone, and the reason for that is because we have an abundance of production coming from shale cases.

Okay, now, I want to talk about differentials, basically, looking at the price offered at Topock minus Henry Hub natural gas prices.

And you can see for the low case, when the bar is very much high that means Topock's very much higher than Henry Hub. And when it's down here, it's the opposite Henry Hub's higher than Topock.

Now, you can see in the formative years it's negative and then it becomes positive. And the main reason for that is the shale production -- natural gas production from the shale case is really ramping up as we move forward in the future, and this kind of re-orders the supply portfolio.

Okay, now, I want to talk about the reference case on a national level. And this is the snapshot of the year 2025. And there's no particular reason why we chose 2025. We felt that was just a good point to look out far enough in the future to see what's going on.

And if you look over here, you can see Canadian imports represented by the blue arrow. And keep in mind this is a gross number, is 12.7.

First of all, I should say that in the lower 48, demand is coming from two areas, and that's end-use and exports. And the Canadian imports is one source that the demand is being satisfied by.

Another is the lower 48 production, which is about 72.3. And also from LNG imports, which is fairly small at 0.21 Bcf per day.

Now, this export, this is the gross number as well, going to Mexico and also Canada, with a little bit of LNG, and that’s 8.4 Bcf per day.

Okay, now, we’re looking at the high price/low demand case, again for the year 2025.

And this parentheses right here symbolizes an almost 18 percent increased when you compare the price here versus the reference case.

So, all of these parentheses numbers are the comparison to the reference case.

And as you can see, the higher price did play a role in reducing end-use demand by 9.1 percent.

And when you have a higher price for natural gas it makes -- well, actually, I have to say for the high price case, the accepted assumption is such that LNG export explodes, so that’s why you see an almost 67 percent increase in exports.

And this demand satisfied by Canadian imports fell by 2.4 percent, the lower 48 1.2. And LNG imports rose by 204 percent because there’s such a high price being offered for natural gas. So, it’s just kind of a strange thing to happen when you see exports and imports increase, and that’s what happens when you force something in the market which, in this case, we forced LNG exports.

Okay, now, we're looking at the low price/high demand case. And when you look at the price compared to the reference case, it dropped by almost 14 percent.

And a low price has an impact on end use, driving up demand by about 10 percent. And export fell by 34.5 percent. And the reason for this is because there's more demand for natural gas, making less supply available for export.

And so, this demand was met by Canadian imports, which rose by 2.4. Domestic production picked up by 6.5 percent. And LNG imports declined by 57 percent, most of the demand coming domestic production increase.

Okay, now, I want to look at specifically how these case results affected California. And looking at the price offered at Topock and you can see, once again, our original case represented with the dashed lines.

And our new case is represented in the solid lines. And you can see, once again, we have achieved a larger zone of uncertainty.

So, here we show California where, again, the main demand is coming from end use. There's no demand for export in California.

And you see at the Malin Hub, 2.68 Bcf per day is coming in and this is the combination of GTN and Ruby. And we see 1.25 Bcf per day, and it also comes out to 2.32. Keep in mind this is our reference case for 2025.

Okay, now, I'll do a comparison against the reference case looking at our high price/low demand case, and price rose by about 16 percent.

And so, when you have the price rising, once again you see end-use demand dropping off about 8 percent.

And when you have demand dropping off, supply follows suit.

Imports at Malin dropped about 3 percent. At Rocky Mountain it's about 8 percent, Southwest about 12, and local production dropped off about 20 percent.

And this is our low price/high demand case compared against the reference case. And the price dropped by 11 and a half percent compared with the reference case.

And so, when you have low price it spurs demand, end-use demand, which picked up about 10 percent.

And here we have consistency with demand being satisfied at Malin, with a plus almost 4 percent. Rocky picking up about 5, the Southwest at 16 percent, and local production really ramping up at 45 percent.

So, in summary, these are the main things I want to leave you with. And the thing is, the work is ongoing. And as I've said in the past, our main key functions have been mostly set. However, most of the work is still going to be with the modeling iterative process, which is we're going to have new demand inputs as a result of the outputs from the Transportation Model demand and, also, the Electricity Production Cost Model.

Now, there's still a chance that we could receive some more stakeholder suggestions, so there could be some changes that result from that, as well.

And, finally, I'd like to remind everyone that we did address the, you know, concern with the narrow zone of uncertainty, and we did that by adjusting some of the cost environments, which did affect a slightly larger zone. But keep in mind it's still narrow because of all the supplies that we're getting from shale production.

Okay, with that I'll take any questions you may have.

MS. JONES: Melissa Jones with the Energy Commission staff. I have a question for either Robert or for Ivin.

I was looking at the coal-fired generation assumptions between the low and the high cases. I noticed in the reference case that you have much higher retirements starting at a much higher level, sooner.

And I was wondering about the rationale for that change in assumption?

MR. KENNEDY: Well, keep in mind that this is new information that we're dealing with. That old retirement number came from our previous model, the World Gas Trade Model which we used in the previous IEPR cycle. So, this is more real-time information and that's what we're using right now.

MR. RHYNE: Yes, that's what I was going to point out. The numbers, themselves, are the result of a survey conducted by the Brattle Group.

So, the previous survey had estimates of about 31 gigawatt hours and the more current shows about, I think the number is 61 gigawatt hours within -- with a range based on that.

So, that's the reference that we're using.

MS. JONES: My question's not about the overall numbers, it's about the rationale for lowering it in the low price/high demand case from what you have in the reference case.

MR. KENNEDY: It actually increased it from 1 gigawatt retiring to 31.

MR. RHYNE: Well, the reduction represents actually a reduction in demand, which will tend to lower prices along with it. So, it reduces the demand on the electric gen side for gas and reduces gas competition, helping to reduce the overall market price.

MR. RHYNE: All right, it looks like we have a question online.

The question is can we clarify regarding LNG exports in each of the three cases?

MR. KENNEDY: First of all, I just want to say that we did convert the World Gas Trade Model to the NAMGas model. So, previously, we had the whole world model with regard to LNG imports and exports.

So, when we changed it over to the NAMGas Model we disconnected the link to the rest of the world and we just have a single node representing LNG imports and exports.

Now, what was the question, again? Oh, okay, so originally when we looked at our results, the imports coming into the United States was very, very high. We knew it wasn't correct.

So, we went back and we looked into what the issue was and we found out that the forward cost trends were a little bit too high for the LNG node that we put in for NAMGas.

So, since that time we adjusted that number to correct that error.

MR. BRATHWAITE: I'm Leon Brathwaite. I work here at the Commission.

Okay, I suppose as considering the question that was just asked about LNG exports, in the high price case LNG exports were forced, okay.

In the reference and the low price case these are economic dispatched in the sense that the model decides what will flow and what will not flow.

But in the high price case, it was not an economic decision. It was forced because of the inputs that we put into the NAM, into the model. So, that was the only clarification I wanted to add to Robert's answer.

MR. RHYNE: Are there any other questions?

MS. VU: Hi, I'm Mia Vu from PG&E. I appreciate the effort that the Commission has done to widen the range of uncertainty.

But what I see here is the range of price uncertainty here tends to focus more on the cost side.

What we have learned from the past year, and a lot of discussions in the industry, is that there are changes in the demand side, as well.

Some are not immediate. For example, efforts to increase gas use in transportation, like the fleet vehicles, like CNG or LNG for large trucks and marine transportations. Those may not be immediate effect but, say, ten years down the road there will be some level.

Another that we saw is the -- what they call is a revival of competitiveness in the manufacturing industry. We don't see anything that competes, yet, but some examples of -- because our natural gas cost here, say, is about $4, while the world is paying, say $15, $16 in Asia, and then $11 or $12 in Europe. So, that brings a lot of competitiveness here.

So, I saw a lot of forecasts that shows there are higher demand, industrial demand longer term.

So, the question here, have you looked at those factors and may incorporate something in the model to show the wider range of demand, as well?

MR. RHYNE: Yeah, so first of all, thank you very much, that's a wonderful question.

The short answer is, yes, we have looked at that. At the same time, we're always open to specific suggestions, backed up with perhaps some references, on where we might find values for future demand for any of those values.

One of the areas that -- one of the things that we have done is we've looked at how demand might vary as economic growth nationwide really picks up.

One of the challenges in presenting the values that we have here is that we're presenting values for, really, what is a worldwide commodity, and in this sense largely a North American viewpoint on that commodity.

And so, fluctuations in that market tend to have to be rather large in order for them to show up as pervasions or changes in the price direction or the overall net -- or I should say, gross demand.

At the same time, we really would appreciate further input from PG&E, and anyone else who might have specific values that they think. We have, in fact, included natural gas transportation in these common case scenarios.

And our Transportation group is working closely with us to make sure that we have values that are grounded in reasonable assumptions, as well as understanding what growth might be in terms of manufacturing, and how all that comes into play.

