BEFORE THE
CALIFORNIA ENERGY COMMISSION

In the matter of Staff Workshop on)
Natural Gas Market Assessment,)
Reference Case, Proposed Scenarios)
and San Bruno Incident Safety and)
Reliability Implications)

Docket No. 11-IEP-1K

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Reported by:
Kent Odell

Staff Present:

Presenters

Ruben Tavares
Peter Puglia
Leon Brathwaite
Paul Deaver
Robert Kennedy
Ross Miller
Matt Layton
Ivin Rhyne

Dr. Ken Medlock, Baker Institute at Rice University
Catherine (Katie) Elder, Aspen Environmental

Also Present

Timothy Tutt, Sacramento Municipal Utility District
Dan Kirschner, Northwest Gas Association
Dan Patry, Pacific Gas & Electric Company
Les Bamburg, Sempra LNG

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P R O C E E D I N G S

APRIL 19, 2011 9:12 A.M.

MR. TAVARES: Good morning. I think we're going to start the workshop. Good morning, everyone. My name is Ruben Tavares, I'm part of the staff at the Energy Commission. Welcome to today's staff workshop on Natural Gas Market Assessment, Reference Case, Proposed Scenarios and San Bruno Incident Safety and Reliability Implications.

This workshop is being conducted as part of the Energy Commission's Integrated Energy Policy Report proceeding. It is a staff workshop. For those of you who may not have been here at the Commission before, the restrooms are in the atrium, out the double doors and to your left. We have a snack room on the second floor at the top of the atrium under the white awning. If there is an emergency and we need to evacuate the building, please follow the staff outside to the Roosevelt Park, which is diagonal to the building, and please wait there until it is safe to return.

Today's workshop is being broadcast through our WebEx Conferencing System. Parties need to be aware that it is being recorded. We will make an audio recording available on our website a few days after the workshop. A written transcript will be posted on our website in about two weeks. For those of you in the room who wish to speak, there will be public comment period after staff and consultants make their presentations this afternoon. In addition, there will be an opportunity to raise questions after each and every presentation that we have today. Please, how can I ask you, when you want to ask questions or make comments, use the microphone at the center, just by that chair in front of the staff, they will be making the presentations, so the people on WebEx can hear you. It is also helpful if you can give the Transcriber your business card when you come up to speak so that we can make sure your name and affiliation are reflected correctly in the transcript.

For WebEx participants, you can use either the chat or raise hand functions to let our WebEx coordinator know that you have a question or a comment. For those participating only by phone, and not to the WebEx system, we will open the lines at the end of each presentation and open the public comment period to give you an opportunity to speak and ask questions. We will be accepting, also, written comments on today’s topic until close of business, May 3rd, in other words, next month.

The notice for today’s workshop, which is available on the table in the foyer is also available on our website, and it explains the process for submitting written comments to the IEPR Docket.

Today's staff workshop focuses on Natural Gas issues. Each and every issue presented to you is presented to you for comments and suggestions. This morning, staff will address trends related to demand of natural gas, supply, pricing, and infrastructure issues. After the staff makes presentation, Dr. Ken Medlock will be presenting the reference case. He also will be presenting modifications he made to the reference case, to make it the preliminary reference case. So, what we present today is a preliminary reference case, again, for comments and suggestions.

We have not yet completed our evaluation; it is still in the process. We are showing the reference case, again, to get input and possibly make changes to create useful alternative cases. We probably will have a break around noon time for luncheon, and this afternoon after Dr. Medlock's presentation on the reference case, Ross Miller from the staff will propose some possible modeling scenarios to the reference case. Again, I will emphasize that those are presented for you to provide comments to us.

After Ross, Katie Elder, our consultant, will present general environmental concerns with natural gas and will also address the Commission's intention to address some of the safety and reliability concerns regarding the pipeline system.

Finally, this afternoon, Matt Layton from staff will talk about the localized risk concerns the Energy Commission has from interconnection of new power plants to the gas system.

We also have scheduled another workshop on natural gas issues for July 25th. At that time, we will present our Natural Gas Market Assessment Report with results from staff's reference case that will include your comments, the scenarios, and also our own input on some safety and reliability concerns we have on the state pipeline system.

Are there any questions before we start with the presentations? Okay, you can see the agenda, it is on the screen. Our first speaker is Peter Puglia from staff. He's going to be presenting current trends on the demand side. Okay, Peter.

MR. PUGLIA: Good morning, I'm Peter Puglia and I'm the Natural Gas Demand Analyst in the Analysis Office. My presentation is designed this morning to offer a structured and a simple briefing on an important topic to policy makers and other stakeholders who are buried in an avalanche of important topics. We would like you to keep in mind today that the demand for nature gas interacts with supply, with prices, with production from wells, processing, pipeline, and other infrastructure. These are going to be dealt with in subsequent presentations; what I'd like you to remember, though, is that each of us are adding pieces to a single puzzle that completes a picture where natural gas fits in everyday life. The wild card in the United States in California is the electric power sector, so I singled that out at the bottom of this slide. The reason is because natural gas-fired power plants account for a large and increasing share of natural gas demand. And the electric power sector has been, and will most likely remain, a big target for environmental policy.

Those of you who have seen previous presentations I've done, I'd like to remind you that my comments on these slides are inductive, I try to let the data speak for themselves. I've often written drafts here at the Commission and find out later about data that invalidates whatever I try to say, I don't want to be embarrassed, and I don't want my boss to be embarrassed, so I try to just stick with the most plausible interpretations of the data.

The North America Natural Gas Pipeline Network integrates the United States, Canada and Mexico, but as you can see from these numbers here, the United States is the 800-pound gorilla that has 82 percent of the Continent’s demand. Leon is going to go into a lot more depth about the supply picture, and Robert is going to deal with infrastructure, he’s going to lay that out in detail so you can see that in fuller scale for yourselves in their presentations.

All but about eight percent of U.S. natural gas is used in the four major demand sectors, residential, commercial, industrial, and electric power sectors. These four terms are universal terms in the economic literature that categorize the homes, residential, public and private business, commercial, manufacturers, that’s the industrial sector, and the electric power sector, those are the natural gas-fired power plants I just referred to. They account for almost all of North America natural gas consumption except for that eight percent that’s used in actual production of gas. Consumption and demand are synonyms in the economic literature. In 2009, the residential sector consumed 21 percent of the year’s total of 22.8 trillion cubic feet of natural gas in the commercial sector, consumed 14 percent, industrial sector 27 percent, and the electric power sector, 30 percent.

The factors I’m including here on the slide are the key elements of my presentation. I’m going to refer to them again at the end, I'd just like you to keep them in mind, they are the factors that account in both historical modeling and in forecast modeling for each of these sector's demand. There is a lot of debate, and a lot of you know this, among economists about other factors that might do a more accurate job of this accounting, our Demand Office has some of them solved, but they tend to pile in on the same sets of numbers, otherwise nobody would use them. And these are the factors that we use in our own Rice World Gas Trade Model, which Dr. Medlock will be talking about later, and which we use in our Market Builder modeling.

Over the past decade, there are significant trends in natural gas demand, I've just given you six bullets here, just some summary of the biggest ones, and the question when you look at these, each of these bullets, you might be asking yourself is why are we seeing these trends. And why I like my job is that you can never be sure what the answer is, but you can probably be sure you're in the right ballpark and I'll still get paid anyway. The factors I just discussed on the previous slide I'm now going to address in detail to help you answer the question why we are seeing these.

Weather – you notice in the residential and commercial sectors on the previous slide, weather is the most important factor, and you can see here in the residential and commercial sectors the seasonal variation over the last five years of data that I've charted here. You'll see that, in the winter, you have natural gas peaking in its consumption and it's simply – this is intuitive, this is simply homes and businesses that get cold and people are going to ramp up their furnaces or other natural gas-fired equipment to heat those residential and commercial spaces, it's as simple as that. Now, I'm adding the industrial sector, and in the industrial sector, weather isn't the most important factor, it's charted in green up here. There is a bit of a seasonal component you'll see in the winters that there is a bit of a peak, but most of the consumption below that curve is accounted by other factors, and intuitively, again, I think all of you are fairly educated, that would be industrial production, GDP demand for industrial goods, for manufactured goods.

And finally, our wild card, the electric power sector, you'll notice that, just like the residential and commercial sectors, it also has a seasonal peak, but unlike residential and commercial sectors that peak in the winter, the electric power sector peaks in the summers and that's because that's when air-conditioners ramp up to provide air-conditioning demand. Again, it's a weather factor that is a major driver of the electric power sector demand.

Now you’ve seen the seasonal effect of the weather, I’m going to give you if you’re not familiar with this, the quantitative measure of comfort that accounts for natural gas demand, and what you’re looking at here are cooling degree days which the national oceanic and atmospheric administration compiles. This is really, it’s population weighted, this is a measure of what does it take as far as a cooling degree day goes, what does it take for a certain population of people to cool them to a temperature where they’re comfortable again? And the standard temperature, I think it’s 68 degrees Fahrenheit, so the more people you have, the more cooling degree days there are, and you’ll see heating degree days on the next slide, it’s the same kind of methodology, what does it take to heat people up from a low temperature – the farther the temperature is down, and the more people there are, the more heating degree days there are, and the same thing with cooling degree days. And what’s interesting about this is if you look at California’s cooling degree days trend, it rises significantly. The U.S. trend is flat. Okay? Over the past decade, California’s cooling degree days have gone up not because it’s just a lot hotter in the state, but because a lot more people over the last decade have moved into the hot inland valleys and the deserts.

As I say, this is the record of heating degree days and, in both cases, the U.S. and California, they’re flat. On the previous slide, I want to point out, it isn’t a change in the weather because the U.S. data is flat, that’s why I’m telling you it isn’t a change in the weather, it’s the change in population, so I neglected to mention that on the previous slide, otherwise, the U.S. trend would probably be up, too, if it were a weather factor, but it’s just population migration that explains this.

We see the same thing for heating degree days, both California and the U.S. are flat. So, that’s the empirical measure that’s used, that most closely quantifies the weather factor in natural gas demand accounting. And here you can see for yourself, it’s a bit serendipitous that the cold parts of the United States, Census Regions, the Midwest and the Northeast I put down as black and blue, and you’ll notice that over the previous century, population growth has gone a lot flatter in those areas where in the south and west, population rates, growth rates, accelerated. People are moving into the warmer areas of the United States and away from the cooler areas.

Okay, so having exhausted weather, we go into another major factor in Natural Gas Demand, which is income. And the measure that I'm giving you here is personal income, and this is from the U.S. Bureau of Economic Analysis and this may not look significant, but the increase in income between 2000 and 2008 is not too far short of 50 percent, so you know, in looking back at slide 5, and you're asking yourself, "How come there's been decreasing demand in every sector except electric power for natural gas, when income has gone up this much?" Well, you know, there are a battery of reasons for that, one of them could be that energy efficiency programs have been more successful with increasing natural gas prices, which I'll show you on the next slide; increasing natural gas prices would motivate people to make investments in energy efficiency technologies for their houses, for their appliances, or just their habits. So, that could be one explanation. Another explanation is that a lot of Americans didn't participate in this income growth, there is a ton of evidence that suggests that. The money was there, the income increased, but people aren't using it to buy natural gas. Maybe they've got the money, they're just not going to spend it. The question is how comfortable do you really want to be and how comfortable do you need to be? So, there is a possibility that this income growth, if you divide it out amongst deciles or quintiles amongst Americans, you'll find that a lot of Americans didn't get any of this. So, that's one possible explanation.

Now, this is California natural gas prices, I'd like you to just sort of blow off that spike there in 2000-2001, because you kind of know what happened then if you had anything to do with the electricity markets restructuring program here in California, that's the other – Canada and the rest of the United States don't show a similar price change. Paul is going to go into more detail about prices and is going to explain the factors that influence that. What I'm trying to draw your attention to is consistent patterns here that you do see elsewhere in the United States, Canada, and Mexico, which is residential natural gas is usually the most expensive, then followed by commercial, industrial, and electric power is the cheapest. And Paul might explain to you why that's the case, but I don't have enough time to do it, I can explain to you later if you need that. And also, the general price trend up until 2008, which is true for most commodities, was up. Now, this is a possible explanation for following natural gas consumption, but what I would like to point out to you is that a dollar in 2000 bought what $1.25 buys today, so there has been inflation over that decade, and that's the Bureau of Labor Statistics Urban Consumer Price Index change, there are others, but that accounts for some of it, it doesn't account for all of it, the decrease in demand amongst most Americans.

Okay, and like I told you at the beginning, electricity, that sector, is the wild card and it's a wild card because it is subject to a lot, it's a convenient target, it's not spread out all over the country in a number of very small establishments. Power plants are multi-billion dollar, easily identifiable sources of energy, and they also are a source of a lot of emissions and their role in supporting the electric grid is really publicly a huge priority, we saw that in 2000-2001. So, there are a number of programs that target the electric power sector that have influenced demand for natural gas and, as I hinted before, can be expected to continue doing that. Like I mentioned, energy efficiency, those programs, my take on this, the benefit of looking at the data is that it tends to reduce natural gas and electricity demand.

Another policy measure that's directed towards electric power sector is demand response, which is designed specifically to reduce peak megawatts, okay, it's just to reduce the need to invest in further combustion turbines or other peaking sources to provide for load during really hot days. Okay, the third one is – this one is coming up, this is not an influence on past trends, but it is coming up in anticipation of this measure, certainly the 20 percent measure that's already in law. We have a 33 percent renewable standard now for electricity sales. That is probably going to increase natural gas demand because we're going to, in pursuit of resource adequacy and electric grid support, the sources of easily dispatchable electricity that are going to be most favored are turning out to be combined cycle gas turbines and combustion turbines, they just have the characteristics that currently would support the 33 percent build-out in providing for a net short that intermittent resources like windmills or solar plants, when they are not available, these things can be dispatched.

Climate change, which is AB 32, which the regulations are still being developed, so there is – again, I'm being a bit speculative here, so we don't have an actual set of measures to implement the 33 percent or the AB 32 climate change statute, we might expect similar things, trends, that natural gas demand is going to increase electricity, it's uncertain where that demand is going to go. And then, once-through cooling, that's before the State Water Board, and that targets steam turbines, most of them, down in the South Coast, that will be replaced by some combination of natural gas-fired electricity resources, renewable resources, it's not anywhere at the point where there are even proposals for projects to replace those steam turbines, and that might reduce natural gas demand, we don't know. So, these are forward looking measures, much of them, except for energy efficiency, that is forward looking, but also has a history that we are going to be treating in the future workshop, in our future work, in modeling scenarios that look at how these particular policies might change the business as usual, for lack of a better term, picture that Dr. Medlock is going to be sharing with us on natural gas in the United States and the rest of the world. You can see the differences in how that picture will respond to these policy levers vs. Dr. Medlock's base case.