The one caveat I would say is that you can only become so granule when you look at an entire North American model. And so we have to balance what data is available with the level of assumptions that we have.

MR. KENNEDY: I just want to add to that. And I just wanted to just remind everyone that the results that I'm presenting here are based on econometric historical data, and we have yet to fully go through the iterative process.

And some of these things that you mentioned are being considered in our other groups, our Demand Office, our Transportation, and also the Electricity Production Cost Model.

So, when they run their models and we get demand inputs back from them, it will help -- these numbers are going to be different after that.

MR. RHYNE: All right, are there any more questions in the room? Anymore online?

Okay, with that we're bring our next presenter, Peter Puglia, to the podium to talk about the scenarios addressing gas issues, uncertainty in the national and State uncertainty cases.

MR. PUGLIA: Thank you, Ivin.

I want to just take a minute to talk about the PG&E question about demand side effects on natural gas because that's principally my responsibility.

And I've mentioned three pretty ripe targets, mentioned LNG exports, mentioned industrial capitalization and increased demand in the industrial sector for natural gas and then, finally, mentioned natural gas vehicles.

Ivin's prep, we are looking at that, and that's more my job than anybody else's. And it's an important topic because it's in front of the Department of Energy right now, in their deliberations about whether to grant export, LNG export licenses to about 20 applicants who want to build terminals on the coastlines of the United States to export LNG.

And it's something that has to be modeled because the prices in the United States, while they might be $4 and $5, and they might be $20 in Japan and Korea, and $18 in Latin American and Europe -- actually, I think they're less in Europe, you still have the net back costs which, for getting LNG, for gas out of the United States to any of these other destinations, those costs could range between $4 and $6. That's Rice University, that's the publicly available numbers from them. So, that's going to add to your cost.

There are also -- whether LGN is actually going to get exported is also influenced by the proximity of overseas markets. China has, possible, shale deposits that are larger than the United States. Australia is currently the largest LNG producer in Asia and their costs to supply those markets are going to be less than the United States in any circumstance.

So, whether we're going to export anything to Asia is a big question.

Europe is probably going to be supplied by the Russians. They'll stop playing games with the gas problem and then they'll take care of that.

And the industrial sector has to be modeled on a global level and right now we're using a North American model to do that.

And if we model assumptions with industrial expansion globally, then we can probably get a picture of how to do that.

And we'd love to get some of your ideas about how we can do that.

We're also assuming natural gas vehicles assumptions that are a variety of different things, and those also treat demand side natural gas curves.

So, whatever you guys want to do to try to push the price or push other curves around, we'd really appreciate that, too.

So, that sounds like a fruitful venture and I would appreciate any collaboration we could get.

Okay, as Ivin mentioned, I'm here just to give you a quick recap of -- a recap? An introduction to the three cases that we constructed to attempt to address a marriage that we could possibly attain, that would pose certain challenges for the State of California.

Ivin described them all. The California policy case, which we discuss six assumptions that attempt to -- that are reasonable, could occur simultaneously, that attempt to treat the natural gas market's response in a quantitative manner.

We start out with -- each of them starts out with one of the core cases. In this case, the California policy case, it starts out with the low price/high demand common case assumptions.

Now, if it seems contradictory to you that you have low prices with high demand, you can just keep in mind that the supply curve moves out to the right, then all you need is for the demand curve to move out not quite as far and you'll get the low prices that you're looking for, and that's what we're trying to model here.

The assumptions that we change or add, or we use the P10 cost environment which, as Robert got into a little bit, that implies a 90 percent change of natural gas production costs fall below the line that you saw on the KLEMS chart, which delineates 160 percent of year 2000 benchmark costs.

Then, also, we assume that California meets its 33 percent RPS by 2020. And other states delay theirs by three years.

We also have very optimistic natural gas vehicle policy goals and energy efficiency is achieved, those goals are achieved by work of the Energy Commission's Energy Demand Forecast.

The last one, and Monterey Shale's fully developed in seven years. And this is on top of increased gas assessments for the Marcelus, Haines Whole Shale, and the Western Canadian Sedimentary Basin, which will help to satisfy a much higher supply than the demand and keep prices down.

The last of the six new assumptions, we're assuming that we'll have carbon credit price response curves because we're assuming a GHG cap and trade market, as you see at the bottom of the next section, along with the same low price/high demand common case assumptions that Robert talked about to some degree.

LNG exports, 40 cents per 1,000 cubic feet. Hydrofracking operation maintenance costs, 20 cents per 1,000 cubic feet. Additional costs for water use and disposal for conventional gas.

Coal-fired conversion, 31 gigawatts of coal plants convert to natural gas, or they're either repowered or replaced. Using the same technology improvement rate, 2 and a half percent, GDP is 2.1 percent.

And I already mentioned we do have a cap and trade market in that scenario.

The second, as Ivin mentioned, the natural gas/electric case. We're looking at a future where there will be greater integration of natural gas and electric system, and which is already happening, and how they interact with the future when they are more closely integrated.

In this case, we begin with the reference case assumptions. We add the P50 cost environment that natural gas and electric costs are either above or below 105 percent of year 2000 costs.

Instead of the reference case of 33 percent RPS by 2020, we replaced it with 40 percent RPS. We're jacking up the electricity's share, renewable share of the electricity market in sales.

And all of the WECC states will meet their RPS's on time.

We replaced the 61 gigawatt of coal-fired retirement in the reference case with 80 gigawatts. That's how that one works.

In that case, all the other variables remain the same as you see in the reference case.

Finally, it is below innovation case. Also, these haven't been populated, yet, we're just starting to do that.

This whole modeling, this will be modeling-impacted assumptions that will restrict U.S. gas supply. It doesn't mean the gas isn't still there, it just means that a different -- a number of different assumptions will prohibit it from being extracted from the ground. It's been there for a million years and we've had high prices a number of times.

We assume, however, the reference case P50 cost environment. But we assume a smaller North American recoverable natural gas reserves base, cut it down from 325 cubic feet of crude reserves by 7.5 to 12.5 percent.

And also, to limit spending on development of gas fields, we added in the 40 cents per thousand cubic foot, shale gas operations and maintenance charge, and 20 cents for conventional gas that we have the high price/low demand common case O&M assumptions.

And we cut the technology improvement rate to 0.5 percent.

And in that case we continue with the same assumptions as the reference case, as you see.

Are there any questions? Very good. Thank you.

MR. RHYNE: All right, thank you, Peter.

So, we've covered a number of different cases and I'm actually going to ask NRDC if they don't mind going a little bit out of order as we get to our next set of presentations.

So, we've covered a number of cases. First of all, the IEPR common cases and, really, for those kind of coordinated sets of assumptions and Peter’s really talked about three different scenarios that just look out into the future and ask what if. What if we have low innovation? What if California really pushes ahead of the curve in terms of innovation -- sorry, in terms of policy?

And, you know, this is all important, but as we get to kind of the crux of where the conversation is around natural gas, that typically brings us back around to shale. And I can’t tell you the last time I had a conversation about natural gas that didn’t at some point touch on shale gas development.

So, we’ve moved the discussion of this topic to being our last part of the day.

We have two presenters, one which, hopefully, is on his way from the airport now, and not breaking any speed laws by the way, and will be here shortly.

And so, we’re going to go out of order from your agenda just slightly. We have Miriam Rotkin-Ellman from Natural Resources Defense Council to talk about hydraulic fracturing and public health.

And then following her, hopefully very shortly, we’ll have Tim Kustic from California Department of Oil, Gas, and Geothermal Resources.

And so, with that I’ll turn it over to Miriam.

MS. ROTKIN-ELLMAN: Hello. Good afternoon. Wow, so I am so short, which means that I can’t see very many of you behind -- over the screen.

Yeah, that’s too bad. Otherwise, it’s just a voice behind a screen.

Thanks so much for having me. So, I’m Miriam Rotkin-Ellman. I’m a public health scientist with the Natural Resources Defense Council, NRDC. We’re an environmental advocacy organization.

And my guess is that you all probably are familiar with and work with many of my colleagues who work on energy policy in California.

I’m a public health scientist and my work primarily focuses on just the public health impact of environmental contaminants, whether that’s from industrial pollution, such as the case with hydraulic fracturing, or whether it’s associated with other types of industry activity.

So, what I’m going to do really quickly here is, figure out all the logistics, is talk about the rising concerns from the public health community about environmental exposures that could adversely impact public health. And for communities adjacent to oil and gas sites, and also for regional, and even global impacts from the increased use of hydraulic fracturing in oil and gas development.

And you'll see in my slides that there's a number of different terms that get used somewhat interchangeably. They all are somewhat indistinct, but for the purposes of this conversation you may see me use hydraulic fracturing, fracking, people talk about shale gas development, unconventional oil and gas development, natural gas development.