So, again, in summary, these are the factors that our modeling uses, these are the factors that have accounted accurately for natural gas demand, and I hope I've given you a set of data and some explanations that put some meat on the bones of these factors and help you to characterize and also predict for yourself where natural gas demand will go for each of these four sectors. Thank you.

MR. TAVARES: Are there any questions on the Demand side for Peter? Anybody on the phone on the WebEx? No? Okay, let's continue with Leon. Thank you, Peter. Okay, Leon is going to present the supply side of the picture.

MR. BRATHWAITE: Thank you, Ruben. Good morning. I'm Leon Brathwaite. I'm going to talk about the current trends on natural gas supply. Peter was absolutely right a little while ago when he said that we are all presenting pieces of a puzzle here because, of course, we don't have demand without supply, we don't have supply without demand, and we've got to have things to connect them which is the infrastructure, which other people are going to talk about, and all of that is manifested in prices, which another one of my colleagues will address here shortly.

So, we're going to be talking here about natural gas supply. The one thing that has to be said, that basically on the supply side of the natural gas industry these days, the story, really, is about the development of the shales, and you will see that as I go through my presentation.

So, the first current trend we have here is total lower 48 natural gas production is rising. If you look here, at the schematic here, you will see that you can see that, from starting around 1995, going forward, production was relatively flat. We did have a dip-off here that bottomed out in 2005, but since then production in the lower 48 has been rising. This portion appeared, that brown area above there, that is our shale production and what you can take away from this graph is that, had it not been for shale development, overall production would have been declining, which would be the top of the blue. So, that’s a very interesting thing that we will see more of as we go along here.

Second trend, total production from shale formation, is surging. Again, from 1995 to about 1998, it is fair to say that shale production was negligible. I mean, it’s barely visible on the schematic here. Starting around 1998, right around here, we saw a slow but steady increase in shale production, but around 1995, production just took off. Right now, I think shale production is running about 16 BCF a day, I mean, you’re talking about a tremendous amount of gas, and by most counts, we have only scratched the surface.

Next trend, shale formations are contributing an increasing share of the lower 48 production. If you look here, this is the brown portion right above here, that is shale, that is the contribution that shale is making to lower 48 production. So, in 2000, shale formations contributed about two percent of the total natural gas production in the lower 48. By 2010, last year, shale was contributing about 23 percent. And, in a little while, we'll hear from Dr. Medlock, Dr. Ken Medlock from Rice University, and he's going to give us an idea of the way he sees shale production is going over the next 10, 20, or 30 years, that will be quite interesting.

Next trend – total reserve in the lower 48 are increasing. The schematic on your left is proved reserves, and when I saw "proved reserves," I'm talking about reserves that are developed, that are producing, some of them are what we call our "behind pipe." These are resources that are geologically known developed and producible with current technology. The schematic on your right is potential reserves, these are natural gas resources that we call probable, possible, or speculative. These resources are geologically known with decreasing levels of certainty. They are undeveloped, but they are producible with current technology. So, what's been going on? Between 1999 and 2009, proved reserves went from 150 TCF to 260 TCF. Now, you must keep in mind that, during that time period, for every year in that time period, we were producing about 20 TCF in the lower 48, almost 20 TCF, somewhere around there. But, yet, proved reserves are rising. The potential reserves, and when I use the word “potential reserves,” I’m talking about those things that, like I said, that are geologically known with decreasing levels of certainty. That also has been increasing going from about 950 in 2000 to about over 2000 TCF in 2009. In AEO 2011, technically recoverable reserve, that is, proved possible potential for the shales, was 827. For all natural gas resources, it was 2,552. And if you’re wondering how much gas that is, our current rates of consumption, that is enough gas to last us for 115 years, so we’ve got a lot of gas, lots of it, tons of it.

Next trend. Current technology is transforming the natural gas industry. Shale formation stretched to at least 23 states, at least 23 states, there may be more, okay? These formations contain vast quantities of natural gas. Now, on this particular schematic, you will notice that in California, there is nothing represented, okay, there is no shale identified at least on this graph, but there are two formations in California that are potentially producible, that is the McClure and the Monterey shales. We had originally thought that these shales were not producing, but just recently, Occidental reported that they are producing from the shales. I don’t remember how much gas it is, but it’s not a lot of gas, but it is certainly being produced right now. So, what is happening right now is that technology is giving us access to those shales. During previous times, we would drill through the shales, we would seal them up, you never hear anything about them ever every again; but right now, with hydraulic drilling, with horizontal drilling, hydraulic fracturing, we have complete access of those shales and the shales are really transforming the way we produce gas, the way we consume it in some cases.

Okay, continuing with the technology transformation, technology have impacted all stages of natural gas development, exploration, drilling, completion, including hydraulic fracturing, and production. And when I use the word “completion,” I’m not talking about the end of a process, okay? I am talking about that process between the end of drilling and the first production. During that period, we may have our hydraulic fracturing being done, we may have the proliferation of the wells, we may have clean-up and all these sort of things that occur, that is what “completion” is, it is not the end of anything, it is a process, at which we bring a well onto production.

So, technological innovations have occurred in exploration. What has happened is that 3-D and 4-D seismic has enhanced the capability to delineate the limits of the deposits. As a result of that, exploration has successively gone from 30 percent in the 1990’s to about 65 percent in the late 2000’s. We also have technological innovations in drilling, overall drilling success has reached 90 percent, now, that is phenomenal when you really think about it. And horizontal drilling has increased wellbore exposure, and I will show you this in the next schematic, by a factor of 5 to 25 percent. Well, my graph says 20 percent, so let me stick with that.

So, this is what I’m talking about with wellbore exposure. In a traditional vertical well, what will happen is that the driller will come down here and drill to – this is all formation of interests, it is the Marcellus in this particular case, in a vertical well, the driller will just drill through that formation and will complete the well in this area here, so the wellbore exposure in this area -- inside oil well here is a wellbore, the wellbore exposure will just be the vertical distance here of the thickness of that formation, the Marcellus in this case. What has happened with horizontal drilling is that we have not been able to increase the exposure by going almost horizontal within the formation, so instead of having just this thickness here available to you, the producers now have this much, and this may be five times as much, 20 times as much, it just depends on how far out they are willing to go. So, what has happened is that we are able now to do multi-stage fracture jobs, or hydraulic fracturing jobs. In this particular case, we have seven different stages. And these stages can run as high as 12, maybe even more. So what happened with hydraulic fracturing is that we create this artificial network of fractures, they are sun perpendicular, so that the fractures can remain open and this has significantly boosted production and also boosted recovery rates. So, what hydraulic fracturing and horizontal drilling have done, they have totally transformed the industry so that we are now having better recoveries and better production from oil wells. And these are wells that were not even producing 20-30 years ago.

Okay, technology is also shifting the marginal cost profile. The blue line on this schematic is our 2007 marginal cost profile, the red line is our 2011, the current one. If we look here at 800, just as an example, if we look here at 800 TCF, that would be available on our blue line at about $6.00 or so per MCFe, but if you look at it on the red line, which is our 2011 line, that is available below – below -- $4.00. So, the net effect of technology, really and truly, is to make more resources available at a lower cost.

Next trend. In keeping with the previous slide, finding and development costs, finding and development costs are declining. Now, the blue line here is a recount, and when I'm talking about a "recount," I'm talking about a weekly census of the number of active drilling wells exploring for natural gas in the United States, okay? That's what I'm talking about, a recount. There is another metric that people look at sometimes, which is the number of wells that are currently producing, that is not what we're talking about here, and I'm just talking about the wells that are actively drilling. So, if we look here, the purple line is Henry Hub prices and that is read off of your right scale, the blue line is a recount -- the total natural gas recount -- the green line is the horizontal well recount. Now, I think it is fair to say that, in general, the recount and prices have increased together, I think you can fairly say that, I mean, you cannot say there is an exact 1:1 correlation, but I think it's fair to say they have increased together. But, around 2008, prices collapsed and so did the recount, right there. Now, notice that we have had some recovery under total recount, but it has not gotten back to its pre-collapse level, as yet. What has happened with the horizontal wells, with our primarily used in the shales? We did have a little bit of a dip when prices collapsed in 2008, but the recount has just kept on going, kept on increasing, stayed strong, and we are now seeing some leveling out, out here, but notice that it has certainly exceeded the level prior to the collapse of prices in 2008. So, FERC was looking at this information and using their terminology, FERC says shale gas development has turned the economics of drilling for gas on its head. New technology have pushed productivity to new heights, we are now measuring drill times in days, rather than weeks. And this reduced drill time has pushed break-even costs to less than $4.00 MMBtu, now, that's a stunning thing when you think about it. Next slide.

Natural gas liquids are boosting economic feasibility. Now, I think you all know that a chemical composition of methane, which is a primary component of natural gas, is CH_4. And natural gas liquids are the heaviest stuff, those are the propanes, ethanes, and butanes. And in the presence of these natural gas liquids, economic feasibility has really been significantly improved and EIA's data is beginning to show this. If you look at an average between 2006 and

2008, finding and development cost was running almost $5.00, but if you look between 2007 and 2009, finding and developing costs for MCFe is running below $4.00, so you can see the significance of natural gas liquids and the overall impact of technology on the finding and development costs in the natural gas industry. Next slide.

Continuing with natural gas liquids are boosting economic feasibility, gas produces a shift in the exploration and development dollars to liquid rich properties, drawing ventures with foreign entities are becoming quite popular these days, in particular, the Chinese, and where are these liquid rich formations? The liquid rich formations include the liquid corridor of the Marcellus, that is the southern and the western portion of the Marcellus, the Bakken and North Dakota and Montana, the Niobara in Nebraska, Wyoming and Colorado, the Eagle Ford in South Texas, which is now producing 40,000 barrels of oil and natural gas liquids, and the Tuscaloosa Marine shale in Texas, Louisiana, and Mississippi.

Shale potential is also changing the industry in other countries. Canada, or neighbor to the north, is developing several formations, the Horton Bluff, the Utica, the Lorraine in East Canada, the Muskwa shale, and the Horn River in Northeast British Columbia, the Montney and the Bakken shale in the Western Canadian Sedimentary Basin. Production right now is running about a BCF or 1,000 million cubic feet a day from the shales. The estimated technically recoverable shales – and remember, that is proven potential for the shales – in Canada is about 380 TcF. In Mexico, Mexico just tested its first shale well and that well produced about 3 million a day, that's a significant amount of gas from one particular well, estimated technical recovery resources in Mexico is 681 TcF. Now, the Eagle Ford shale, which is in South Texas, here in the United States, but that shale extends into Mexico, so in Northern Mexico, that is where PMEX, the state owned company, just went and drilled their first well and got this pretty successful well.

Poland is beginning development drilling its first well. Estimated technical recovery resources look about 187 TcF. Sweden has identified several shale formations, they have about 41 TcF of potentially recoverable. China has a vast amount of natural gas resources in their formations and is beginning exploration. Estimated technically recoverable resources there looks like about 1,275 TcF. Worldwide, estimated technically recoverable resources look like over 6,600 TcF, that's phenomenal.

Now, I just want to say one thing, okay? The development of the shales have some very profound and serious geopolitical consequences that are way outside the scope of my presentation. I mean, some very simple – very simple – questions will come up as shale is more developed. For example, what would happen in the relationship between Russia and Europe if Europe develops its own shale potentials? What would happen then to that relationship? There are geopolitical consequences here that we probably need a whole workshop to discuss about development of shales.

The last trend that I will discuss here today is that shale environmental concerns are creating uncertainty. The first environmental concern, obviously, is greenhouse gas emissions, methane, the primarily component of natural gas, contributes to GHG emissions, and at consumption, it produces about 117 pounds BtF of Carbon Dioxide. Surface disturbance is another potential problem. Every time you go to drill a well, we have to clear the surface, and that has created environmental stresses in some sensitive areas. This, of course, has led to some moratoriums, for instance, in the Rockies, in the watershed areas, in New York, this has limited the development of the Marcellus, at least on the New York side of the Marcellus. Pennsylvania is currently developing their portion of the Marcellus shale, New York is not.

Fresh water usage is a potential problem. Every hydraulic fracturing job requires somewhere between 2-4 million gallons of fresh water, and this may avert fresh water from other important and essential uses. The disposal of retrieved water, after completion of one of these hydraulic fractured treatments, it produces normally – retrieves about 30 to 70 percent of the water that was originally injected. Now, the disposal of that water may present some environmental concerns such as spillage, potentially ground water contamination, these are all issues that are of some concern. Increased seismic activity, the ongoing studies examine possible links between oil and gas operations and increased seismic activity, in particular, right now, I mean, Arkansas, in relation to drilling that is ongoing in the Fayetteville, there is a professor at one of the universities there that is looking into the relationship, if there is one.

Groundwater contamination, now, this subject has been the source of a great amount of controversy and I'm not here to tell you that I have definitive answers, I don't. However, ongoing studies are trying to quantify the risk that is associated with hydraulic fracturing, in particular, and the government agencies that are involved with this are the Environmental Protection Agency at the Federal level, several State agencies, the Secretary of Energy Advisory Board under the Obama Administration, they are all looking into this at this point in time. Now, I think it is fair to say that nearly all oil and gas operation does present some risk to the groundwater aquifers. The unanswered question, of course, is how much, this is what we don't know, and these studies hopefully will illuminate the associated risk.

Now, the Groundwater Protection Council, which is a national association of State agencies that are concerned with maintaining safe drinking water, has a website, and they have quite a lot of information about this matter on their website, and I would encourage you to go there and see what they have to say about this. Like I said, it's a very controversial matter and there are no definitive answers at this point in time.

This takes me to the end of my presentation, and I'll be happy to take any questions or comments that you may have. Thank you very much.

MR. TAVARES: Thank you, Leon. Any comments or questions? No? If you could go to the microphone there? There's a question or a comment?

MR. TUTT: I had a quick question. I'm Tim Tutt from Sacramento Municipal Utility District. And the question was, the last part of Leon’s presentation, hi, Leon, talking about the environmental concerns and issues, has the staff done any estimates of how that will affect supply and price, and other scenarios related to that question coming up?

MR. BRATHWAITE: One of our scenarios, and Ross will be discussing this here in a little bit, one of our scenarios are going to look at what’s going to happen with increased environmental costs, and we will be putting that into our World Gas Trade Model and see what it does to flows and that kind of stuff, but there are a variety of scenarios that can be run, trying to deal with this very issue, Tim. You know, if we feel that there are certain areas that should be shut off, we can do so and see what effects that has on supply and demand and prices, but there will be at least one, maybe two, scenarios dealing with increasing environmental costs, or even to the point of having increased moratoriums on some of the shale supplies.

MR. TAVARES: Thank you. Any other questions, comments? Yeah, just to add a little bit more information, we are looking very carefully at the potential impacts and environmental concerns in regards to shale gas production. You know, hydraulic fracturing has become very controversial, so, yes, we are looking very carefully. And, as far as modeling is concerned, we are also soliciting any comments, questions, suggestions that you might have in regards to these scenarios. You will want to hear a little bit more about it as we have other presenters here today, so keep those in mind.