For now, just what I'm referring to is oil -- you know, oil and gas development in general. In this case we're talking about natural gas, specifically, that's using hydraulic fracturing as part of the development process.

The concerns coming from the public health community at this point range -- the Institute of Medicine, last April convened a two-day conference of experts talking about environmental exposures, occupational exposures, public health concern associated with the boom in natural gas development.

Other federal agencies, CDC, ATSDR, The National Institute for Occupational Safety and Health have all -- have initiatives, the Environmental Protection Agency, initiatives to both investigate, examine and express concerns about potential contamination issues that may adversely affect public health.

This is a quick overview slide and I'm going to speak to the air quality, and water, and soil contamination issues in more detail further in the talk. This is just an overview of the types of public health concerns including, you know, ranging from air quality, and water and soil contamination, which are your more typical environmental exposures, to some of the areas which are very important from a public health perspective, but don't often get discussed in the environmental sphere, noise and light pollution.

This often is from -- and public safety issues. Both of those reflect a industrialization of rural areas, in many cases, that go along with the boom in natural gas development associated with hydraulic fracturing, such that you have industrial activity often occurring in very proximate locations to people's homes.

Also, with an increase in truck traffic, traffic patterns, and the risks of traffic accidents, explosions, all of those are part of this sort of larger public health sphere when talking about this activity.

So, to talk more specifically about the sort of more typical environmental concerns, we'll start with air quality.

When I think about the air quality impacts associated with this natural gas development and processing I divide it up to looking at the local level, the regional level and the global level. The pollutants act in different ways, there is some overlap among them, but they -- in terms of thinking about the human side, they act in different geographic scales.

So, at the local level we're worried about diesel particulate matter, which has linked to respiratory and cardiovascular impacts, coming from large amounts of diesel trucks, construction equipment, drill rigs, pumps, et cetera, air toxics that are actually released both from the well, itself, and from the associated processing equipment.

Silica sand, which is used as a proppant in hydraulic fracturing process, it holds open the cracks. Silica exposure is a known, actually quite well-known occupational hazard in the mining industry. It causes a progressive degenerative lung disease called silicosis.

At the regional level, compounds and nitrous oxides are ozone precursors.

And at the global level methane contamination; methane releases contribute to the overall continuity of global warming, which has public health implications at a global scale.

This is a slide that researchers from Carnegie Mellon put together. It discusses some of the different types of equipment and their associated air quality impacts and emissions. I'll just highlight, since this has come up in previous talks.

The designation there of the major and minor sources are not in a regulatory context within the Clean Air Act. Those are merely a relative indicator of within, among those different types of equipment.

And you can see -- and I highlighted, because just to differentiate between some of the local versus the regional effects, the particulate matter and the air toxics versus the NOx and VOCs.

And also, what you note in this slide is that for some of these sources there is good data, or at least what he referred to as medium quality data on emissions, and some we know are likely impacts, but the actual quantification is still relatively poor.

So, to speak a little bit to some of the known hazards, this is an occupational alert that was released by OSHA and NIOSH based on sampling that was conducted at sites using silica sand as a proppant in hydraulic fracturing, were they found high levels of silica, such that there were concerns for occupational exposures. And this alert was sent out to -- and it actually contains a series of recommendations for best management practices, both in terms of reducing the emissions of the silica dust, which you can see in that photo, in terms of control of OBN trucks in terms of sand handling, and the like, as well as personal protective equipment required for the workers to prevent unsafe exposures.

What has not yet been evaluated is the degree to which this presents a community health hazard.

As I said before, many of these sites are very proximate to residential developments. And the buffer zones or the set-back distances between homes can be as small as 150 feet, such that what we might -- and there's no building around these. So, what we might consider a traditional occupational hazard also needs to be evaluated in the community health sphere.

Looking at this, it's a 2011 *USA TODAY* headline, "Wyoming's smog exceeds Los Angeles."

That's record levels of smog in a very rural area that actually resulted in bad-air day warnings, something never really heard of in rural Wyoming, where school kids were warned to stay indoors and not exercise outside. Something in California we do get on a somewhat relative basis, depending on where you live, but something actually, previously unheard of in Wyoming.

And this has been tied to the boom of natural gas development in Wyoming. This map is from a report that was -- an assessment that was done by the Wyoming Department of Health, where they looked at this record level ozone level set during this time period and correlated it with visits to health clinics for respiratory problems.

So, the connection between ozone and emergency department visits for respiratory problems is well-established. What was interesting here is that the connection was also seen in a very rural area, which is very sparsely populated, which is often very difficult to measure. So, it’s a significant impact.

And in this map here those brown dots are the wells. There’s a link there at the bottom, if you want to read the actual report.

So, a bunch of new studies in the past year have examined the VOC emissions as ozone precursors. That top study was done at the Marcellus Shale, in Pennsylvania. The Environmental Science and Technology Report was done in Colorado.

And what’s notable about the Colorado study, in particular, is that they have looked at the relative ratios of the different volatile organic compounds and compared them to raw gas emissions. So, they’re actually able to identify a gas signature in the levels of the various volatile organic compounds, and able to do some source attribution at their regional monitoring stations.

And so, the conclusions in this study were that somewhere in the order of 55 percent of the ozone precursors measured at that monitoring station were likely from oil and gas development.

So, a significant source and with potentially significant consequences for the region, which is the eastern slope of the Rockies, in an area that has -- is already of concern in terms of air quality.

In the other piece, I’ll note the same thing in the Pennsylvania study, which is that both -- a lot of these studies looking at ozone precursors have noted a few different things.

For air basins that are already impaired, this presents new -- oil and gas development presents an additional burden in terms ozone precursors.

For areas that are maybe a little marginal, this new development could actually push them over into the impaired status.

In the past year, the U.S. Environmental Protection Agency has begun regulatory efforts to require emission controls. These are only on new sources and they don’t begin until 2015.

So, there's a number of -- there still remains a gap in terms of the ongoing pollution from these sources that is not controlled through the Federal regulations.

At the local level there also have been some studies looking specifically at, you know, the other realm of air toxics, and for this portion we're talking about the benzene toluene, the benzene xylene range, formaldehyde, et cetera.

This is a study that was done in Colorado, again, and what they found, the proximity to well sites linked to increased levels of contaminates and health risks.

I highlighted to findings here, specifically looking at xylenes where they found a nine-fold increase at the monitoring conducted proximate to the well location as opposed to the regional monitoring conducted further away.

And at the well site these researchers conducted a risk assessment to look at the health implications of the contaminate levels and found elevated risk for respiratory and neurologic impacts.

It's important also to highlight this particular finding. In the absence of specific exposure assessment information, i.e. monitoring conducted where an individual lives, it's very difficult to draw a connection between health impacts and the exposure -- you know, and what might have caused that.

But it is important to note that a study like this identified respiratory and neurologic impacts as the elevated risk of respiratory and neurologic impacts which is consistent with many of the same types of health impacts that communities, impacted by high levels of new oil and gas development, are complaining about.

And I think as we go forward, we're going to continue to see these types of linkages between our exposure studies, our risk studies, and our health information.

Switching to water quality from the air world, a number of different sources of potential water contamination associated with hydraulic fracturing. At the surface level, waste disposal, whether that's water or solid waste, has a potential for impacting both surface and groundwater resources.

Spills, source depletion refers to the large amounts of water drawn out of aquifers, which can result in migration of other contaminants or result in shifting concentrations of environmental -- of contaminants in the aquifer, or even a draw down from the surface water into a subsurface aquifer.

In the subsurface there are a number of

different potential mechanisms by which groundwater can be contaminated, faulty well construction, faults and fractures being a conduit from one aquifer to another, or from the subsurface to a water -- an aquifer used for drinking water.

Old wells that have not been plugged properly can present a conduit for contaminants.

And fracturing that extends outside the intended formation can also result in a pathway by which contaminates can reach a drinking water resource.

The contaminates that have been raised of concern, methane, which is both an asphyxiation and an explosive hazard, other hydrocarbons, your benzene toluene, benzene xylene, contaminants, radioactivity, metals.

And then I put “other” with a question mark because of the lack of transparency on all of the inputs that go into using the hydraulic fracturing process, such that we don’t actually know all the chemical constituents of some of the fluids that are used, and some of the processes. We don’t actually know exactly what we might be testing for when we’re looking at potential contamination, so that’s a question mark.

When it comes to the drinking water contamination issue, there is basically both the concern of globalization of contaminates that already existed in the subsurface into a drinking water resource, and introduction of new contaminants down into the subsurface that can then also contaminate groundwater.

A recent study that looked at this was conducted by some researchers in Duke. And the study was done in New York and Pennsylvania. It found an association between shale gas extraction and methane contamination of drinking water.