Thank you, Leon. Our next speaker is Paul Deaver. He’s going to be talking about pricing issues of natural gas. Paul?

MR. DEAVER: Thank you, Ruben. Good morning, everyone. My name is Paul Deaver, I’m in the Electricity Analysis Office and today I’m going to be talking to you about Natural Gas Price Trends.

All right, this graph here shows us roughly the last 10 years of daily Henry Hub spot prices, and what a spot price is, it’s a one-time open market transaction for a specific quantity of gas delivered to a specific location, in this case, it’s the Henry Hub. Now, natural gas is a heavily traded market and, as you can see in this graph here, this shows you the volatility inherent in these types of markets. Also, notice September 2005, the trading on the spot market was actually stopped on NYMEX due to wells being shut because of Hurricane Katrina. Today I’m going to be exploring some of these ups and downs, and the prices, I’m going to try to figure out what these underlying trends are and what may be driving them.

Before I move on here, you notice we see a couple of price breaks for both the winter of 2000 and 2001 and in early 2003, there is a cold winter and, as Peter explained, people like to stay warm and run their furnaces, so we saw higher demand then. In September of 2005, the Hurricane Katrina, as she shut some of the production in the Gulf Coast, and we saw prices go up then. In 2008, there's a lot of mixed opinions on this, and I'm going to revisit this a little bit later in the presentation. All right, basis differentials, what is a basis differential? This is going to be the difference in the daily spot prices at some regional hub vs. the price at the Henry Hub. Now, you often see the Henry Hub referenced, this is the location of Louisiana and it connects to many other pipelines and gathering systems, and it's often considered a national benchmark price. Now, if we see a large sustained basis persist over an amount of time, so, for example, if gas is either a lot cheaper or a lot more expensive than Henry Hub gas, this demonstrates an opportunity to construct a pipeline and make a profit by flowing gas. We generally see basis differentials occur because of bottlenecks and congestion. If there's a bottleneck, you may have a lot of gas in one area where it is competing with itself, and that might put downward pressure on prices. We just heard about shale in the last presentation and with all the shale coming online, we may see some of these basis differentials shift as more supply comes in to different areas.

All right, this chart here, it shows you kind of the effects of what happens with the basis differentials after the Rex Pipeline became fully operational in November of 2009, and the Rex pipeline flows gas eastward from Ohio, or from Colorado to Ohio. All right, so bars that are above the zero line here means the price is more expensive than Henry Hub, while bars below the line shows that the price is cheaper compared to Henry Hub. Now, looking at both the Cheyenne Hub and the Southern California border average price hub, these are both west of where the Henry Hub is, and we see after the pipeline got put in, you can see the basis differentials shrank coming up to this point here, they got slightly smaller, and that's because more gas was flowing east. If we look at the PG&E Citygate, the change in the basis differential isn't quite as large. One reason for this is PG&E, the Citygate Hub gets about half its gas from Canada, so it's somewhat insulated from the effects of the Rex Pipeline.

Now, the Algonquin Hub is in the New York Pennsylvania area, and that's east of where the Henry Hub is, and if we look up here, we can see maybe those basis differentials shrank a little bit, but we also see in the winter months that basis differential is rather large, and this is because, on the East Coast, there's a lot of cold weather, but the demand here sometimes is higher than what the pipelines can take in.

All right, how California utilities procure gas. Back in 2009, our staff did a White Paper on this, and we also had a workshop for the 2009 IEPR, there hasn't been a lot changing since then, we found that most gas comes from short-term monthly contracts, meaning less than one year. Some gas is purchased on the spot market, multi-month contracts, and also withdrawn from storage. Now, gas withdrawn from storage, we can view that as kind of a physical hedge against spot prices, so, for example, if spot prices are relatively expensive on one day, a utility might want to pull gas from storage instead of paying those higher spot prices. The California Public Utilities Commission has established gas cost incentive mechanisms and this allows California utilities to hedge against price volatility and recover their costs through rates. In January of 2010, the CPUC made a final decision which shifts some of these hedging costs from the ratepayer – some of those are now paid by the utility, so that's really the only change we've seen.

All right, speculation. First off, let me briefly describe speculation for you. The commodity Futures Trading Commission defines a commodity futures speculator as someone who does not trade for hedging or physical delivery, but purely to make a profit on successfully anticipating price movements. Now, is speculation a good thing or a bad thing? There's a lot of different opinions on this. Some may argue that it provides liquidity in the market, speculators would act as a counter-party for a price hedger, so they can take on that risk, and with all this liquidity in the market, when we say "price discovery," there's many buyers and sellers and this would mean that, through all these interactions in the market, that we'd discover a price that reflects supply and demand. There's also others who argue that speculation in the market can cause market bubbles and unwarranted price movements because of herd behavior. A known example of herd behavior would be a lot of traders trading on limited information, and the price being bid just based on the number of bids, and not reflecting supply and demand. That being said, also price spikes and market bubbles can be caused by supply-demand factors. If you remember the first graph I showed you, we saw that some of the cold winters caused the prices to rise.

Now, going back to the 2008 example, we saw investments in commodities increase from 2005 to 2008, that was in all commodities, not just energy commodities. There was also a cold winter in 2007 that led to lower storage levels in the spring-summer injection seasons, so it is really unclear what exactly caused the sharp rise in price in July of 2008.

All right, financial regulation. This is talking about financial regulation in commodity markets and, I mean, there are many different commodities out there, but I want to focus on energy commodities and, in particular, natural gas. So, the purpose of financial regulation in commodity markets is to protect market participants against price manipulation, any type of market manipulation, or other fraudulent actions. You want to keep the markets efficient and keep integrity in the market. Also, we talked about price discovery a few slides ago, regulation should protect the price discovery function that the market serves, so that prices reflect supply and demand.

Recently, in July of 2010, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, or commonly referred to as the Dodd-Frank Act. Now, this Act has tasked the Commodity Futures Trading Commission, they're currently proposing regulations right now on many other commodities, but once again, I'm going to focus on natural gas and energy commodities, so two things that I thought were important in looking at energy commodities, this act is going to make the Commodity Futures Trading Commission, they're currently adopting position limits for exempt commodities, energy being an exempt commodity, and currently we have what is called accountability levels with some of the trading platforms, and that's kind of self-imposed position limits, if you will. So, basically what this is going to do, it's going to broaden what's covered under this, so, for example, we're going to have because of this act, aggregate position limits across trading platforms, so if you have a natural gas contract on, let's say, both the New York Mercantile Exchange and Intercontinental Exchange, there's going to be an aggregate limit of what one person or one entity can hold. Also of importance is there is going to be more data collection publication. Currently, some of this is going on right now, but what this does, it's going to broaden that and start covering more marks that haven't been covered previously.

All right, now some of the potential effects of this regulation. Well, first off, it may protect market participants against market manipulation, price volatility, despite deterring some of this action, I mean, everyone is going to know that these markets are being more regulated now, so that may stop some of that. Also, with the data collection and publication, this may increase market transparency and market surveillance by the regulators, but the public is going to be more able to see the data now, there’s going to be reports out. Also, something that could happen is market liquidity may be reduced. This may cause the markets to become less efficient and this may also increase cost to investors and ratepayers. An example of this, there may be an investor in the market, a price hedger, that may be more reluctant now to make these trades if there’s an increased cost of this regulation, and there are less trades being made, that information is not going to be reflected in the price.

All right, the oil-gas relationship. This is the – we often see crude oil and natural gas trending together over time, I’m going to be showing you a graph of this on my next slide, as well. Some of the basic reasons for this, crude oil and natural gas have generally the same geology underground, the similar technologies to be extracted from the ground, the same exploration and production cost structure, many big energy companies, they will produce both oil and natural gas. There are also substitutes through fuel switching in most world markets. Now, the U.S. used to do this, but fuel switching with natural gas and residual fuel oil, but that's not so much the case anymore because of environmental regulations in the 1990's. Also, natural gas is used as an input fuel for enhanced oil recovery operations. So, this kind of gives you a sense of why these two fuels might move together, the price of them. This link has appeared to have gone away since the end of 2008, and staff here at the Commission addressed this both in the 2007 and the 2009 IEPR.

All right, the graph. So, the prices here, these are weakly average spot prices from the EIA website. And as we can see over about the last 10 years, we see that these prices do follow each other, even though this relationship isn't perfect, there's a couple times there we see the Henry Hub national gas get a little bit higher – before I forget, the crude oil here is West Texas Intermediate or WTI – now, if you look around at the beginning of 2006, we can see after this, you can really see that relationship start to stand out – it looks like this line got pushed back – and in the beginning of 2009, this line should actually be right over here, we see that relationship kind of fall apart and, coincidentally, this happens kind of at that low point of that oil price, and since then we've seen natural gas either steadily staying flat or decreasing, and we've seen crude oil prices increasing, so that's kind of why we see that divergence there.

All right, this graph shows the last 10 years of the oil gas price ratio and what this is, once again, this is weekly data and I'm basically just taking the numbers from the last two graphs, the price of West Texas Intermediate divided by the price of Henry Hub gas. Now, you see thermal parity on here, and let me describe this quickly. Now, we generally have six MMBtu, or a million British thermal units, in one barrel of crude oil, so if these two prices were priced strictly on energy or heat content, we'd expect to see crude oil be about six times more expensive than natural gas, so we'd want to see this ratio be 6:1 in that case. And this red dash line here illustrates that.

Another thing you notice from this graph is the thermal parity which is 6 here, 6:1, this doesn't happen too often, and if you look at the average from about 2000 to 2006, the average of this ratio is about 7.5, so it's actually a little bit higher. And the last time we actually saw this ratio at 6:1 was the beginning of 2009, and this is also when we started to see the oil gas price relationship diverge. And since then, we can see how this has been going up and, as I explained before, we have seen crude oil prices increasing and we’ve seen natural gas prices either flat or decreasing in the $3.00 to $5.00 per MMBtu range.

All right, delivered cost. Up to now, we’ve been talking about the commodity cost of gas, or the physical commodity itself, now, the delivered cost is going to be the cost of that gas plus the cost of transportation taking it to the end user. We see some differences among customer classes, Peter earlier talked about the residential, industrial, and the other classes for demand, but generally these are the interstate pipeline rates, but they’re more stable than the commodity prices. You may see them increase maybe by a small percentage each year, they’re not going to have the same amount of volatility that the commodity market does. Now, there are some new costs that might change what we pay for delivered gas, the first one is gas displacement of coal; if more gas is used relative to coal, that would make demand go up and put upward pressure on prices. Also, the EPA came out with an Advance Notice of Rulemaking and they’re going to reassess the authorization for use of PCBs or polychlorinated biphenyls. Katie Elder is going to be talking about this in a little more detail in her presentation. Also, the reporting of lost and unaccounted for gas, which includes leaked gas and fugitive emissions and also GHG reporting, that may add a cost on, as well. And lastly, replacing old California pipelines and infrastructure, for that matter; as pipelines and infrastructure age, they eventually need to be replaced and we'll generally see these coming out in terms of rates, paid by the ratepayer.

All right, this is an illustrative example that basically shows how some of the transportation costs are added on from the wellhead going to the end user. So, the wellhead price here, this is an average price for February, once again, this is just illustrative, these aren't exact numbers. And this is on PG&E's system and the pipeline here, the interstate pipeline is El Paso. So we notice the wellhead price is $4.11 and one thing I noticed here is that there's only a $.2 difference between the wellhead price and the border price. These prices are set in two different markets, so a gas marketer buying gas at the wellhead who wants to sell it at the border, they still have to pay that interstate pipeline tariff. Now, once gas gets to the border, it can go on to the backbone system, the transmission system, and the distribution system. And the other thing to note here is that residential customers, they can repay the most for transportation and, in this example we see it’s more than half of the total cost of gas. The other thing to note here is that the distribution, part of this system is generally the most expensive for electric generation and industrial customers, they can also be backbone level and transmission level customers and, in that case, we would expect to see these transportation rates be a little bit less. All right, this graph shows just one day of trading on the New York Mercantile Exchange, this is just an arbitrary trading date to give you an idea of what goes on here. The first thing to notice, well, first of all, the Henry Hub price is the green line here, it’s on the left axis, still priced in dollars per MMBtu, and on the right axis, we have the number of contracts. So the first thing to note is that the number of trades drops off very quickly here. This shows you that there’s a lack of long-term liquidity here, and even out here, this line looks flat, but sometimes you’ll see maybe just a couple trades being made here and there, but it becomes very scant after about the first 24 months, there’s not too much trading going on.

The second thing to notice here is the price here steadily increasing and, if you remember from my first graph, the prices didn’t exactly look like this, and also these small little humps here, these show the winter demand, how more heating is used, and Peter discussed that earlier. We also remember from the first graph that these aren’t always going to be the same exact size, maybe they have one winter that’s colder than another winter, so that’s another thing to look at.

All right, blending forward prices into a fundamental forecast. I forgot to mention on the last slide that those Henry Hub prices are sometimes referred to as “Forward Prices,” so blending is a method where we would use the first few years of Forward Prices and then, thereafter, use a fundamental forecast. Now, there’s mixed opinions on whether to use this or not, and there’s the belief that no forecast performs well in the short run, so using futures will at least perform as well as any other forecast, and also that these Forward Prices, that they’ll provide a collective judgment of the market, people that trade in this market, that are involved in the market every day, and their information gets to be reflected in the prices, which reflects supply and demand. There’s also some potential issues of blending. We don’t know what assumptions were made by the traders, we don’t know if all the traders have the same assumptions, they may be trading, trying to fund supply demand trends, they may be trying to balance a portfolio, we don't know exactly what their underlying assumptions are on this. Also, we talked about the market having a lot of liquidity. A few slides back, I showed you the price of one trading day, these curves can change daily, always as new information gets added into the market and gets reflected in the prices.

If we look at the Forward Prices on a few slides back, we can see that generally wouldn't be a good forecast compared to the first slide I showed you, and you're just not going to encompass all that volatility in there. The volatility is really hard to predict. Once again, there's a lack of long-term liquidity as trades become very scant after about the first 24 months, there's not a lot of trades happening. And we also talked about herd behavior and accountability avoidance. We would like these forward prices to reflect supply demand fundamentals, but that may not always be the case. Currently, our staff is looking at this, we're going to examine this a little bit more and decide what is going to be our best path to proceed forward. And I believe that is it. I'll open it up to questions now.

MR. PUGLIA: Paul, could you go back to slide 15, please? It's Henry Hub Futures Day, yeah. I think this is really helpful, if you could explain this, you're looking at about summer of 2012, this is on March 11th, nobody bought a standard contract for gas from about late summer of 2012 on, to the end of the horizon. In spite of that, you have a projection for the Henry Hub price beyond that date. I was wondering if you might explain how anyone could come up with this Henry Hub price forecast beyond the summer of 2012 when no one has taken a position in natural gas beyond that date.

MR. DEAVER: All right, that’s a really good point, Peter. And I actually forgot to bring this up. So, when there’s very few trades being made, NYMEX will actually look at the spread between the asking price and the bidding price, and they’ll come up with like an estimated weighted average price, I don’t have the exact formula in front of me, but, yeah, I mean, you could still have a price and not have any trades made, there’s a calculation that’s done to get an estimated price based on the spread of the trades. With that, I’ll hand it back to Ruben.

MR. TAVARES: Any more questions? Comments? Online, anybody? Okay, let’s proceed, then. Our next speaker is Robert Kennedy, he’s going to be talking about Natural Gas Infrastructure issues. Robert?

MR. KENNEDY: Thank you, Ruben. My name is Robert Kennedy and I work in the Generated Fuels Unit along with all my colleagues here at the Energy

Commission, and I'll be talking about that final piece to the puzzle, the physical link between supply and demand, the Natural Gas Infrastructure. And I just want to paint what the current picture looks like, and also comment on what the trends are that we see right now.

I just want to cover what I'll be talking about first, I'll start with interstate pipeline status and I'll talk about California, then looking at the national level, and I'll just highlight trends that we see right there, and then I'll move on to liquid natural gas. And for that one, I'll first start on the road market, and then move on to the national level, and then I'll take a look at California with regards to LNG. And then I'll touch upon storage, and for that one, I'll just look at California. And finally, I'll talk about infrastructure disruptions and I'll just highlight one example. I just want to note as far as the San Bruno incident, I won't be talking about that, I'll save that for Katie Elder to talk about in her presentation.

Okay, the first thing I wanted to do is give everyone a primer on what the natural gas infrastructure looks like, what it consists of, and this is a snapshot of the United States and what it all consist of. For example, just that there's 23 international pipeline entry points for the United States, and that's just one way we can receive our natural gas. Another way illustrated by Leon is that we can produce our natural gas from producing wells, and also we can receive natural gas in the form of liquid natural gas at import receiving terminals, shown over here. And from there, it goes through gathering lines and goes through compressor stations which applies pressure to the pipelines, which facilitates the transportation process, and from there it goes to the processing plant where impurities are removed from the natural gas and the natural gas is brought up to pipeline standard for use. And from there, we go to the major long distance transportation pipeline, the intrastate pipelines, and as Paul noted, from there it can go to the power-gen sector, or the industrial sector, and then, when we talk about residential and commercial, at that point, the natural gas is in local distribution lines. And also, the natural gas can also go into storage facilities also, and I'll talk more about that later.

Okay, now I'd like to talk about interstate pipelines, first focusing on California. And first, I have here the six major pipelines, the aggregate capacity bringing pipeline capacity up to the border of California is at 9.3 Bcf per day. And from the border coming into California, to take away capacity aggregate for

California is 8.2 Bcf per day, and I'll touch more upon this point as I move along in my presentation. Since the last IEPR cycle, there were two significant additions and expansions for pipelines that I want to note, the first is the Ruby pipeline scheduled to come online in July 2010, and it is designed to have a capacity of 1.5 Bcf per day, delivering gas from those Rockies out to Malin, a Northern California border. And next, we have Kern River, which had a capacity expansion of 266 million cubic feet per day and that came online in November 2010. Now, I just want to show this on a map so we have a better understanding. This map shows the major interstate pipelines that serve California here, we can see the intrastate pipelines within California, and then we have the intrastate pipelines that I was talking about that brings gas up to the border of California. Here, we have GTN, here is the Kern River that I mentioned earlier, and our Cartography Department was able to trace the path line that the Ruby Pipeline will take when it has finally completed construction. Another note is that, going east from this hub, the Opal Hub right here, we also have the Rockies Express Pipeline that is currently in service. So now, with the Rockies and the additional capacity expansion on the Kern River, and with Ruby scheduled to come online in July, there's a lot more demand – well, pipeline taking gas out of this Hub right here, which has had an effect of driving the prices slightly above, but keep in mind that, as Paul pointed out, when we have pricing differential, that's a signal to build pipelines, so we have oversupply right here, and these pipelines are just responding to that signal in the market. So, it's a slight increase in price, but not much. So, when Ruby pipeline does come online, it will bring gas out to Malin, and even though the price is slightly elevated, they still will be very competitive with the GTN and is expected to back gas out north on the GTN pipeline. Now, as I mentioned before, the takeaway capacity coming into California did not change, but California does have more options now at this border.

And talking about the Kern River, we have additional capacity, the intention of the capacity expansion was to serve the Apex Power Station in Las Vegas, however, the line does continue on to California and that does free up capacity for California. And finally, we have the El Paso System down here, the southern and the northern system, and I'll talk a little more about this later on in the presentation.

Okay, now I'd like to talk about the national level and what we've seen as far as pipeline capacity additions. And right away, you can see that there are significant additions in 2008, keep in mind what the conditions were at that time, shale was really coming on strong, we’re seeing more domestic production in natural gas, we were seeing prices of about $13.00 per MMBtu, so I would say it looked like Christmas time for the Natural Gas industry, that’s why there was a big rush to get all this additional supply in natural gas to market. And as we moved into 2009, you can see there was a big drop-off and, as you all know, that’s when we entered into the recession and trade wasn’t available, a lot of projects got put on hold. But if you look in comparison to years prior to 2008, it is still a significant amount of capacity added.

Then, as we moved into 2010, we saw more capacity added, that’s when the economy was starting to improve slightly, demand recovering, credit more available. The need to get that additional supply of natural gas to market was always there, it never went away. And as we moved into 2011, we see that underscored even more so. EIA have noted that, for 2011, there’s as many as 180 projects planned or already approved to come on line this year, and this is what they’re projecting to see.

Now I want to kind of show what’s going on in the nation, this is the map from a couple of major pipelines I wanted to point out. I mentioned Rockies Express before and this line extends for over 1,600 miles and it interconnects 25 interstate pipelines, connecting a lot of various basins along the way, and so this is the first time that markets out east will have access to Rockies gas. Down here, we have the Texas Independent and Mid-Continent Express Pipelines, and as Leon noted, there is the Barnett shale right here and these were constructed to facilitate bringing gas out east, and there was a lot of local distribution gathering line to get that shale gas to market out in the east. And what Paul noted in his presentation is, like I said, when we have differentials between the ups in the market, that’s a signal to build the pipelines. And in a sense, what this has done by increasing gas competition is kind of smoothed out the differential that we’ve seen, like markets that were previously isolated are now more connected due to the additional pipelines. For example, previously, California had a negative differential, and now we’re seeing it has actually gone positive with respect to the Henry Hub. And this has kind of changed the trend that we were used to seeing in the past there with the big rush to build pipeline infrastructure from north to south and from the gulf, and now we’re seeing flows going from central to east central to west.

Okay, now I’d like to talk a little bit about

Liquid Natural Gas, first talking about world trends and what I have up there is LNG is priced based on fuels in the market it competes with. What I mean by that is, when you talk about the European market and the Asian market, when LNG comes to those markets, it's indexed against the price of crude oil, and as Paul had mentioned, the natural gas oil relationship has kind of fallen apart here in the United States, so when LNG comes to the United States, it's indexed against the price of natural gas, so that's important to keep in mind as we move forward in this presentation. Some of the biggest exporters is Qatar, Indonesia, Malaysia, the biggest importers are Japan, South Korea and Spain. And just a note on Japan, I'm sure we all know about the earthquake and Tsunami that hit Japan, and IEA has noted that it affected 11 nuclear plants, and with the loss of 9.7 gigawatts of capacity, so now they're importing more LNG to make up for that loss. Right now, they're averaging an additional 1.16 TcF per day, and other countries have stepped forward to dedicate additional shipment of natural gas to Japan. And I'll show you what kind of impact that has had on world prices in the next slide.

Well liquefaction capacity now stands at 13.3 TcF per year, and re-gasification capacity is at 30.3 TcF per year, and the U.S. has a re-gasification capacity of 6.3

TcF per year, although a great portion of this is largely under-utilized and I'll show you the reason why in the next slide.

Now we see prices offered for LNG around the world, and as you can see, Japan is offering the most LNG and this has been the case for several years now, now that they've had their nuclear power plants affected, their need for LNG just has been underscored now. They have no domestic supplies of natural gas. So now they've been driving up demand for LNG around the world, and since that's been driving up the price of LNG, and that's affected Europe. Just a couple months ago, we were seeing prices around $7.00, now it's up around $8.43, almost $9.00 to $9.50. But if you look over at the United States, we're still seeing prices around $4.50, $3.89, this price of $7.4, that's a spot market purchase, and as Paul noted, when you get around this portion, it gets really cold, sometimes they buy additional shipment of LNG to supplement their demand. But what this graph illustrates is what impact the shale production has had on the LNG market with regard to the United States, it's kind of shielding it from pricing fluctuation that we've seen around the world. Now, while these prices have steadily risen, I think even now it has gotten around to $11.00, almost $12.00, these prices have remained fairly consistent.

Okay, now I want to talk about the United States, specifically with regards to LNG. And as I noted before, a little is coming to the United States just for the fact that the gap between what is offered for LNG in the United States and other world markets, that gap has been widening and so there's been low imports to the United States, and I'll show this more in the next slide. I just wanted to make a note on the Kenai Export Facility up in Alaska, they recently extended their terminal license, but with the provision that experts must stop when Alaska Rail belt needs gas in it and essentially this is what's going on right now, the pricing dynamics are working such that additional wells have been slowed down, so the gas that they are producing right now, it's going to their local needs up in that area, and none is being exported as LNG. And there's been talk of shale gas allowing U.S. export, and essentially what's happening in the United States due to shale, there's a lot of over-supply, and there's imbalance with regards to demand. And so, a lot of natural gas companies see this as an opportunity to take advantage of supply LNG prices that we're seeing in other world markets.

Back in the spring of 2009, FERC granted Jenn-Air [ph.] [01:36:37], which owns Sabine Pass and Freeport LNG in the Gulf of Mexico, the right to re-export LNG, so these facilities, these are re-gasification import facilities that would receive LNG, hold it for a little while, receive it at a price, and then sell it after the price has risen for a profit. And in the winter of last year, they also put in a request to export to countries covered under the Free Trade Agreement and this agreement was granted, however, these countries include countries like Australia, Peru, Jordan, Canada, countries that are exporting LNG themselves, or are looking to export. If you put in a request to export to non-FDA countries which include, you know, countries in Europe and Asia, the countries that are paying a premium price for LNG at the moment, this decision is still pending. They put in a request to FERC to build a liquefaction export facility and this division is still pending, as well. There is a lot of opinion on both sides of whether the United States should export LNG. People in favor of this idea would say that this would support domestic production, it would provide flexibility to the U.S. market to respond to price signals around the world. Opinion against this idea, people are saying, well, if you export LNG, this is basically another demand point and would drive up pricing in the United States for natural gas, and it would expose us to price fluctuations around the world, which may not be a good thing.

Okay, now I want to show U.S. LNG imports to the United States, and I call this graph the “Tale of Two Cities” because, as you can see, there has been a lot more imports prior to 2008 vs. after, and keep in mind what conditions we had in the United States at this time. As Leon mentioned, we were getting into 2007, domestic production was on the decline, imports for Canada were on the decline, the oil gas relationship was somewhat there, demand was steady, so the United States was willing to pay a premium price for LNG. Keep in mind that we only have import facilities in the Gulf and also on the East Coast, which means we must compete with Europe and the Atlantic Basin for LNG. And so, this was a record year for LNG imports right here. They moved into 2008, that’s when shale really just started to come on here in the United States and we saw a significant drop-off in imports. Keep in mind that natural gas prices was $13.00 for MMBtu, but that didn’t matter because at that time prices offered for LNG in Europe was around $17.00 and, also, in Japan, they were up around $20.00. So that resulted in hardly any LNG coming into the U.S. market. And then, you do see a couple spikes in imports here, and those are the rare occasions where the U.S. price offer fell and tried to rise above that in Europe, and as we get over here, we do see some important, most of this is represented in contracts, the Elba Island and Everett, as right here, bringing in that minimal contract amount, and these are minimal spot market activity right here. And keep in mind, at this point right here, this is where we have the most import capacity that we've ever had for this country, yet we're seeing relatively low levels compared to what we've seen over here.

Okay, now I want to talk about LNG options for California, and as recent as 2007, there were as many as five LNG projects on the table to import LNG for California, and those have since gone away for various reasons, some failed to meet environmental standards, some have noted that, due to the market changing, they withdrew their proposal, and should the market change, they'll come back again. We do have Esperanza, they have proposed a facility in Southern California, however, they haven't submitted an application and they've been in this holding pattern now for a few years now. And we do have some options up in Oregon, Jordan Cove and Oregon LNG – first, let me talk about Port Westward. Again, they haven't submitted an application and they've been in this holding pattern for a long time now. Oregon LNG and Jordan Cove, they've encountered a lot of local and State opposition, and so they have submitted an application, but the process has been very very slow, and, in fact, just recently, Jordan Cove has announced that they now have interests in exporting LNG. And finally, we do have a facility up in Canada, the Kitimat Project, originally it was proposed as a re-gasification import facility, it has since changed plans and been fully approved, and will now be a liquefaction export facility. And we do have Costa Azul on the Baja Peninsula, and we learned from a recent conference call from FERC that they haven't received any shipments of LNG since January, and keep in mind that they have to compete in the Pacific Basin, and so that means you're competing with Korea, Japan, China, and they're offering, you know, almost $10.00 per MMBtu for LNG.

Okay, now I would like to talk about storage in California, and first I'd like to explain what storage is. Storage can occur in three different ways, one is you can store gas in pipeline, which is called line packing, or you can store gas in above ground LNG storage tanks, or, the most common way and what I'll be talking about here, is below ground storage facility. And I have this separated into Northern and Southern California. Working maximum capacity, what that means is, when you have an underground storage facility, you have to have what's called a "cushion gas," which is there to maintain pressure within the facility, and it's always meant to stay there to working gas, that's the gas that can be extracted from the facility. And right now, existing in Northern California, we have 180.6 BcF and that consists of both PG&E and independent storage facilities, and we have a lot of proposals right here that would bring the total up to 215.1 which is about a 19 percent increase in storage capacity for Northern California.

And I just wanted to touch on what storage is used for, also. During times when demand is high, you know, storage is used to supplement that high demand, and during times when there is low demand, the flow in the pipeline is constant, so that's when you see storage build-up. And you know, because of the production from shale, you've seen storage levels both on a national level and on the State level at or above the five-year averages that we've seen for the past five years. In the Southern system, we have Socal Gas at 133.1 BcF and proposed projects would bring that up to about 162.5, which is a 22 percent increase. So, the bottom line is there is a lot of storage available, and because of domestic supply, those levels have been pretty high, and there's more options on the horizon, so we should be able to continue to glean the benefits of storage going forward.