On the axis there is the distance from a well, and the Y axis is the methane concentration found in drinking water.

The triangles reflect what drinking water wells that were sampled in areas where there was not ongoing shale gas extraction, and the circles represent ones that were taken where there is currently ongoing shale gas extraction.

That shaded area reflects a level of concern for methane in drinking water. The Department of the Interior uses a 28 -- what’s the unit here? Yeah, parts per million, milligrams per liter, as a cutoff for immediate intervention. The 10 to 28 milligrams per liter is an area of concern and below that in the no-action level.

So, to note here, the concerns are both that we see an association in terms of proximity to active shale gas extraction and also that some of the levels measured in these wells meet the criteria of an explosive hazard.

Government agencies have also been involved in investigating contamination issues and public health impacts. The Agency for Toxic Substance Disease Registry, which is part of the Department of Health and Human Services, has done something, what they call health consultations.

This one was done in Garfield County, Colorado, and found elevated benzene levels in the area of well sites.

There's an ongoing Environmental Protection Agency, the U.S. Federal Environmental Protection Agency investigation into groundwater contamination in Wyoming, where both methane and hydrocarbons were detected both in shallow water, and also in deeper drinking water resources.

This here is the title for a *Medical News and Perspectives,* in the *Journal of the American Medical Association*, or JAMA, and it says, "Rigorous evidence slim for determining health risks from natural gas fracking."

And it speaks to major data or information gaps that are needed in order to really understand health impacts.

So, I've highlighted a few of these needs here. A need for a comprehensive chemical disclosure so you know what types of contaminants are being introduced, potentially, into the environment, the monitoring of emissions, releases and waste.

Because many of the wastes are currently exempt from some of our standard environmental laws we don't have very good monitoring data on what's being emitted, nor do we have it actually on ambient or targeted monitoring.

So, when I refer there to targeted monitoring, it is the kind of monitoring that you go out and sample an individual's well, or the air quality around an individual home.

Ambient monitoring, I'm referring to ozone monitoring networks, many of which are not located in these rural areas most impacted by this boom in oil and gas development.

The same thing in terms of the lack of good surveillance network for groundwater quality in rural areas, and so we don't have the essential information to understand when there might be a contamination issue.

And lastly, I've highlighted here the need for health impact surveillance. Surveillance is the public health term for monitoring. So, that's where we're looking for those indicator health impacts, the spikes in emergency room visits, the visits to the clinic, the early warning signs that we might be seeing in the human population in terms of health impacts.

And there are also -- you know, that was sort of the data information gaps.

There are policy gaps that also are contributing to the threat to public health. Oil and gas development have a number of different exemptions from our Federal environmental laws. They're listed here.

Safe Drinking Water Act, Clean Water Act, Clean Air Act, RCRA, NEPA.

These exemptions have contributed to the lack of good monitoring data and good emissions data and which severely hampers our ability to understand the public health impacts. And it severely hampers the ability for local or regulatory -- our State agencies to answer the questions when communities come to them with concerns about their health, when they have a well 300 feet, 500 feet from their home.

Similarly, we have a -- with the lack of the Federal, of good Federal laws, we have a patchwork of state regulations across the country resulting in really very low level of protection provided to communities, both in terms of the requirements for distances from wells, to sensitive sites, which are homes or schools, and also in terms of resources available to respond to spills, to events, to emergencies, to the regular monitoring, to investigating violations, and the like.

A recent analysis was done out of the -- I believe he’s on the University of Pittsburgh, the School of Public Health, on some of the Federal Advisory Committees that have been set up to examine the hydraulic fracturing in oil and gas development significantly lacked individual public health expertise.

And although it’s incredibly important that those advisory panels are part of the public discourse in the policy setting, and many of them include experts in environmental examinations, it’s also very important to have folks from the public health world as part of those policy discussions.

And, lastly, in my conversations with researchers across the country working on this, and we’re seeing -- we’re beginning to see more comprehensive research, but it’s essential that we have adequate funding for the research that will provide the answers to the questions that are on the minds of any of the communities living adjacent to this new development.

So, lastly, just a series of recommendations for the protection of public health and safety; we really need a comprehensive assessment of environmental and health threats.

These are not -- you know, we do not currently have this information. I've identified a number of the information and policy gaps that we are faced with right now, meaning that we don't have good information in order to assess the potential repercussions from a public health perspective.

And we have a number of studies that point to significant threats and that's a bad combination, in my mind, in terms of protecting public health.

We need strong Federal and state policies to prevent damage to the environment and public health.

So, these are all things that I've just been speaking about, improved monitoring of contaminant emissions and environmental conditions and, lastly, increased funding for research, investigation, studies and surveillance.

And I'm happy to answer any questions.

MR. RHYNE: All right, thank you very much, very much appreciate it. I'm sure we'll have some more questions as we go.

WE do have our next presenter here in the house. It will just take us a moment, I think, to get his presentation loaded up. We have Tim Kustic from the California Department of Oil, Gas, and Geothermal Resources here with us today.

So, let me -- if I can see. Here we go.

So, as I'm sure some people are aware, here in California we do have oil and a small amount of gas reserves that are extracted using a hydrofracturing technique.

And the Department of Oil, Gas, and Geothermal Resources has responsibility for regulating that activity. And they're working on some proposed regulations and so we've asked them to come and talk about that this afternoon.

So, Tim, I think the floor is yours, sir.

MR. KUSTIC: Okay, thank you. It's just one correction, it's I'm actually with the Department of Conservation, the Division of Oil, Gas, and Geothermal Resources. That's all right.

Well, thanks for inviting me here today. Before I start talking about the draft regulations, I just want to give you an overview of hydraulic fracturing in California because it's significantly different than what you hear about in most of the media.

In California, hydraulic fracturing's been used for 50 years to stimulate oil production. It is not used for dry shale gas production. And that’s -- I know this is a seminar about gas, but when it comes to hydraulic fracturing in California, it’s all about the oil, rather than the gas.

So, just kind of a quick review of hydraulic fracturing -- okay, so the mouse isn’t working.

So, assuming this here is a productive interval, maybe this one, this one, and perhaps even something down here. Historically, in California what hydraulic fracturing, and even today, what it’s being used for is to go into a conventional reservoir, that is a reservoir like this that has -- this is a simplified reservoir but, basically, it’s a reservoir that has some kind a structure, in this case it’s an incline, that’s trapping oil.

And in some reservoirs you have a gas layer on top of the oil but this one, just for simplicity, just has oil.

But there’s some kind of a bend, or fold, or faults, as an example, that is causing traps of oil and that’s called a conventional reservoir.

So, operators will go in and fracture stimulate one of these intervals, generally vertical wells, and it will be stimulated at perhaps 30 feet, maybe 100, 150 feet and fracture stimulate that interval for -- the fracture stimulation operation may take 20 minutes, it may take an hour or two.

And then they'll put the well into production for perhaps the next 20, 30 or 40 years. Generally, it's a one-time operation as part of the completion and stimulation of a new well.

That is a lot different than what has gotten a lot of attention throughout the country.

Now, as I indicated before, they use it in California for conventional reservoir, pretty much in the existing oil fields. The oil field's there because that conventional structure was there, the well needs to be stimulated to increase production.

What's happening in places like Pennsylvania and New York is a technology -- two technologies that have been around a long time in the oil field. One is the ability to directionally drill. That was refined to the point where they can take a hole and turn it from vertical to horizontal, and drill it up to two miles long and more horizontally.

That's very helpful when you have long, horizontal shale beds that have gas contained within the fore structure and you want to access as much of that shale rock as possible.

So, they've taken that technology and then with the advances in hydraulic fracturing, again the technology’s been around more than 48, 50 years, they can fracture stimulate, over the course of many days, this long, horizontal section, fracture stimulate perhaps 10,000 feet of reservoir rock.

That’s a huge amount of reservoir to be stimulated and we don’t have operations like this in California.

This is also an unconventional plate. That is there wasn’t previously -- in most of these areas there wasn’t previously a conventional reservoir, so there wasn’t an oil and gas industry developed.

So, industry is coming into areas that now, with this key to unlock shale gas, they’re coming into areas that didn’t have an oil and gas industry. They’re putting in well paths, they’re putting sumps and pits in places, they’re using some significant water resources to fracture stimulate.

To fracture stimulate a 10,000-foot section it could take, you know, 2 million, 5 million, up to I think the highest I’ve heard is 13 million gallons of water to fracture stimulate that.

The largest frac job that we know of in California is 1.5 million gallons. The average frac job in California is about 250,000 to 300,000 gallons of water.

Just to give you some reference, an average hotel swimming pool is probably about 250,000 gallons of water. An Olympic-sized swimming pool is about 600,000 gallons of water.

So, the magnitude of water being used for shale gas development is, you know, incredibly large compared to a typical frac job in California.