Okay, now finally I'd like to talk about natural gas infrastructure disruption and I'll just be highlighting one example. This happened back February 2nd of this year, and basically what happened in Texas, there was severe cold weather, and this caused pipelines that serve coal power plants to burst and basically took those power plants offline. And the natural gas power plants that were scheduled to help out with this loss in power, they were unable to help, also due to cold weather. Now, what this caused is the electric reliability Council of Texas to implement rolling black-outs, which essentially took – it affected gas processing and gas compressor stations. What this led to was a lessening of pipeline flow along the El Paso Pipeline Southern System, and this led to curtailments of a thousand gas customers in Texas, New Mexico, Arizona, and 88 in San Diego, San Diego Gas & Electric, and this was all going on during a time of high demand. So, San Diego Gas & Electric had to go out to the open market and purchase an additional 1,400 megawatts of electricity to replace the gas-fired generation, and across the region, we saw daily natural gas prices increase to 40 to 75 percent in the Southwest, and this mainly occurred in New Mexico and Texas. In California, the increase in price was there, but it was very slight. So, there's been a lot of discussion as to what happened, there's been hearings, investigation that's been going on, and El Paso has gone on record to say that this was the culmination of a lot of extreme circumstances coming together at one time, talking about cold weather, natural gas shortage, and high gas demand. There has been some questions asked as to, okay, what could have been done to prevent this, some winterization of some of the pipelines, and some of the facilities could have helped. NERC and FERC has launched an investigation in review of this to see what has happened and what can be done. Essentially, they're working together to coordinate a review to look at how natural gas and electrical systems and generation facilities, how they interact, and also how in the future the Electric Reliability Council, what they can do to implement their rolling black-outs so it doesn't affect sensitive areas in the energy industry.

But the bottom line I want to leave with you for this example is that California is at the end of the pipeline for El Paso, right here, and the problem originated in this area, so all along this pipeline, there are other demand points that does take gas off the pipeline and we're the last ones to receive gas. Now, it's a good thing and a bad thing, the bad thing is we're at the end of the pipeline, the good thing is we had more time to respond to what happened, and we have more options available to us from other pipelines, whereas, in New Mexico, in Texas, there's less option, that's where we saw the highest price spikes occur in this area.

So, with that, I'd just like to summarize everything I've been talking about. And the first thing is, there's been significant investments to U.S. natural gas infrastructure and this is in response to the surge in production from shale, that underlying need to get all that growing supply to market that spurred the addition of a lot of local distribution lines, gathering lines, and major backbone lines.

Next is import of LNG to the U.S. has been low, and again, you could trace that to shale affecting that area, so pressing natural gas prices, making it difficult for the United States to compete with other world markets to attract shipment of LNG. And because it's a decline in balance, you have companies now looking at the option to export LNG.

Next is storage is plentiful, and proposed projects will help to dampen natural gas price spikes, and this kind of falls in line with the addition in pipeline infrastructure, addition in storage, there are more options available now, so you see the pricing differentials have smoothed out and because there are more options to store the supply disruption, these price spikes aren’t as severe as we’ve seen in the past.

And finally, recent events have increased awareness of the vulnerability of gas supplies in markets to infrastructure disruption. California produces only about 13-14 percent in-state of natural gas, so that means we import a lot of natural gas from outside of the state, from other neighboring states, and should something happen along that supply chain, that could affect prices and supply to California, and we need to be mindful of that. Okay, with that, I’d be happy to answer any questions or comments you may have.

MR. BRATHWAITE: Not only from neighboring states, Robert, but from neighboring countries like Canada.

MR. KENNEDY: That’s true also. Thank you.

MR. TAVARES: Okay, any questions, telephone, Web? No? Okay, before we proceed to our next speaker, Dr. Ken Medlock, I would like to give you a little preamble about his presentation. As you are aware, some of you are aware, for the last couple of years, the Energy Commission and the staff undertook an effort to actually review our methods and methodologies and the models that we use in order to simulate and forecast natural gas prices and some of the other natural gas parameters. It took a while, but early this year, well, actually last year, the end of last year, the Energy Commission decided actually to keep the same platform that we use in order to build up the model for the natural gas. It is the same platform, but we did not have the model. So, given that effort, what we did, we recommended to the Commissioners and our Management that we would use somebody else's model that was built on the same platform, and so we recommended that we use the Rice University Model. It is a model developed by Dr. Medlock and some of his colleagues at Rice University. So, they developed – or they have a base case that we are going to use for our own design. We also asked Dr. Medlock to make some structural changes to the base case so that it will accommodate our needs, so basically what Dr. Medlock is going to do is he is going to present the reference case and, from there, we're going to build some scenarios and, again, it is a preliminary base case, so we are accepting comments and suggestions.

I think we're going to take about a 10-minute break, and then we'll come back and then we're going to have Dr. Medlock make his presentation. So, let's return about 11:15. Okay, thanks.

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

(Back on the record at 11:24 p.m.)

MR. TAVARES: Welcome back. Let's start all over again here from the beginning. No? Okay. Next in our agenda, we have Dr. Ken Medlock, again, he is going to speak about the Rice Model, all the inputs and assumptions behind the model, and also the modifications that he made to adapt to the Energy Commission's requirements. I want to again emphasize that, from our part, from the Energy Commission's part, it is a preliminary base case, and we are asking you for inputs and suggestions. So, Ken, go ahead.

DR. MEDLOCK: Okay, thank you for having me and sorry I couldn't join you guys, personally, but I guess I'll see you in a couple of weeks, anyway. So hopefully we'll get some good feedback from this. What I'm going to do is sort of move through discussion of the Rice World Gas Trade Model and the reference case results that fall out of that, and show you some of the results that fell out of the modifications for the Western United States that followed from conversations with folks at CEC. So, with that, I'll go ahead and start scrolling.

So, what is the model? Ruben gave you a little background, it's basically constructed in the same software platform that you guys are used to, there's been an asset sale now, so it's no longer Altos, it's now Deloitte Marketpoint, which is a subsidiary of Deloitte, and hopefully that will actually bring some benefits. I just might add, because of the data support they can potentially lend, but they're still getting up to speed, so right now what you're seeing is everything that we've been working on here at Rice, dating back to the end of 2004 is really when we started this exercise, and that's also an important point because no modeling exercise is every just done, we wish it could be that way, we sort of finished the process and now we can move on to the next thing, but the world constantly changes and one of the things you need to be able to do is stay on top of movements in data and a lot of times policy is one of the biggest drivers of movements in data, and to be able to incorporate that into the analysis.

One really important point is the model is non-stochastic, so it's a deterministic sort of equilibrium. So, what does that mean? It basically means that we can't really define probability distributions around any particular outcome, and so that lends itself very favorably, actually, to scenario analysis which Ross will discuss later today. But it allows you to sort of identify some of the more important drivers and the deterministic outcome, and then do some sensitivities on those drivers. One of the ways to think about this is sort of like a tornado diagram, right? You try to pick the ones that are sort of at the top of the tornado, the sensitivity, so the things that have the biggest impacts, and vary those, and then you can actually make assessments about what variation those particular inputs mean for a particular region, or a country, or a state. And, in terms of the State of California, but it allows you to do a lot of very interesting things, sort of construct various counterfactuals, if you will, even. And I think we'll actually do something along those lines, and somebody actually asked the question, you know, what if we didn't have shale? And, in effect, that's kind of one of the counterfactuals you could actually construct.

On the demand side, first I should tell you, the model is actually very detailed and it is a global model, it's not just the United States. That's actually very important because one event in one particular part of the world certainly has ripple effects that extend beyond that sort of immediate region, and in order to understand what those potential impacts might be for regions that aren't directly connected, you really have to model a full set of potential trade opportunities. So, the Rice World Gas Trade Model is a global model. There are over 290 demand regions detailed in the model. Demand is estimated directly to the United States and it is estimated a little bit more indirectly for outside the United States, but quite frankly, that’s because of data availability. We are fortunate enough, we want to do analysis in the United States on the demand side – or supply side, for that matter – to have the Freedom of Information Act, which basically puts a lot of very good data at our fingertips to do analysis with. If you go outside of the United States, that’s not necessarily the case, so you have to do other things. But, for the United States, we divide demand into residential/commercial, power, and industrial sectors, much as I think it was Peter talking earlier – he basically laid it out. There is significant sub-state detail and it varies by region. A lot of it has to do with the nature of the pipeline infrastructure within different parts of the country.

One of the things you want to try to do is capture – and this brings up another point that was raised, it really is – demand is only one part of the puzzle, it’s supply, it’s transportation of infrastructure, it’s all of the above. So, when you think about the location of supplies, or location of pipelines, you really have to site demands correctly as sinks along the system if you want to simulate flows to any degree of accuracy. So, you know, coming up with a way to bring sub-state detail into the model is very important and a lot of that is done based on data from the Economic Census and the location of large known industrial loads in power plants, and for some states, on the industrial side, you can actually use data from, and we actually had a graduate student here last year who just finished up – looked at industrial demand in the State of Texas, but you can use data that is reported at the state level to figure out exactly where that demand is located.

Not every state has 10 regions, Texas is by far the most disaggregated, but it has a lot to do with the fact that it's a large state and it has lots of different regions, both on the consuming and producing side. California is actually broken into four different regions according to actually the CEC specification for the State of California, and that's four different demand regions, that is; although, within individual sectors, there are a couple more, so on the power side, for example, there are a couple more sectors just to capture locations of significant sources of load along the system in the state.

Demand functions are estimated using longitudinal state level data, so what is that? It's also often referred to as "panel data," so it basically means you have a time series within each state for each sector, but you also have, because of the time series within each state, within each sector, cross-sectional variation that can help inform the parameter estimates. And so, what you actually see on this slide are the results of the equations that were estimated for commercial, residential and power generation in the version of the model that I'm actually presenting right now. And we've had some recent discussions around the power generation sector, in particular, that may result in some modifications. This is to try to capture some sensitivities that are deemed important, in particular for the West, so, you know, as has already been said, any feedback is more than welcome so that we can actually make this process better. Oh, by the way, I'll back up again, the drivers there, I think you should recognize a lot of those variables as being ones that Peter pointed out as being important for determination of load in each one of those sectors.

All right, outside the United States, we actually have to utilize a methodology that was developed here at Rice to look at the relationship between energy intensity and the level of economic development, first, so that you get an estimate of what happens in energy intensity across countries through time, so – and it's not – time is not really the important variable, it's really the level of economic development that is the important variable. But, in general, what you see is energy intensity declines, and there are lots of reasons for this, notably improvements in energy efficiency are only part of the story, another major part of the story for declines in energy intensity is structural change in the economy, so moving, for example, from an industrial base that's rooted in heavy industry to one that's more service oriented. So, you actually see a decline in the amount of energy that's needed per dollar of output. That doesn't mean energy use falls, it just means it stops growing as quickly as income.

The next step is to estimate the natural gas share in total energy, and there is an equation there that's basically – it maybe looks a little bit complicated, but it's actually quite simple. It just basically says the natural gas share – it's the double log, and that's actually important because what it does is it creates a variable whose statistical properties are, you know, basically – if I'm looking at the probability – at the density function for this variable, it's basically unbounded above and below with a sort of central mean at whatever the data defines, so it has nice statistical properties with sort of normally distributed kinds of variables. When you estimate this thing, you actually have nice well-behaved function, and basically what happens is you actually see the price elasticity is going to be country specific, so it will depend on if you actually take the derivative of this thing and solve it, the price elasticity depends on the share of natural gas in each country. So, you know, how does that work? Well, if the share is very very high, so if you have a country that's very dependent on natural gas, then they own price elasticity, so how much will gas demand change if the price rises? It's not going to be very much, so the price elasticity is actually going to be fairly low in those countries. What's the reason for that? Well, you can think about this sort of in the abstract, is you've got a country that's heavily invested in gas consuming infrastructure, typically you don't build a lot of redundancy into your capital stock via, you know, energy that's used in the industrial sector and the commercial and household sector, and the power generation sector. If you're heavily invested in gas, that's what you have and that's what you use. Now, some countries see gas shares that are well over 60-70 percent and there you see actually the price elasticity is very very low.

Now, a country that has a very low sort of share of natural gas in total primary energy, you'll actually see a higher price elasticity and that's simply because fungability is more of a luxury in those countries, in particular, not being that dependent on gas means that, you know, if you have really low prices, you'll actually see gas demand begin to creep up and that's largely because the low prices incurred stimulate the investments in the capital infrastructure necessary to facilitate that demand. But, by the same token, if you see a spike in price, that will retreat very quickly.

What does all that mean? Basically, you can see, and this is sort of the generic kind of constructed path, energy intensity generally rises very quickly and then begins to fall and what does that translate into? Well, if you look at energy demand per capita, so you have to multiply the energy intensity by GDP so there is obviously a forecast of GDP involved here, which I will address in just a minute for every country. And then, you can actually see that per capita energy demand continues to rise with per capita income, albeit at a decreasing rate. And then natural gas basically takes a share of that for each country.

Now, how are GDP forecasts done? Basically what we did is we used something called a conditional convergence model, so this is something that's rooted very deeply in development economics literature, but the idea is that countries will, as they develop, converge to a common growth rate. Now, this is not the same as converged to the same level of per capita income because that's actually a notion of unconditional convergence. But for conditional convergence, we say, you know, what do we converge to a common growth rate, well, because as countries sort of hit the frontier, if you will, think about this as a frontier exercise. Basically what that means is that the growth from year to year for those countries, to the leaders, if you will, of the pack will be basically tied to the growth of innovation. So, how rapidly is labor productivity improving, and it's really tied to technological improvements. So, what we did is we actually used to define the referenced growth path, the path of the leader country, if you will, because obviously not every country is at the same level of per capita income. We actually looked at data, historical data for the United States and the UK, you can get this data dating back to the 1800's. And you can see that growth rates against the levels of per capita incomes, this is all in real terms, plotted in the graph there, so those are the blue dots. And you can see there is a lot of scatter, particularly there is a lot of scatter if you're below $5,000 ahead, so there's a lot of volatility in the growth rate at lower levels of per capita income, and that can be tied to a number of different reasons, but what we thought was interesting is, when you moved past sort of that $5,000 range, there seems to be a lot fewer of the blue dots and the blue dots tend to increase in terms of the variance, so you see some growth rates in the U.S., for example, that were in excess of 15 percent a year in that window between roughly $5,000 and $12,000 a head, and then things tend to settle down, which is also very interesting once you sort of pass that kind of plateau, if you will, or that jumping point, into a range that has a lot less variance and, you know, on average is around just over two percent. And this is the per capita growth rate, by the way.