Additionally, ever well that is drilled into a shale gas reservoir has to be fracture stimulated, otherwise it’s not economic.

In California, the vast majority of wells are not fracture stimulated. The vast majority of oil deposits in all reservoirs, oil fields don’t need fracture stimulate to produce.

In California, we’re drilling about 2,500 to 3,000 new wells a year. And based on the data we have now, it looks like about 700 wells a year are being fracture stimulated in the State, so it’s a subset of the wells.

So, there has been talk of the Monterey Shale. The Energy Information Administration came out and said there’s up to 15 -- there could be up to 15.4 billion barrels of recoverable oil in Monterey Shale. The Monterey, itself, has been productive for many years.

It is productive for its tracked-through conventional mechanisms and it's also the source rock. That would make it a reservoir rock if the oil is trapped in the Monterey, itself. It's also the known source rock for most of the reservoirs.

That is the oil was formed in the Monterey and then over eons of time it migrated up and was trapped in the higher reservoirs, in conventional reservoirs. But most of the oil in California came from the Monterey. So, the Monterey has been studied and is well known.

What could be coming our way, and certainly is not here yet, industry could be -- they're already looking into can they use horizontal wells and can they use larger hydraulic fracture stimulation operations to kind of unlock the key in the Monterey?

The Monterey's already fractured, it's a naturally fractured reservoir, the shale's been naturally fractured.

And the current production in the Monterey is from those fractures in the shale.

So, industry's saying, they're looking into to determining whether or not if they fracture stimulate, they can get more production out of the Monterey.

To date there hasn't been a big increase in hydraulic fracture stimulation in the State. There has not been a big increase in production. There has not been a big increase in wells drilled. But the potential is out there, we realize that, and that’s why we’re moving forward with some regulations.

Existing regulations, which there are plenty in California when it comes to oil and gas, but the ones that we carry out now deal mainly with the well construction. That’s the requirement to have casing, have the casing cemented, and to have tests of this to make sure it has integrity.

It requires the protection of fresh water. We’ve had requirements for the protection of fresh water for nearly a century in the State, through oil and gas operations.

So, this well construction and standards applies to all wells. Not just the subset of wells that hydraulic fracture stimulate, it applies to every well. Every well has to have this robust well construction.

In some states of the country they’ve recently passed what they’re calling hydraulic fracture stimulation regulations. And what they are, they’re passing regulations similar to this that we’ve had on the books for many, many years.

We’ve also heard comments -- I’ll talk about the regulations in a minute, but we’ve had multiple workshops and people have said, well, how come your regulations are only nine pages and New York’s is 50, or 60, or 70 pages?

Well, you know, California, unlike a lot of other states, if you had an industry representative here, I don’t know if there is one, but they could probably give you a ballpark idea of how many different regulatory agencies there are in California when you go to drill a well.

In California, our hydraulic fracturing stimulation regulations are only going to deal with our authority. In other states, hydraulic fracturing regulations may be dealing with groundwater use, where they’re getting their resources, air emission issues, and air quality issues, land use issues. Those are all outside of our authority.

So, our regulations, just based on the nature of the two different state governments, our regulations are probably going to be smaller than a lot of other states because the way the government is structured in California there’s multiple agencies regulating the oil and gas industry. And our regulations are going to be very specific to well construction into the subsurface.

So, we do have -- you know, hydraulic fracture stimulation is not unregulated in the State. Every well in the State is regulated, including those that are hydraulic fractured stimulated.

What we don’t have is we don’t have real good data on the practice because it’s well stimulation. It’s not a change in the mechanical condition of the well. And when you fracture stimulate, that’s what’s represented here by these cracks, in this diagram, the well is already perforated, the casing is already set. The setting of the casing, the perforating of the well, or any plugging of the well with cement all requires a notice and permit, so we have data on that.

Well stimulation and hydraulic fracturing is only one method of well stimulation. It does not require a permit. It’s not in the law, it’s not in the regulations.

So, that’s why when folks ask us how many wells have been hydraulic fracture stimulated, we can’t push a button on our database and say this is how many.

We’re starting to capture that data now. We’ve been doing it for over a year on our data management systems.

And we went out to industry and we asked them to voluntarily start reporting, on FracFocus, their operations. And the last time I looked, I think there’s over 800 frac jobs now reported on FracFocus.

And, of course, that’s just voluntarily because we need the regulations in place before we can require it of industry. But that’s where we are headed.

So, on this path, which we started more than a year ago, we started by going around the State and holding seven information-gathering workshops, where we met in the evenings. I think they were two-and-a-half to three-hour meetings.

We invited the public in. We explained hydraulic fracturing in California, much as I just did. And then we asked them for their input, their concerns, the topics they’d like to see discussed in our regulations.

And, of course, we heard a lot more than what we had authority to. We heard things like, well, you need to find out where all the water is coming from. Well, that’s beyond our authority, we’re not a water management agency so we can’t put in regulations to tell us where you get the source of water to do the fact job. We don’t have the authority to do that.

So, we took input from interested parties. We had workshops in Bakersfield, Ventura -- well, pretty much all of the oil producing provinces, Bakersfield, Ventura, Long Beach, Culver City, so we did two in the L.A. Basin, Sacramento, Salinas, we did Salinas, and

Monterey.

So, after that process, which ended late last summer, we sat down and we wrote what we called a discussion draft of the regulations. And that we released mid-December of last year.

And then we started in, I believe it was February, though it may have been late January, but I believe it was February we started having workshops, now, to discuss the discussion draft of the regulations.

And these were running for about seven or eight hours. We did one in L.A., Bakersfield, Sacramento, last week we were in Santa Barbara and next Tuesday we will be in Monterey. Those are the -- that's the last scheduled workshop.

In addition, of course, we encourage people to send us comments, you know, via e-mail, or you can simply write them to us.

So, in these workshops we're going step by step through these regulations that we're going to discuss, now, and I'll -- that's what I'm going to go through now is the regulations, what we have in the discussion draft.

And I'll give you some idea of some of the feedback here.

So, the first part, this is not necessarily how

-- if you have downloaded our regulations, they’re on our website, but I didn’t bring the regulations. I didn’t want to sit here and read the regulations. I figured I would put everyone to sleep at this hour.

And so, I’m using the Power Point that just has the highlights.

But the regulations are on the website and you can download and print them. But this Power Point doesn’t necessarily follow the regulations in the path they are written. We’ve covered it more logically in the course of what would happen in the process of making sure you comply with these regulations before you do the process of hydraulic fracture stimulation.

So, the regulations require before the operator can even, you know, consider having equipment out there on the site, they have to do, you know, a fracture radial analysis. And that’s where they look at the fracture that they propose to conduct on the well.

Well, the start with the well bore. They look at the well bore and they make sure that the well bore has good cement, that the casing can hold the pressure. You’re probably going to do the casing pressure test, though, once you -- well, you probably have recently done one. In most cases in California, because most of the wells that are fracture stimulated are new wells.

So, you do want, when you first put the casing in the well, but before you actually start pumping on the frac job you have to do another one, essentially.

But this fracture radial analysis is you look at the well bore, you model whatever the model for the fracture is. You know, whether it be 200 feet or 1,000 feet, the operator has to double that distance, and evaluate the area around that to make sure that there's no abandoned well bores or even active well bores that might be a conduit for the fracture to reach that, and then somehow migrate somewhere.

They have to look for if there are any faults there, is it a ceiling fault? Is there any possibility that the amount of pressure reaching the fault, if it's an active fault, could stimulate the fault?

Or any other subsurface geologic condition that could be of concern. So, that has to be done.

Basically, that has to be submitted to us -- oh, I should -- in the next section we'll talk about that.

So, they have to do the fracture radial analysis. They have to evaluate the cement job on the well, and then they have to pressure test the well. And they have to pressure test all of the surface equipment before they start actually pumping the fracture stimulation job into the well.

So, this second section we covered, and this is in the discussion draft regulations. Again, we haven't even started the formal rulemaking, yet.

But they have to give us at least ten days' notice prior to conducting the hydraulic fracture stimulation. And that ten days comes from the notice and permit cycle that's been in the statute for many, many years. That's when they're going to rework a well or drill a well.

The current practice is they give us ten days, we evaluate the notice and we either respond back that here is your permit, or we respond back it's going to take us longer, or this is deficient for this reason, but we have to respond in ten days.

So, that's where this ten days came from. And we're hearing a lot of comments about the ten days that it's insufficient. Because what we're hearing, and this is something different than what we do in the normal permitting operations within DOGGR, what we're hearing is, well, for public input and public comment, you know, that's usually 30 or 60 days.

So, this ten days, we've already heard a lot of comments and that's more likely going to change to address the input that we're receiving. And that's where the ten days comes from.

And then, once we get to the, what we call the HF1, which is the new form that the operator would submit, along with that fracture radial analysis, and the cement bond logs, all of that data that was required earlier, they submit it along with this HF1.