And, you know, what's interesting is the institutional features of economies once they sort of reach a certain level of wealth, all tend to resonate to that point, so there's a lot less variability in the sources of growth, or the sources of volatility in growth, I should say. And you see a lot more diversified economies and things that are more consumer oriented, so on and so forth. So you've got lots of variability. Then, what we do is we put a spline knot to this, and so that's what that red line is that goes through the middle of -- this reddish brown line, I should say – that's actually the best fit and we actually tested various knots in this linear spline regression, and this is the one that actually fits the data the best that you see here, and what that red line represents is the reference path that every country converges to, no matter where they are in the per capita income scale. So, you might ask, well, where does that put China? It would actually put China, because this is all in per capita, I mean, purchasing power parity, dollars, it puts China pretty close to that first vertical dotted line, and so you can see that, if you could bury a sort of Chinese growth rate in there, it's not out of the bounds of what we saw in the U.S. and the UK, it's similar levels of per capita income, so I just point that out to keep it in mind, obviously the countries are different, but it's worth noting because a lot of people always ask, "Well, where would that put China?"

So how do we, then, forecast GDP? Well, we use that conditional convergence model beyond 2015. The first five years of the forecast are rooted on the IMF economic outlook for growth, and we do that because the IMF actually has a pretty sophisticated model of economics and demographics that they use, and we feel like, you know, that's a better sort of source – done by a source of information. So we actually use that and then the conditional convergence model picks up after 2015, and what's kind of interesting, you can actually see that, for the most part, I've plotted the U.S. and China here, but we could do this for every country in the world, it's a nice smooth transition between the two. And what you see there are per capita growth rates plotted against time, so out through 2030.

On the supply side, this should be updated, it's no longer just 135 regions, it's about 145 regions now. Natural gas resources are represented in multiple ways. Leon sort of touched on how you can categorize resource. We obviously use proved reserves, we also have estimates of undiscovered resource, what's technically recoverable, as well as something called growth and known reserves. So what is that? That's growth in existing formation. So, this is not – this is distinct from undiscovered resources in that undiscovered resources are resources defined to be in formations that are known to exist, but have not been developed, or hypothesized to exist, based on the geology and region. Growth in known reserves would be like if you're looking at a reserve accounting sheet at the end of every year, it would be like field extensions and additions. So, this would be the sum of all of those in existing field. Data is actually reported for this particular category by the USGS and that's actually what we use. We use their P-50 estimate there.

North American cost of supply estimates, and cost of supply is kind of a colloquialism, basically what we do is we have finding and development cost curves that are loaded into the model and then, along with the rate of return, any tax payments and so on and so forth, you'll actually get the wellhead price once the model actually iterates and solves, but we actually load in finding and development costs and let the model determine whether or not it's going to economically develop those resources. And for North America, we basically have a really good starting point, it was the National Petroleum Council, a study that was done back in 2003, and we utilized that information to inform the cost of supply estimates for all the plays in North America, except for the shale plays, because the shale plays are obviously new, and something I'll point out in a minute, in that study, the NPC study, we only actually had an estimate of 38 trillion cubic feet of shale in all of North America for that study, so that's just a tickler to put in your brain to let you know how rapidly things have changed and continue to change. But for the shale estimates, we actually have a model that estimates what the F&D cost would be for each of the shales on a dollar per MCF basis, and they're certainly obviously very important factors that you'd feed into that. One of the most important once you get past organic content and, you know, clay vs. quartz, and all that stuff, and natural fracturation, would be the initial production rate of the average well. So, the higher that is, typically the lower the per unit cost because it accelerates your cash flow for every dollar you sink.

But we've developed those costs, I'll show you what those look like in just a minute, there are some short run adjustment costs also built into the model. These actually act to limit the rush to drill phenomenon, so the idea would be, let's say we wanted to model the case of a demand surge, well, one of the things we wouldn't want to have happen is for a massive amount of production to be brought online for a short run demand response, so there are actually short adjustment costs and these represent things like limits on rigs, limits on personnel, things of that nature that really act to drive up costs in the short run above their sort of long-run marginal costs.

We also have technological change, now, the pace of technological change is actually very conservative, it's on the order – it's a little less than one percent a year, that lowers the mining costs. Obviously, when you think about what's happened in the shale play, in particular the innovations surrounding horizontal drilling and hydraulic fracturing, so wealth stimulation, we've seen a much accelerated rate of technological change. So, those are the kinds of things that I think in the scenarios we will potentially address.

So what does all this mean? These are selected regional marginal costs of supply curves, so F&D cost curves, if you will. Along the horizontal access, you can see what the cumulative additions to reserves would be. The vertical access would just be the dollars per MCF that you'd have to sink to get there. The top two are the former Soviet Union countries, so this is a group of countries, it's not just Russia, as well as the Middle East, and here I've just aggregated things up so you can get an idea of the scale of resources available. Then, you can see North America on the bottom left, and Europe on the bottom right. Some of these will be slightly modified, in particular, Europe. Right now, as Leon, I think, mentioned when he was talking, there has been a recent assessment of technically recoverable shale resources released, it was done by ARI for EIA, and they didn't put any cost to that data, but certainly it's the first major assessment that's been done outside of North America since the Rovner Study in 1997 and it's worth looking at that data to see if it can make its way into the study for this particular IEPR now. Whether or not that’s the case, I don’t know. I think it’s one of the things that we’ll have to talk about, but the study was just released about two weeks ago, so if you haven’t seen it, it’s actually a good read.

One other thing that I wanted to mention, I’m not sure if I have a slide in here later that actually highlights this more directly, but the scale of resource, if you look at the former Soviet Union in the Middle East, FSU, you know, that extends all the way out to 3000 TcF, the Middle East extends all the way out to 3500 TcF, the United States, even with all the shale that we’re talking about, is about 1,800, so you’re talking about dramatically different amounts of resource available in all these regions around the world. And that actually comes to bear in a pretty major way when we start talking about LNG export potential from the United States, so we can certainly address that later.

Infrastructure, you know, the required return on investment will vary by region and by type of project. ICRG, the Investment Country Risk Guide, and the World Bank data, we actually creating a mapping using the Gas Investment Risk Index which basically isolates those components from the Investment Country Risk Guide that are specific to natural gas, and created a risk premium that could be applied to a basic risk-free rate of interest for every country around the world. And the those risk premiums actually decline as countries develop, meaning that everything sort of converges to that risk-free rate in the very very long run. So this, for example, in the next 15-20 years, would put investments in Iran or Venezuela, you know, at a higher – the required rate of return would be higher than, say, investments in Australia, or Qatar, or the United States. So there is some distinguishing between regions in that way, even in the reference case.

The Transportation Network is actually very detailed. Capital costs have been estimated looking at previous projects and by hunting for data, quite frankly. All capital investments basically are loud, with the exceptions of some that I will highlight in just a minute. You actually have to in the model construct actually specify those potential capital investments, but once they're specified, you can just turn them on and off. And the reference case typically lets the model decide, so to speak, so what that does is it provides a baseline for scenario analysis, so you can identify specific impacts of very specific types of assumptions that you want to learn.

LNG costs, these are ones that often people want to look at and talk about, so this is a snapshot of what’s in the model right now for liquefaction. Re-gas, it would have been a much longer sort of list, because there’s more variation based on the cost of land across different regions. You can see here that in Australia you have, particularly in the northwest shelf, the environmental issues and the CO_2 handling issues, and so on and so forth, really drive up the cost per MCF. In other places around the world, you don’t have the same sort of level of oversight, if you will. Arctic LNG sources are the most expensive, as you will see, actually, in a few minutes, that really pushes a lot of those potential arctic sources of LNG off into the future. Some of the other major assumptions, first of all, we actually do have contracted flows for LNG modeled into the reference case. This actually has an important effect, in particular, it helps impose the concept of First Mover Advantage, so if you’ve got a contractual relationship to deliver into a region, it can actually, even if it’s sunk cost is higher than the sunk cost of a competing project domestically, because the cost is sunk it can basically win that fight until demand grows into, you know, a position where it can absorb new supplies. But what we do allow ultimately is for contracts to be swapped if they are out of the money, and you actually see this happening in a few interesting regions, which we can sort of discuss later if we need to.

The list here actually highlights some of the major assumptions, internationally, in particular about availability and timing of particular pieces of infrastructure, so you don’t need to read all of these, but you can see here, for example, in the Middle East, Iraqi gas is made available beginning in 2020. There is no Iranian LNG option under after 2030, and there are no Iranian pipelines to Europe and India ever allowed in the reference case. You know, you’re talking about a long time horizon, so varying these is certainly within the realm of feasibility. I’m not sure it’s going to matter for the IEPR study, but it is interesting, nonetheless, in particular for what might happen in Europe and Central Asia.

So, shale in the RWGTM, obviously – and I think this has been highlighted already in the previous presentations, we’ve had a sea change, really, in the way we’ve thought about North American gas markets. Back in the early 2000’s, there were up to 47 different terminals in the permitting phase. I mean, nobody thought all of those would get built, but it was a signal, right? Everybody really thought that North America was going to become a location of premium quality for LNG exports, and so there were a lot of projects that were being developed, you know, to really – with that future in mind. So, when we think about all these terminals that were under certification phase, and then ultimately built because we did add a lot of capacity in North America, these were, for the most part, tied to vertically integrated projects, so there was an upstream pump on it to them, and so what you've actually seen in the past few years are these upstream components coming online, so you know, LNG supplies have been brought to bear, although they're not coming here. So that basically means that what's happened in North America, in particular with shale gas, is it's really created a glut of supply globally. Now, what's happened recently, Japan has helped to soak some of that up in Asia, but what it's also done is really put a lot of pressure on existing – on preexisting pricing paradigms for contract of supplies in both Europe and Asia. Europe is really where you've seen it come to bear the most with a lot of major consumers really demanding at least a portion of their deliveries from countries like Russia and Algeria, to be indexed to local spot market. And that's a pretty dramatic change from what we knew to be the case just 10 years ago, even in Europe.

In Asia, some of the Japanese buyers pre-Fukushima were actually looking to develop a hub and index-type contract – Henry Hub-type contract. Now, I don't think that's really going to get off the ground now because there's a bit of a demand push in Japan now, but nevertheless, it really speaks to an important point. If you increase liquidity, physical liquidity, it really makes it difficult to do things like price discriminate, which at its core is what oil indexation is, and I've got a little slide on that later that I'll talk briefly about.

So, this is a slide, it's kind of a modified version of the McKelvey Diagram, you know, Leon really spoke to this already, but it just highlights what proved reserves are, where they sit in the basket of resources that we try to identify and model, and it also brings up an important point that, you know, it's a misnomer to really focus in on reserves, no matter whether you're talking about crude oil or natural gas, or what commodity, because they really are an accounting definition per reserves. The one that matters is really the technically recoverable resource in the long run because technology allows access to a lot of that stuff that may not be economically viable at the moment. But you know, a little case in point of this is if you look at – I'll use an oil example – oil reserves in the United States, well, right now, I think there's about 12 years of proved reserves left in the United States, but that’s been true since 1945, so it really speaks to the point about the pre-reserve thing and inadequate indicator of supply potential, which is why we focus on the technically recoverable resource base.

Development costs, this is another thing that you have to really be mindful of. There’s a strong relationship between Finding and Development costs and the price of the commodity, so what you see here are Finding and Development costs under two different categories, so the green line is the CLEMS database, that is, Capital, Labor, Energy, Materials and Services, available from the Bureau of Economic Analysis. And the red line is the real cost of developing a well as reported by the EIA, and the blue line is the real price of oil, and this is from 1980 through 2009. I just took a sort of snapshot of recent history here because this data dates back into the ‘60s and the correlations hold up remarkably well. But what you can see is they all move together. So, when you take a stand on what sort of material cost environment you’re going to be in, you’re really setting the bar for where the price of the commodity you’re modeling will in the long run end up.

And so, basically what is in the reference case right now is not a trough, which would be sort of in the late ‘90s, mid to late ‘90s, which quite frankly is where, when the MPC study that I mentioned earlier was doing its work, they modeled everything, which is why you get a very low sort of price environment that came out of that work. But it’s also not at a peak, which would be similar to what we saw back in the early ‘80s, prior to the point that is referenced there, and 2007-2008. So, what you see is something that’s kind of a mid-trend in the trough, and recognizing there could be cyclicality around this, based on the availability of raw materials that are like steel, cement, the availability of skilled labor, you guys probably all heard about the “Great Crew Change,” the idea that the average age in the upstream industry is, I think, roughly 55 years now, so there’s a lot of expertise that is set to retire, and so that could put some strain on labor costs. It’s one of those things that I think industry is really rushing to try to fill that void right now. But it’s important to understand that there is cyclicality in that cost metric.

So what about shale? It’s everywhere, it’s not just in North America. This picture, I have since updated to capture some of the stuff that was done in the ARI-EIA Assessment, but what you can see here are the Continents, this is a composite of satellite photographs on clear nights around the world, you’ve got the

Continents, you’ve got the little white dots, which is where the lights are on, those are our demand syncs globally, you can see the eastern half of the United States, you can see the West Coast, you know, pretty brightly lit, Western Europe, Japan, South Korea, that’s always a fun one to point out because South Korea is not an island, but it looks like one on the map. And then the other thing that you can notice, sort of superimposed on top of all this are blobs of color. Now, these are regions with conventional gas resource. The brighter the color, the more intensely endowed the region is with natural gas and so you notice the Western Siberian basin, you notice the Middle East, you notice North Sea, you notice West Africa, and these are pretty bright regions, and the other thing that you notice is the biggest brightest red spots are nowhere near where the lights are on, and so that means when you model natural gas long-term, you have to be conscious of, you know, how do we connect all those things up?

Where does shale fit in? Well, shale, it just so happens, is really well placed to alter a lot of geopolitical relationships, which Leon touched on very briefly, but also market outcomes. In particular, in Europe, a lot of the shale that is being discussed in France, in Poland, in Hungary, in the UK, in the

Netherlands, and Sweden, it’s all underneath these areas where the lights are on. In the United States, a preponderance of the shale is in the Eastern half of the United States. Again, very well located to meet demand. So, what that means is, if you can develop those resources, you can meet those demands incrementally without increasing imports or even, perhaps, pushing imports back. And so shale has tremendous implications not just now, but longer term.

North America, we know where it is, it’s already been highlighted, so I will skip through this. In the model right now, we actually have about 686 TcF of recoverable resource in North America. The majority of that sits in the United States, about 520 of it, and you can see here where it’s located, so how the model actually has got it allocated, and what the breakeven price is. So, what does that breakeven price mean? it’s not the first well drilled, it is actually the average – it’s the breakeven price for the average well drilled to access up to 60 percent of that resource base. Now, it’s a pretty flat supply curve, so the first well drilled is actually a little bit lower than this, but not much, and so you can see there are some low cost shales if you look in the Haynesville, for example, that Tier One, which is what T-1 would represent, or the Marcellus, that Tier

One, or the Barnett, that Tier One. So, once you start to move through those Tier One resources, you start to get into the more expensive resources and that obviously has implications for costs longer term. Oh, I did put it in here – this was the slide I was referring to a little bit earlier just thinking about LNG exports from North America. When you have to compete for the European market, or for the Pacific market, you’re ultimately going to have to compete with the former Soviet Union and the Middle Eastern sources of supply. On an F&D cost basis, it’s kind of a non-starter, quite frankly. The only way that you could really secure access to those markets is going to be to lock up a certain amount of supply to those markets on an oil index basis. Then, you can actually compete in those markets, but it’s only because a particular consumer is willing to basically pay above marginal costs. And that may be the case, particularly in Asia, I highly doubt it in Europe, which basically means North American liquefaction doesn’t really in my mind have a bright future. As a matter of fact, in the model, it doesn’t go, we’d have to actually force that flow if we wanted to run scenarios around that particular circumstance. But there are ways that we can do that. The bottom line is, on its economic merits, you know, shale is a little bit more expensive than a lot of these low cost conventional resources, particularly when you think about resources that might be sourced from places like Qatar in the Middle East where there’s a lot of – there’s a very high liquids content in the North Field, which basically means you can earn your rate of return, whatever that might be, on the order of 12-15 percent, and sell the gas at next to nothing because the liquids really provide a huge benefit and pay for a lot of capital. So, those sorts of things in sort of an economic reality need to be kept in mind, although we can model those sort of oil index contractual flows, if you will.