And then we're going to post that HF1 out on our website, so any interested party can take a look at it.

And then, prior to actually conducting the fracture stimulation operations, the operator has to give us at least 24 hours' notice so that we can have our field engineers out there. And that's -- 24 hours is more than adequate for that. Quite commonly, we only get three or four hours' notice for some operations.

The Division has field engineers on call 24/7 to, you know, respond to various field tests, so this would just be another field test that they're out there witnessing.

And for the most part fracture stimulation is not done -- it tends to be done Monday through Friday, during daylight, just because it's one of these operations that you have more control over versus drilling a well. When you drill, you have to do it all 24/7, so scheduling will probably be a little bit easier for these, for us witnessing these tests.

So, once they're out there doing the fracture stimulation, we’re going to require continuous monitoring of things like pressure rate, and proppant concentration.

And then, if there’s some kind of upset from what should be expected, then the operator has to, you know, investigate that. You know, shut down operations, figure out what happened.

If there was some kind of a breach in the casing that led to a failure, then they would have to stop and they would have to address that, remediate it before they can go any further.

And then after the fracturing, operators right now have to tell us the amount of oil, water and gas produced in wells, and they report that to us monthly.

But in these regulations they have to monitor that daily for the first 30 days, and then monthly for five years after that. And they have to maintain records of their monitoring.

Not necessarily that it has to be reported to us, but if we need to investigate, they have to have the records available.

And we’re getting various comments on a number of these items.

The disclosure, this has been a hot topic, the disclosure of the chemicals used in hydraulic fracturing operations. Right now, operators are voluntarily using FracFocus and the model we've come up with in these discussion draft regulations requires operators to use FracFocus.

Now, FracFocus was developed by the Groundwater Protection Council. And the Groundwater Protection Council is a council of state regulatory bodies that are involved with either groundwater monitoring, groundwater production, groundwater regulation. It's not industry. It's a number of States, California's a member. And, in fact, I sit on the Board of Directors of the Groundwater Protection Council.

FracFocus was also developed with the Interstate Oil and Gas Compact Commission, which is a compact of those states that have oil and gas production. The Governor is a member. Mark Nechodom is his appointee. Mark Nechodom is the Director of the Department of Conservation, essentially my boss, and he sits on -- well, he's essentially appointed to the Interstate Oil and Gas Compact Commission.

So, it was these two bodies that are -- that have oil and gas production within their -- well, they don't have it -- excuse me, let me start over again on that.

States with oil and gas production are members of these two organizations, the Interstate Oil and Gas Compact Commission and the Groundwater Protection Council.

So, it’s the states that have really come together and created FracFocus.

There’s been a lot of comments about should we be using FracFocus or should we be using some state database?

The beauty about FracFocus is it’s there now, we don’t have to build it.

If any of you, in the course of your career, have been involved in building a state database system, I have to some extent, and I can tell you having something right now that you can use is a lot better than starting at square in the State system to build a database.

The regulations do indicate, though, if FracFocus isn’t available, then the State has to develop their own system.

But the model we have right now is FracFocus first. And, of course, that could change during all of the discussions.

Trade secrets, this is something that’s well beyond our authority. We do not control trade secrets. But some of the service companies that are supplying the frac fluid and conducting the fracture stimulation operation are -- they have trade secret protection for some of the -- for the recipes for some of the chemicals that they use to give the frac fluid the properties necessary for a successful frac job.

So, our regulations and FracFocus require you to give the chemicals, the chemical family, but the actual recipe, if it's a trade secret, it's just going to be indicated like it is now, and FracFocus is the trade secret.

The regulations do go further, though. They say that if we need that trade secret information to investigate a spill, an unauthorized release, we can get it.

It also says that if some other agency, say the Regional Water Board needed it, they can get it.

It also goes on to indicate that if medical professionals, I'm not sure -- I thought that was on there somewhere.

But if medical professionals need it, they can get it, too.

And then there's provisions for in the event of an emergency, for medical treatment that, essentially, they could get it right away and then the paperwork would have to follow kind of behind it.

But it does require that if it's released -- oh, there's the medical part. If it is released, then it has to be maintained as confidential.

So, if it was supplied to a medical provider, they would have to sign some kind of a confidentiality agreement.

And this is all trying to fit in with the trade secret protection. DOGGR and the State does not want to get caught in a lawsuit where they've provided something to us that's a trade secret, and now we have a Public Records Act request that, potentially, we would have to divulge a trade secret and now we're going to be hit by a lawsuit from a service company. That would be very problematic.

So, our attorneys are working carefully on this section to make sure that we're not exposing the State and the Department to some kind of major potential liability.

The storage and handling of hydraulic fracturing fluids, for the most part this section kind of follows up or it just reaffirms what's out there right now in various regulations.

There's already regulations that have a spill plan that addresses the fluids that are on the site. So, if hydraulic fracturing fluid is out there, it has to be addressed in the spill plan. It has to have secondary containment if it's not fresh water. It has to be cleaned up. These are already requirements that are in the existing regulations.

It can't be stored in any unlined sump. I don't think that's standard practice in California. Actually, sump usage for this is not a standard practice in California, anyhow, so I don't think that would be much of a challenge.

But there's a couple things that come into play here when you talk about handling the hydraulic fracturing fluids that are significant -- in California, they're significantly different than when you're doing dry shale gas that I want to point out.

In California, as I indicated, hydraulic fracture stimulation is used in existing oil fields. Existing oil fields, the fluid coming to the surface is anywhere from -- if they're lucky, it's 50 percent oil. But it's usually, you know, 90 to 96 percent brackish water. Water that's not -- except for in a few fields where they can actually clean it up and use it for other purposes, most of this water is ITS water that's just re-injected.

So, when you fracture stimulate in California, first of all, you're not going into a rock that's dry, that doesn't have any fluid in it. So, when you put fluid in to fracture stimulate, you need less of it. But that fluid is injected, it fracture stimulates the rock, you put the well in production and that fluid comes back along with the produced water, along with the produced oil.

It then goes into the production system which, in California, is an enclosed system. I mean, it goes down flow line, to a separator, the fluids are separated out and the water is re-injected for pressure maintenance, that's the most common use, or it's sent over to a disposal well for disposal.

That's a lot different than when you're doing shale gas and you build an infrastructure in a gas field that you know is not going to have water production. The only water that's ever produced is the water that you take out there to fracture stimulate. So, you're not building an infrastructure for water production because you're not -- when you produce this well for the next 10, 20 years, you're not going to have water production.

So, when they flow back a dry shale gas well, you have a large amount of water that comes back and has been, I'm not sure what the practice is in every state and I know they're trying to get away from this, but in many cases it’s put into a pond, hopefully, a lined pond. And the methane that’s with that water, because you fracture stimulated a rock that had methane in it, is just allowed to escape.

That doesn’t happen in California. We don’t -- many of our districts wouldn’t allow anything close to that happening.

In California, it comes back to a production system where any gas is scrubbed off, any oil is sent to production and the water is re-injected.

So, it’s a lot different when you’re talking about dry shale gas versus hydraulic fracture stimulation for oil production in California.

And even looking forward, what’s the -- I guess the information that’s out there, that has risen, that has drawn some concern is this idea that in the future the Monterey is going to turn into, you know, a real game changer, potentially, in California.

But if you talk to the industry, you’re still looking at the Monterey for oil, not for gas. So, it’s still going to be an oil field production system where it’s pretty much enclosed.

So, I don’t see the unlined sump storage being much of a challenge for industry to overcome because I don’t think, for the most part, produced frac fluid, when it comes back is not put into pits currently. And I don't envision that being a common practice in the future.

The other thing that's a bit different with oil production versus dry shale gas is that dry shale gas, when you produce back and you get the fluid back you know it's frac fluid because there was no other fluid out there.

That's not the case when you're talking about oil. Like I said, 90 percent of it is fluid. So, you've injected water into high TVS water and when you bring it back it's really hard to tell what is frac fluid and what is not. I mean, unless you have some kind of a tracer in there you would have a hard time identifying the frac fluid from the produced water.

And some people have characterized the spent frac fluid as waste. That's not always the case. In many oil fields in California they -- every bit of water that they produce they re-inject to maintain the reservoir pressure. They actually buy water, fresh water, or not so fresh water, and re-inject it to maintain the reservoir pressure.

So, you've fracture stimulated perhaps with 300,000 gallons of water and you put it down the well. When that comes back the industry would not, in some cases, characterize that as a waste fluid. They would consider that as a viable product they could use for the water flow.

So, things are a little bit different in California when you're talking about hydraulic fracturing for oil versus shale gas.

But, certainly, we know that there is the potential for a greater use of hydraulic fracture stimulations so want to make sure that we have regulations in place that captures the best practice of the industry to make sure we know where it's going, to make sure things are being operated correctly.