The rest of the world, what’s currently in the model, you can see here. The new ARI assessment actually puts this number very much on the low side, so we recognized, quite frankly, this would be low going into it, we just had next to no data to try to develop an F&D curve for a lot of these places because, quite frankly, in most of the places, even in the ARI studies that were analyzed, cores haven’t even been drilled, so there’s not a lot of information about the property of the shale. Where we do have information now through that assessment, we’re going to use that to try to develop F&D curves for these other regions around the world. There is an important point that sort of needs to be brought to bear.

In the United States, we enjoy a very unique market structure – I should say in North America, in general, we enjoy a pretty unique market structure in that the rights to ship gas on pipelines are unbundled from the ownership of the facility, itself. So what that means is that I, or you, or anybody in the room who has got the capital can go out and drill a well and have no risk of accessing a market. So, you'd basically be able to sell the gas.

If I go into most places in Europe, if I go into Asia, that's not the case. In fact, you have large incumbent monopolies that basically own the facility, as well as the right to ship, and so they can block entry. What you have to have is for small production, for production to come on in small amounts and actually access market, you'd actually have to have either a regulatory shift, or an outright mandate, and these things are not easy to do. In the latter case, you're asking government to simulate markets and there's a long history of that not working very well. In the former case, what you're really doing is you're asking Government to institute a change in the form of a regulation. In the United States, this didn't happen overnight, it took a long time. And so it really can cement delays in shale gas production around the world, and I think that's something that has not receive enough attention when people talk about shale potential outside of North America. Quite frankly, and if we didn't have the market structure enjoined in the United States, the Mitchells would not have gone to the Barnett shale and done a lot of the work they did because they would have been, in effect, blocked from marketing that gas and the quantity they ultimately found. We probably wouldn't even be having this conversation about shale if the market structure in the U.S. wasn't what it is.

So, some of the reference case results. European LNG reports definitely grow, you can see here, by country. This is just aggregated by country. It's more specific in terms of facilities into the countries, but you can see here, you know, it's certainly a market of destination for LNG exporters. Asia, though, is the one that really drives the boat, and that has a lot to do with growth in China. You can see Chinese LNG imports really increase dramatically; in fact, it becomes a larger importer than Japan in about the mid 2020's, which is an interesting outcome, to say the least. But it's also important from the standpoint of what if, you know, you can paint different pictures – what if the Chinese decide to actually go after in a major way their own domestic resources, in particular the shale gas that they know exists there, and they could overcome the potential water issues they have? It could really put a dent in this picture and paint a completely different picture for international LNG trade, or what if the Chinese economic engine falters? Obviously, this has tremendous implications for the red bit in this chart, but it also has tremendous implications for a lot of commercial interests that have targeted China as their market of opportunity, and given the fact that there are import outlets on the West Coast, in particular, Baja, you could actually see in those circumstances an increase in imports just south of the border in California.

Where is all the LNG going? This is a global snapshot. Asia is really the LNG story here. The red bit up there at the top is the United States, you can see it’s not very big. Where is all the LNG coming from? Here, you can see the two biggest players, long term, are Australia and Qatar, they account for about 40 percent of global exports by 2040. And through about 2015, 2016, this is all stuff that’s under construction. So, the increases in Australia in the mid-2020’s are largely, you know, due to growth in Queensland outlets as well as growth in the northwest shelf and northern territories, so a couple of locations. And Australia, quite frankly, is very well suited to meet growing Pacific demands in Asia. Qatar with its massive resource base and relatively low demand, you can see growth there, as well.

What does shale do in Europe? Well, most of the opportunity for Russia is to Asia, this also is how it’s another very important point about the growth in Asia, if Chinese growth falters, then this really changes dramatically, as well, but the impact of shale production in Europe basically works to offset declines and actually incrementally increases production as they move past the mid-2020’s. Russian market share actually declines from where it is today in the non-FSU European countries at about 20 percent to just over 10 percent by 2040, so it’s a pretty dramatic change in Russia’s footprint for non-FSU European countries.

Prices, regionally. Henry Hub remains below the rest of the world. The NBP, the European and Asian prices are at a premium to Henry Hub, you know, between $.75 and a dollar, depending on the year, and contracted flows, by the way, would be priced a little bit differently. And I have a note on that, next. In particular, just because you have contracted flows does not mean that a spot market can’t exist, in fact, the picture you see here, you see a portion of consumers, if you walk up the demand curve, that are willing to pay an oil index premium and they do this for security, supply reasons, whatever, there are a lot of arguments that are thrown out there in support of these long term bilateral relationships and, by the way, it's worth noting that the same arguments that have been made in support of that and against liberalization in Europe were very similar, they were very reminiscent of arguments that were made back in the late '70s, early '80s in the United States, and we kind of know how that story turned out.

But spot volumes here represent about 15 percent of total deliveries. There is an important point here and this relates to something that I was mentioning a minute ago. If you can flatten that supply curve, so make it more elastic, it actually becomes increasingly difficult to walk up the demand curve any distance because there are more options to achieve supply at a relatively low price, that's sort of akin to saying an increase in physical liquidity. What that does is it puts pressure on the oil index paradigm and you see an increasing proportion of volumes delivered at spot. And you've actually seen some of this begin to occur in the European market. U.S. LNG imports – you can see here through the 2030's it's pretty meager. There's a bit of surge in the mid-teens, but that is all entirely tied to some liquefaction capacity that's coming on line, it's already under construction and slated to come on line in the next couple of years. And as it comes on line, basically U.S. imports uptick because it’s a market of last resort. But as demands everywhere else in the world continue to grow, you can see U.S. imports continue to decline beyond that point because it’s certainly not the market of first choice.

Now, after the 2030’s, you do start to see an increase in LNG imports. Now, what’s driving this? It’s not shale gas production disappearing, it’s actually declines in conventional basins. And that’s something – that’s part of the point, or part of the story that a lot of people sort of forget when we think about the United States natural gas market. So, shale production, you can see it here, you know, some of the big actors choose the bottom there; near the bottom are the Marcellus and the Haynesville, the Marcellus shale, in particular, I think is one that we’ll do some scenarios around because it is, you know, when you get out to 2040, the largest single producing basin in North America. You see both the Marcellus and the Haynesville, Haynesville actually passed Barnett this year just about a month ago in terms of natural gas production, so production is growing there pretty rapidly, but both Marcellus and Haynesville surpass Barnett by the middle of this decade in the reference case. And then, up there at the top are the Canadian shale, the sort of red and the orange and the dark brown color.

Proposition of production, Leon touched on sort of where things are today, you know, plus 20 percent range, we actually see by 2040, you know, this approaching roughly 55 percent of U.S. gas production. And this really brings up the point I made a minute ago, although it’s a composition graph, you can’t really see it that well. There are pretty significant declines in other places. And that’s largely why LNG is ultimately called upon. U.S. demand, it’s largely a story of power generation, so in the reference case, you can see here power generation demand continues to grow, ultimately at the highest rate of growth through 2040 on an average annual basis relative to the other sectors. I don’t know if you can see the growth rates on an average annual basis in the other sectors, it’s not that – nothing really to write home about, so to speak. Regional pricing, you know, we’ve actually done some work, there’s a study that we’re releasing next – early May that we did for the U.S. Department of Energy, sort of looking at the implications of shale for Geopolitics and one of the more interesting things domestically is, when you do a counterfactual where the state of the world reverts back to what we thought it was going to be in 2000, obviously LNG imports are a lot higher, but you actually see much stronger basis differentials emerging in the mid-Atlantic and Northeast markets than what you see here. And interestingly enough, the moratoria in New York, if you extend that, it really kind of exacerbates the situation, particularly if you expand it to include Pennsylvania. So, it just highlights there is a price for any policy, I suppose.

You can see here the AECO basis, really we could substantially – that has an impact on the basis of PG&E Citygate, why is it weakening? Well, because you've got a lot of shale that's coming on and trying to find a way out. The SoCal border basis is relatively stable through – these are decadal averages through the time period, so we see some strengthening from where it is today, but you know, roughly a dime to $.15. California demand now, real quickly, this is based on reference case inputs from the IEPR study. What we did is we took California Energy Commission's representation of the west, so infrastructure pipelines where demands are located, where supplies are located, and we loaded that into the Rice World Gas Trade Models, so you have the CEC World Gas Trade Model, if you will, and are using that to do this analysis. You can see here based on the demand scenarios that were constructed back then, you know, you've got power generation growing, pretty much everything growing at less than a percentage a year on average, except for the commercial sector, which is right at a percent a year. And I think that, you know, current view of the world, some of this is likely to change in a major way. I think, in particular, in the power generation sector. But these are things that are subject to revision through scenario, obviously. And, again, this particular set of outputs is based on the 2007 IEPR study, just so we could see where it sort of fit into the picture and sort of is a launching point for change.

I think that's my last slide, so if there are any questions, maybe we could hit those. I got through them pretty quick, I was trying to because I know it's lunchtime.

MR. TAVARES: Okay, Ken. Are there any questions, any comments? Okay, can you please get close to the microphone there? We have a question here, or a comment.

DR. MEDLOCK: Sure.

MR. KIRSHNER: Hi, Dan Kirschner with the Northwest Gas Association. Back on slide 33, it shows the composition of production supply, I had -- the same question actually came to my mind when Leon was making his presentation and I wonder how much of this is – and you alluded to this being a kind of a physical play as opposed to an economic play, and I wonder if you took the shale out, so if we were back five years ago and looking at this, would those physical declines be as dramatic? Or are some of those declines being driven by the economics of shale?

DR. MEDLOCK: No, you'd actually see a – there would be a little bit of a reverberation in the picture, if you will, so if you took shale out, LNG certainly goes up to balance the domestic market, demand would be lower because you're in a higher price environment, and the declines would not be as severe because you're in a higher price environment. All right, so that's one of the things shale does is it actually, you know, keeps price from rising as much as it would otherwise. But it also forces because of those lower prices steeper declines than some of these other basins, so it renders them uneconomic at an earlier pace. And by the way, the study – all of that is actually clear in that DOE study I referenced, so that will be available on our website, I think, May 9th is when we'll actually post it, we're presenting it up in Washington May 4th.

MR. TAVARES: Okay, any other questions or comments? Anybody on the phone or on the Web with a question? Okay, Ken, I want to ask you after the luncheon to connect again for a little bit because we're going to be discussing the scenarios and I think we're going to need your assistance. So, with that, I think we're going to break for luncheon, it is already 12:20, so we're coming back in an hour at 1:20, and I expect that to go probably no more than a couple hours after that. So, thank you very much. See you after luncheon.

DR. MEDLOCK: Okay.

(Off the record at 12:21 p.m.)

(Back on the record at 1:26 p.m.)

MR. TAVARES: Okay, let's start again. Okay, welcome back. As you know, we're experimenting here with this technology. The first hour, we're going to be talking about potential scenarios. Just before luncheon, as you know, we had the presentation from Dr. Medlock on the Rice University Reference case and the Commission's, also, reference case, which again is preliminary. Dr. Medlock will not be able to join us, actually, he had some family emergency, but we will discuss proposed scenarios to the reference case, and again, we are accepting any input, any suggestions from you. So, the first person that is going to start this afternoon is going to be Ross Miller, he's going to be talking about potential scenarios, and then Katie is going to be on the side there, too, discussing the scenarios. So, go ahead, Ross.

MR. MILLER: While Ruben is fixing that, I think what we're going to do is I have a fairly short ten-slide presentation called "Proposed Modeling Scenarios." That's just to give a context and broad overview for the more detailed description of the scenarios. I think, after doing that, we should have Katie do her presentation which is on San Bruno and Natural Gas environmental issues because the information in that will actually be useful for us in going through kind of a collective assumption building for the different cases.

We do plan to do a case focusing on the environmental impacts of drilling and development for gas, and another one on potential impacts of San Bruno related pipeline either pressure reductions or scheduled outages and replacements.

After we go through those presentations, then we'll change the focus to the matrix sheets that we prepared to help understand the different proposed scenarios and we've got one large one that tries to get pretty much everything on one page, and you can see the results of trying something like that is pretty hard to read, so we've got an individual page for each of the scenarios. And think of this as more of a framework to wrap our heads around what we're trying to do and what changes we're trying to make and how meaningful we think the results might be from such a sensitivity case. The reason for that is we're fairly limited in the number of cases we can run. After the May 3rd deadline for comments, we pretty much have to have all the work done by the end of May just to get through our internal review process. And I won't bore you with the computer problems we're having, and so we're actually going to make these runs is going to be a challenge. So, we're not able to entertain doing 20 different cases, or 30 different cases, we're zeroing in on possibly eight. We might be able to do a few other simple sensitivities that are important and, after the initial deadlines, we might even be able to do some additional work. So, some of it will be in the air.

If you want to bring up the proposed modeling scenarios presentation, this is almost identical to what I presented at the February 24th Joint Committee Workshop on Economic, Demographic, and Price Input Assumptions for Demand Forecasting; that was an IEPR Electricity and Natural Gas and Transportation Committee Joint Workshop. The slide – there we go, so slide 2 – obviously, we're doing this gas assessment for a purpose, it's broadly stated in the statute that identifies the work for the IEPR, these are some specific uses that the gas assessment might be put to. On slide 3, as the discussion earlier today, I'm sure everyone realizes trying to come up with an accurate estimate of the worldwide economic activity that is the natural gas market is a fairly daunting challenge if you're expected to get it right, meaning accurate, especially the further out in time you go.

So, with the realization of that, and as Ken Medlock, who I think Ruben said can't be here this afternoon, said, you know, the reference case is basically a starting point. The general philosophy that goes into constructing that case is one of, well, let's assume the past, we'll predict the future, so it's a business as usual – or the business of the past is reflective of business of the future. So, we all know that people are talking about making some significant regulatory and other changes or at any point in time a surprise can occur like a major technological innovation that could change the face of the market. Those things are almost impossible to predict with any accuracy, so about the worst thing you can do is do only a reference case and look into no other alternative cases.