We want to make sure that we're out there and being able to witness it.

I think one of the reasons we haven't seen any problems from hydraulic fracture stimulation in California, even though it's been used for 50 years, one of the big reasons is that it's a huge financial investment for the operator. And that, alone, is an incentive to do it right and do it correctly, because if you don't, you risk the potential of damaging your well or, basically, wasting a lot of money that you just spend to fracture stimulate because you didn't do it correctly.

So, I think that's really helped with the practice not being a problem so far.

I think that's all I have for slides. Yes. So, is there questions or -- okay.

MR. BRATHWAITE: Again, thank you for that presentation. One of the big issues that have come up as a result of hydraulic fracturing, well, mostly outside of California, but I'm sure it will arise here in California, too, is the potential for groundwater contamination.

Can you give us any idea of if your department have heard of cases of that happening here in California or as a result of hydraulic fracturing, where we've had cases where the water has actually been contaminated as a result?

MR. KUSTIC: As a result of hydraulic fracturing, no. But we're not aware of any cases where hydraulic fracturing has led to contamination of the aquifer.

You have to remember that in California we have -- we've drilled over 215,000 wells in the State. So, although hydraulic fracturing is just a well stimulation that, you know, takes an hour over the course of many decades of well operations, most of the wells are out there moving fluids back and forth through that freshwater aquifer behind steel casing, steel tubing and cement. That’s been going on for a century in California.

So, the idea that hydraulic fracturing, which is just a tiny subset of the fluid that’s moved up and down sells in the State, you’d be looking -- essentially, you’d be looking for the needle in the haystack. Of all the water that’s injected in the State annually, which is in the order of 3 billion barrels of fluid annually that gets injected in the State, hydraulic fracturing stimulation, when they actually are injected it in and stimulating, represents .02 percent of all that water.

So, there’s far greater risk of contamination of the aquifer or other zones from just the normal production and injection that goes on in the oil field operations.

And there have been cases where there have been casing failures and there has been contamination. And those cases -- but it’s not hydraulic fracturing.

In those cases, we immediately notify the water boards. We have the authority to tell them to repair the well, but we don’t want to tell them to go tell them to fix the hole in the well if the water board’s going to tell you need to produce back out of that hole that you were injecting fluid. Well, now, we want you to produce out for the next six months to make sure you clean up any contamination.

So, we work with the water boards in cases like that to make sure that, you know, if there was a failure, there was some kind of remediation.

But for the most part, given the number of wells there are and the volumes that are being moved through the aquifers, behind these protective layers, industry has done a remarkable job of not contaminating aquifers throughout the State.

MR. BRATHWAITE: What about the possibility of the frac -- once the frac has been established? I mean, is it possible that these fracture zones could be misdirected and end up places that we don’t intend and, thus, contaminate some of the sensitive zones?

MR. KUSTIC: Possible, but not very likely. When they do fracture stimulation, I’ve got a slide up here, they’re targeting this zone here. And perhaps they might get a thousand-foot frac if they model it great, and they have enough pressure.

Typically, in California, fracture stimulation occurs depths of 5,000 all the way down to 10,000 feet. We do have some that’s shallow, but in the areas where it’s shallow there is no freshwater aquifer.

Some of the western side, the western half of Kern County there’s not many aquifers over there. So, t here's some shallow, but there's no aquifer to contaminate.

But if you were to somehow get a fracture to migrate -- in fact, our regulations require that if the length of your fracture could leave the reservoir rock and impact the cap rock that's confining harder or denser rock, then you have to evaluate the cap rock in addition to the reservoir rock, to make sure that that cap rock would actually be strong enough to stop that fracture.

But if you're talking about 5,000 or 6,000 feet and you're trying to get a fracture all the way back up to, you know, a freshwater table, the deepest in the State, you know, 1,500 to 2,000, most of it, especially what's being used is more -- you know, less than 1,000 feet.

But, realistically, when you start looking at the physics to do this, you'd have to set off some kind of a nuclear device down here to get a crack that far. I mean, that's how strong the rock is.

MR. BRATHWAITE: Okay, thank you.

MR. RHYNE: I actually had a question. You mentioned the Monterey shale and the kind of potential, but obviously not immediate potential for development of gas resources from Monterey, if for some reason the economics change and industry starts to look in that direction.

Do you have any current estimates of what the Monterey shale play, how much gas might be there and what the production profile or rates might be? You know, obviously, I might be asking you to speculate a little bit, but do you have any numbers like that?

MR. KUSTIC: No, our agency doesn't really do forecasting. Most of the hydrocarbons in the Monterey is oil versus gas. There certainly is some gas.

But probably the Energy Information Administration that has looked into it, is probably a better source of the information than we are.

MR. RHYNE: Are there any other questions in the room?

Any questions online?

Okay, so thank you very much, Tim.

So, before we move on to our last presentation of the day, I want to just pause for a moment and open the floor to questions for either of our two presenters on fracking, either from the NRDC or from DOGGR.

So, are there any other questions, broader questions?

Go ahead, Leon.

MR. BRATHWAITE: I don't want to dominate the events here, but I have a question for the presenter from NRDC.

Miriam, I was wondering does the NRDC have a position on hydraulic fracturing in terms of whether there should be more stringent regulations, or should the procedure be banned altogether? What exactly is the position of NRDC on this matter?

MS. ROTKIN-ELLMAN: Our concerns about the regulatory and data gaps that I presented have led us to have a position that until we have the proper safeguards there should be no new hydraulic fracturing.

MR. BRATHWAITE: Okay, thank you.

MR. RHYNE: Thank you very much.

We're going to move on to our last presentation of the day, which is Leon Brathwaite. And he'll be talking, keeping with our shale -- sorry -- keeping with our shale theme for the afternoon.

He'll be talking about the shale uncertainty cases. Leon.

MR. BRATHWAITE: So, I will introduce myself again, for the tenth time, I guess.

I'm Leon Brathwaite. I work here at the Energy Commission, in the Electricity Analysis Office to be specific.

And I'll be talking about the shale uncertainty cases, you know, taking a sort of scenario approach.

Now, I want to be clear about these cases. They are not necessarily cases that we consider plausible. They are not necessarily cases that we -- they may not even be possible.

What we are trying to do here is answer some specific questions and I think Ivin touched on that this morning.

We are trying to answer the question of what if? What if these conditions that I'm about to lay out do occur? What would happen? What would be the impact on production? What would be the impact on supplies? What would be the impact on the development of shale resources?

So, let me just get into my presentation and we'll see where we go from here.

So, as you know, there has been a great amount of controversy that have been generated as a result of the development of shale formations throughout the lower 48.

And there have been many, several areas, but the big ones have the possibility of the potential of groundwater contamination, the possibility of increase seismic activity, and that is a concern here in California, given how often the world shakes around here.

Then the diversion from freshwater as a result of hydraulic fracturing, that’s a concern. And, of course, any emissions, methane and others that may end up in the air.

So, all of these things have been a source of great concern.

As a result of this, decision-makers, policy-makers have been taking a second look at some of the policies that are, you know, on the books as a result of involving the development of these resources.

And some jurisdictions have taken different approaches to trying to deal with the development of shale natural gas.

For example, New York have delayed the development of its shale resources. The Marcela shale, probably the largest shale resource that we are aware of at this point in time, a big portion of it lies very close to some pretty sensitive areas in New York, in the watershed areas, in particular, and they have some great concerns about that so, they are taking a very hard look at how, and when, or if they will develop that resource.

Other jurisdictions, Pennsylvania in particular, have instituted environmental fees. Other states are also looking at doing the same thing.

Others are tightening regulations. And we are seeing that ongoing right here in California, as Tim laid out for us that we are looking at tightening some regulations here in California. Other states are doing the same thing.

But all of this, all of this, all of what is going on with the development of shale is occurring with a background where we have a great technological innovation going on in the oil and gas industry right now, hydraulic fracturing and horizontal drilling.

Now, as Tim said, these technologies are not new, but they're having some improvements in them and the innovations are continuing as we speak.

Hydraulic fracturing has been going on for 50 or 60 years, but there have been a lot of concerns about the procedure.

Okay, so I will be talking about four shale cases. Now, we are specifically going to look at shale, okay. We are not going to be looking at the conventional resources out there right now. We are specifically looking at shale.

We look at four cases. We look at shale abundance, shale reconsidered, shale expensive, and shale deferred. And I hope the names are explicit in the sense that it tells you what we are going to try to do here.

In order to take a look, a deeper look at these things we have to look at four -- or are going to look at four important variables. One of them is changes in the supply cost curve.

The second is changes in the time of availability of some resources.

The third is changes in the environmental impact fees.

And the fourth is changes in the rate of growth of technology which, of course, is a big deal right now.

And we will start -- all of our cases will start with our reference case. That was the case that Ivin spoke about this morning. No, it wasn’t this morning, it was this afternoon. Pardon me.

Okay, but let’s talk about that case. Now, of course, that case is still -- we are still doing some work with that and whenever we get done we will be starting with these cases, and we’ll start with our reference case and develop these cases as a result.

In the shale abundance, of course we begin with the reference case, the change in the supply cost curve. We’re looking at an expanded resource base. All known shale formations will be developed.

In this case, in this world of shale, cost estimates we believe will be 15 percent low, and as a result we make an upward adjustment of the curves of the supply cost curves.

Hi, Commissioner.

In terms of the availability of resources there are no delays in production hook-ups in this shale world we are considering.

On the environmental impact fees we'll be on the low range, we'll have like 30 cents for Mcf in terms of any environmental impact fees, mostly because of water handling. I mean, there's a lot of water that are used in these -- in hydraulic fracturing.

Both the water that is used in -- that is pumped into the reservoir and water that is extracted, and there's a lot of handling that must be carefully done, and the water must be treated as a result and all that.

So, we are going to assume in this shale world that only about 30 cents per Mcf production will cover the cost of those things.

In terms of technology and innovation, we assume the technology will grow at 2.5 percent, which is pretty high relative to the reference case. I think in the reference case we only have like 1 percent or something like that.

Now, in terms of shale reconsidered, again, we begin with the reference case.

But in this case, and this is a shale world that we're creating, we have the concerns about hydraulic fracturing will delay further development of shale formations.

We'll have targeted moratoriums. We'll look at specific areas where we believe that it will go off limits. For instance, like New York. New York will go off limits. There are some parts of Pennsylvania that will go off limits. Certain parts of Ohio and certain parts of the Rocky Mountains will go off limits.

And as a result of that, we are thinking that we may end up shrinking the results of these by 15 percent.

In terms of the availability, we'll see significant delays in terms of hooking up new production. We're thinking about three years.

Environmental impact fees will be on the higher end of our range, and we're thinking about 55 cents per Mcf.

Technology and innovation will grow at the rate of the base case, which is about 1 percent.

In shale expensive, now the shale expensive sort of looks like the previous case, but they have some differences that should be explored.

We will begin with our reference case. The resource base, though, will remain unchanged as compared to the reference case.

In terms of a hookup of new production that will take about three years because of the environmental challenges.

Environmental impact fees, here is where is going to be a big, significant change. Well, these are higher than our highest value on our range and we are thinking about 20 percent higher, so we are talking about 67 cents per Mcf higher in terms of the environmental impact fees.

Technology, though, will be cut in half compared to the reference case, so it will only be a half a percent. The reference case is about 1 percent in terms of growth in technological innovation.

Here, we're only going to develop about a half a percent in the shale expensive world.

In shale deferred, in shale deferred will begin with the reference case, the supply cost curves will remain unchanged from the reference case.

But the hookups will be even more delayed than previously. Here, we see delays in the three- to five-year range, but closer to the five-year. Most of the new production will not come on for maybe four, four and a half years, maybe.

Environmental impact fees will be on the high range, about 55 cents per Mcf.

And technology will grow at the reference case rate of about 1 percent.

With that, I will end my presentation. But the thing that I want to say here, before I leave, we are not talking about trying to answer all of the concerns or questions that come up as a result of shale development.

We are just trying to answer specific questions of what if? What if these things occur, what will be the impact upon the market in terms of its production, in terms of shale development? That is what we are trying to answer.

We're not looking at -- we're not talking about the likelihood of occurrence, we're just talking about possible impacts.

With that, I'll take any questions that you may have. Thank you very much for listening.

MR. RHYNE: All right, thank you, Leon.

So, we've had all of the presentations that we had scheduled for the day and, once again, I appreciate everybody's flexibility in staying with us.

It's been relatively quiet with regard to public comment thus far. I would hope that either some of the folks who really have some thoughtful input on this are either -- have been waiting for this time of the day to share their input or, perhaps more likely, will be formulating their input with regard to written comments, such that you can share more precisely some of the estimates, impacts, and thoughts that you have.

But we will stop here and I will ask -- this is an open forum at this point with regard to natural gas issues and natural gas modeling.

So, I'll open the floor, first, to folks in the room. Are there any final thoughts, comments or questions to share from the public?

Okay, second of all, we're going to turn to the folks online and ask if there are any questions or comments from the folks, from our online participants.

Yeah, there is a question about whether or not presentations will be posted online. We will get them online either later today or first thing tomorrow, so everyone will have an opportunity to download and take a look at these.

Any other questions online?

Okay, and seeing none Commissioner McAllister, you've joined us here as we've reached towards the end. I would ask if you have any closing remarks?

COMMISSIONER MC ALLISTER: Yeah, I was hoping to catch a little more at the tail end, but scheduling prevented it. But I trust you had a good afternoon.

And I have been reflecting a little bit on the morning, which I enjoyed. And I guess, you know, it sounded like that the -- essentially, the utilities that spoke, you know, both Northern and Southern California, you know, all over the State there's really -- on the storage issue, it was kind of surprising to hear that there really wasn't an anticipated need for new storage.

I guess, particularly, just being aware -- been expecting to hear a different message as far as Southern California, particularly San Diego that, you know, given some of the scenarios that we've talked about that storage might be a need in the future.

But I guess I can let the PUC know that there won't be any requests for ratepayer funds to build new storage down there in the next 30 years. So, that's what I heard and I guess they'll be happy about that, too.

But in any case, I'm sure public comment will get into more detail about why that's the case, and any other issues for the forecast that we -- that Ivin and his team want to know about, or need to know about to do the forecast.

And, really, just to keep the Commission fully informed about what the upcoming scenarios might look like, and what the different perspective scenarios are going forward.

And that’s not just for this portion, you know, just going forward for the next 5, 10, 15, and beyond years.

Let’s see, so, yeah, I’ll just invite those written comments. You know, more is better. I know that sometimes today -- today seemed relatively formulaic, there weren’t that many comments, but sort of in real time. But, you know, I hope that’s because people are really giving it some thought to work with the Commission and hold hands to provide substantive comments, because I know that they get used and it’s very valued and valuable for us.

So, with that I’ll thank Ivin and the IEPR team, Suzanne and her team, and pass it back to Ivin for a close out.

MR. RHYNE: All right, thank you, Commissioner.

I do want to close with just one last thought and admonition. The world that we inhabit today is one in which the energy markets and the energy sectors are far more interconnected and interdependent than they ever have been in the past.

The path towards higher renewables will bring the gas sector into closer alignment with the electric sector. The push towards electric and natural gas-powered vehicles will do the same thing.

And so, all of the worlds that we have historically considered to be separate are becoming more interdependent and so, as we move forward in the 2013 IEPR, we are working hard to identify some of those interdependencies and understand at least some of the initial implications of what those interdependencies mean.

But it really depends largely not on our expertise, but on your participation.

And so, my admonition is this, if you have thoughts that occurred to you, if you have specific numbers, values, references, pieces of information that you think are of relevance to us, please don’t assume that we know of them.

We do our best to stay informed and we actually spend a great deal of our time and energy monitoring what goes on out in the industry.

But, as I think all of you may already know, it is a very large industry to keep track of. And so, there are always new ideas, there are always new pieces of information out there.

And so, especially if they have relevance to any of the scenarios or perhaps think of them as narratives that we've shared here today, or the issues that underlie those narratives, please share those in the comments.

And we have comments are due by May 8th of this year. You can submit them via e-mail. We actually encourage you to submit them via e-mail. And the docket number is 13-IEP-1K, as in kilo, and then indicate the natural gas modeling and trends in the subject line, and it's docket, that's singular -- docket@energy.ca.gov. Again, that's docket@energy.ca.gov.

Or if you feel like you want to make sure it gets there in a more perhaps hardy fashion, a little old-fashioned, there is a physical address. You could mail it to the California Energy Commission Dockets Office, which is at mail stop number 4.

This information is included in the workshop notice, as well as this presentation and all the presentations that were shared today will be posted online either later today, or first thing tomorrow.

As I close, I really want to thank everyone, all of our participants who are here from the industry, for sharing their points of view and their expertise. Thank you very much, it is very much appreciated.

I also want to extend a special thank you to those who were part of the audience, who listened and participated. Thank you very much.

And, finally, it is always a pleasure as a manager to have a team of people who you can rely on to get things done and the three staff members, Leon Brathwaite, Robert Kennedy, Peter Puglia, and they really did the lion's share of the work in putting this together. And I want to thank them, personally, for their hard work and their making sure that this came together as well as it did.

So with that, we will close out our workshop today. Thank you all very much. Please drive safely and, hopefully, we'll see you and hear from you soon.

(Thereupon, the Workshop was adjourned at 3:25 p.m.)

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