On slide 4 is a very simplified description of what the World Gas Trade Model is trying to do and the essential problem is has of all of these interacting in uncertain and independent input variables that are all manipulated by the formulas in the model, and out pops the solution. Ken went over a little bit of the techniques involved, which are general equilibrium models, so when he says it will build out pipelines and other infrastructure, it's doing that economically, so it has perfect foresight, it's looking far ahead and determining whether the economics are right to satisfy the return on investment assumptions that are built into the model, or put into the model.

And so the output is really – it's not intended to be an accurate prediction of what the future market price is going to be, it's basically a price that would have to be sustained for the economic decisions the model made to be feasible. You have to think of it as a conditional estimate, it's the right price for all the input assumptions you assumed, and put into the model. If you have a 100 percent track record of predicting what the actual future state of those input assumptions are, then your model is going to be an accurate prediction of the future, as long as its algorithms are an accurate reflection of all the relationships in the world, and that's also a source of error.

Go to the reference case, slide 5. The assumption building, I'll call it, for the reference case is essentially an econometric approach, although internally here we use the term “small m” modeling and “Large M” Modeling. The large M refers to the World Gas Trade Model, it’s algorithms, and the input you put into the dataset, its operations, and then the results. But in order to get those input assumptions, there’s a lot of what we call “small m” modeling that has to be done. Those are not observations you can just pick up off the ground. There’s data out there, a lot as you saw from Ken’s documentation, a lot of the data comes from energy information, administration, statistics, on which he performs regression analysis, and other data, Census data, economic data, to create the algorithms in the model. But, for example, how much hydroelectricity there was in the past 40 years in the United States and each region is used to make an assumption about how much hydro-generation there will be in the United States in each region for the next 40 years. You can see how with something like that perhaps the past may not be the best predictor of the future, or at least not the only one, even if you posit just the issue of climate change, for example, do we think climate change might affect hydrology so it behaves differently than it has in the past? Then, you’d have to question whether your econometrically-based input assumption based on past hydro is the best predictor of future hydro-conditions.

So, that we would call some sort of potential structural change that we would want to design a scenario to address because we couldn’t really expect the econometric approach to handle a future condition like that, and that’s not to say that we predicted that would be what the future hydrology is, these are essentially a what if approach. We’re looking for whether we have any vulnerabilities or, on the flip side, opportunities in the event a certain future that may be plausible, but you can’t predict it with any certainty, or even any discrete probability of occurring. What you want to find out is what are the consequences; if it’s really really bad, that happens, then you may want to take steps to protect yourself against it, even if you don’t think it’s likely. If you think it’s a really really good outcome, then you may want to take steps to be ready to capitalize on it if it were to occur, even if it doesn’t.

On slide 6, I guess I call it the basic philosophy for constructing these cases. Going into this process, we’re not planning to have – to over-rely on a single point forecast, whether that means the Energy Commission will not adopt a price forecast and, by the way, it hasn’t done that in the past two cycles, so we don’t really expect them to do that this cycle, what we’re really focused on is trying to understand what’s the widest plausible range of prices, flows, demand levels from the model, so we’re basically exploring what possible futures might be out there, given either some contingencies we can’t control, or possibly some policies we’d like to look at the impact of.

Slide 7, 8 and 9 are basically just introducing the cases that we’re proposing to run and for which we need to build the alternative input assumptions to replace the ones that are currently in the reference case. We’re picking cases based on some sort of policy-related question, or issue, and so there I call them “Question Directed Cases.” Case A and B are really just designed to see what happens to us if prices end up being very high or very low, so what are the vulnerabilities on the high side, or opportunities on the low side? So, in order to get the model to come up with a high or low gas price, we’ve got to think of some feasible, plausible input assumptions that might happen, that would all tend to force the outcome in that direction. So we’re doing this to try to assess the consequences, we’re not going to be making a prediction that those future states that drive towards high prices are likely to occur, or one is more likely than another. When we get done, you’ll have 10 cases and it’s human nature for people to think, “Well, which do I think is more likely to occur?” And for us, that's where documentation comes in because, if you have a rationale for constructing the cases, and you can define that well, then that allows the user some hope of assigning a relative likelihood to cases, and even if you can't do that, the cases can still be useful in decision-making, but at that point it's up to the individual risk tolerance of the user. If they just really would not want to suffer the consequences that one case suggests might occur, if this future state happens, you know, China's economy implodes, then they may make a decision assuming that that doesn't happen.

We went into a little bit of the theory of using these alternative cases and decision-making, with the intent of minimizing your regret, at the February 24th workshop, and I think Commissioner Weisenmiller had a document by the National Regulatory Research Institute put into the record, which is I'll recommend that to everyone's attention, you'll find it in the IEPR February 24th workshop record.

Now, Case A and B, in order to get the world gas price to move you have to talk about fairly significant either supply or demand assumptions, so those are going to be focused more on national inputs, changing those. The Case C and E are focused more on the question of what's California's exposure to price, so that's a function of the level of our demand at any given price, in other words, the cost. So, in those cases, we're going to be looking more at what are input drivers that have significant impact on California demand for gas, which of course will in part be demand for electricity, because so much of California electricity is produced by burning gas.

On top of those cases, C and E, those are basically multi-year cases where it will allow the model to build new infrastructure should it find the conditions right to do so. So, consider the result of that as "here's a gas plan." At any given year, you could be subjected to some stresses in terms of temperature, hydroelectric conditions, and maybe even business cycle variations in economic activity, that those plans would have to survive, so the cases D and F would basically just be a stress of the plans that were built in Case C and D, just to see how well or how poorly they performed under colder winter, hotter summer, low hydro, and maybe a little higher economic activity. So, even though we would have constructed a case for low -- generally low gas demand, we're still going to stress that with, you know, temporary high gas demand stress conditions.

The last two cases are focused on, I would say, current events, so we have one that, because of the incident with the San Bruno Pipeline, there is going to be some reaction to that in the industry and regulation, and what we’re proposing to do is to look at basically what are the impacts of that reaction. So, if there is pressure reductions ordered, or stretches of pipeline are taken out of service and have to be replaced over some schedule, then we would look at – we would change the input assumptions to look at the impact on demand and flows and the equilibrium price.

Now, this is maybe the most provisional of our cases because, in general, we don’t want to be running a case that we don’t really think will be that useful. We’re running, I think I mentioned earlier in the last workshop, that we’re running this model in the annual mode. So, obviously the phenomenon of pipeline pressure is not even recognizable to this model when you run it in this mode, it’s basically a proxy through the pipeline capacity and, at that point, it’s the annual capacity for that pipeline. So, this is fairly limited in scope. We would consider the results to be pretty much back of the envelope, and we certainly wouldn’t be interpreting the results to really have significance about – questions about operations or actual real pressure-related phenomenon. That’s the purview of completely different types of modeling analytic techniques. And I don’t even know if we – internally, the Commission is looking at some opportunity to do that, it would be some contract work, but if that goes ahead, it won't be a part of this effort for the IEPR.

That turned out to be Case H that I was talking about. Case G is – half of what you've heard this morning is how abundant and cheap shale gas is going to be in the lower 48 and maybe across the world, so this case here is to specifically guard against a one-sided bias in our analysis because there are voices and information out there that are admonishing us to be concerned about environmental impacts and other areas just following victim to two rows, the assumptions. So, this case is specifically designed to substitute whatever the assumptions are in the reference case with alternate assumptions that are a little more pessimistic about, say, the cost of finding and developing shale gas, in particular, and one way that -- we'll talk about the details there, but that's the overall intent, it's not focused just on shale gas, it's anywhere there might – in Ken's presentation on the reference case, there is a list of environmental constraints that are already placed in there, these would be in addition to all those, this would not be replacing the reference case constraints with new ones, they would be adding them.

The last slide, 10, basically is the decision-making context for this work. I'm not going to elaborate much more on it, I talked about it a little earlier, but if we do complete these cases, we'll have nine cases, they'll each have resulting flows, resulting demands, resulting prices, equilibrium prices. So, the question for stakeholders and decision-makers out there is, well, what is there to do with all this information? And at this point, it's a little early to say specifically other than, "There it is, take it," as Mulholland said when he delivered water to L.A.

So I think we'll move into Katie's presentation because I think that will lay a –

MR. TAVARES: Do you want to take any questions before we move? Does anybody have any questions? No, okay, let me move on to Katie's presentation, it's complementing also the same topic that Ross already presented. And also, I don't know whether you're going to transfer to the next topic, the issue of San Bruno reliability implications and also address some of the environmental concerns a little bit more that we have in regards to natural gas developments. So, let me get that presentation.

MS. ELDER: For those of you who don't know me, that's a little bit too booming for me. I'm Katie Elder with Aspen Environmental Group. I work with staff – some would say torture the staff – Leon was supposed to snicker when I said that because I'm always elbowing Leon and giving him a hard time, and he knows it's all in good fun. But we're trying to do a couple of things with – yeah, Herb is asking him, "Is it really good fun?" But we're trying to change our mindset here about how we do the forecast in a sense, that we're not trying to forecast, if you will, natural gas prices; instead, what we're trying to do is lay out a reference case for comparison purposes, and then we set up these alternative scenarios where we try to use those to capture the plausible range of uncertainty around the key drivers in the reference case.

So, when we give you that reference case and we talk about that reference case, we are emphatically not trying to say that this is where we think prices will go. Rather, what we're trying to say is that, if you assume these things, the model says prices will go there, and if we change what we assume about those things, then the model will tell us prices would probably go someplace else. And it's those things that we change that we're trying to use to inform our judgment and our intuition, and the insights that we can deliver to policymakers, so that's essentially what we're trying to do here.

Now, let me talk to you just really quickly about two details that we're trying to capture in couple of the sensitivity scenarios. If we're lucky, at the end of the day, as Ross mentioned, we'll have a reference case and then we'll have about eight scenarios and we're still trying to figure out – this is all sort of for discussion purposes, which is why Ross and I are sitting here at the table, and say, "Come closer, come closer," we've got to roll up our sleeves here and do some more work because what we're trying to figure out is, are we choosing the right alternative cases – first off, do we have the assumptions and the reference case right? Have we selected the best things to put into that? If we have, then are we selected the right alternatives to look at alternative cases, and in those alternative cases, how do we set up those assumptions? What should those assumptions be?

So, I'm going to gaggle or babble at you for a couple more minutes and then we're going to turn to the spreadsheet, and if you don't have this, you're going to want it. So, in the IEPR Scoping Order, some language, the Modified Scoping Order added some language to it about San Bruno, telling staff that we need to help the Commissioners pay attention to that issue. Obviously, the CEC is not the lead agency dealing with that, but

Chair Weisenmiller has been very emphatic, very adamant that staff needs to be available to help the PUC, to help the ISO do whatever possible, necessary, and to be informative. So, we're trying to figure out what the best way is of doing that. And so, that being said, we're sort of following the proceeding, but clearly in the background, in the backdrop of that.

The Electricity Supply and Analysis Division doesn't really focus on, certainly, on safety, it doesn't focus on interconnections to power plants. Matt Layton will hopefully be here later from the Siting Division to tell you how those issues have come up in siting cases, because they are coming up in siting cases. But this division is more looking at modeling and how the electricity system fits together and that sort of issue. So, that being said, what we're trying to figure out is if there is any way that we can use the model and, if so, what is it, to tell us anything useful about the situation that we face with respect to potentially reducing the pressure and the back-run system that reduces effectively the capacity, the amount of gas that we can deliver to consumers.

So we're thinking, and you can see that, as Ross was talking earlier, and you'll see in this page again, and we'll come back to it a little bit more in a few moments, that we're thinking of doing a scenario in which we simply don't change anything else, but we simply reduce the deliverability on the back-bone system. We're not exactly sure by how much the percentage drop should be, maybe it should be 20 percent because that's consistent with the pressure reduction that the PUC has talked about, we don't even know for sure at this point that the PUC is going to order a 20 percent reduction of pressure on the operation of the PG&E back-bone system. But we're thinking that that's a case that we could plausibly do and we could at least look at that case and see if it tells us anything interesting. It may not tell us anything interesting at all. It's probably also the case that we would want to do that in an extreme weather scenario with either a hot day or a cold day, because on an average day, it probably isn't a problem to reduce that deliverability by 20 percent, at least, that's our gut thinking at the moment.

We think that we would only do that on an annual basis, the model has an annual time period that's built into it. We've done some thinking, some button pushing, if you will, about whether or not there's a way to re-configure the model to do anything on a daily basis. Leon thinks not, but we're still sort of playing with that idea.

There's another approach that is getting launched, Ross alluded to it, we don't think it's going to be available in time to be part of staff's assessment in this 2011 IEPR, and that is to do some detailed natural gas flow, transient flow, dynamic flow modeling. That would be in the kind of model that the utilities use to do detailed system planning like a Stoner Associates model, a GasWorks, there may be something that Argon National Laboratory has, that they've had available in the public domain, or potentially through GTI, even, that maybe is a similar kind of modeling that we could take a look at, but right now we're thinking that it's probably a Stoner flow model or a GasWorks kind of thing. What that would do is set staff up to ultimately be in a position to talk in much more detail about how the configuration of the system with pipes of different sizes and pressures actually are configured to serve load, and how constraints in a given location may make a difference, or may not.

Now, the other thing that staff has traditionally included within the range of its assessments, and I'm very glad that Bill Wood is sitting here because he's sort of been the guy who has done this for years and years and years, he's talked about average transportation rates in the model because that's one of the things that we put in is what the ballpark estimate of what the transportation rates on PG&E and SoCal Gas are. And consumers arguably react to that via the demand elasticity function in the model, and so it has a feedback effect on gas demand.

One of the things that we could potentially also do in this scenario, what we call the “San Bruno Scenario,” is that we could put some increased costs into the model to see how consumers react to those, that’s one additional option that we have. We’ve just done some really ballpark rate impacts, supposed you had to go out and spend a billion dollars on pipeline testing and replacement, we made that number up, somebody could give us a better number, but at least preliminarily if you just run that through a standard approach to not cost allocation, but rather cost recovery, the investment analysis, a billion dollars over -- assuming a 10 percent cost of money recovered over 20 years could add something like maybe $.18 per Mcf to the average gas transportation rate, that doesn’t deal with how you allocate that to individual customer classes. And you can see that we just put together a slightly more detailed spreadsheet that shows $.13; of course, that $.13 doesn’t include any depreciation, so that’s probably the difference between the $.13 and the $.18. So, we could make different assumptions about the amortization, we could make some different assumptions about the cost of capital, or the cost of debt, etc. etc., and be in a position to potentially include that in our model runs.

I wanted to say just a little more about environmental issues. Those of us like me who have been in the gas business for a really really long time tend to think of gas as clean, easily accessible, and lots of it. And so one of the things Ross mentioned, we want to question our own assumptions and be just a little bit more careful about that, and so the other scenario, “Single Case Sensitivity” that we’ve talked about running in the model would be something where we have higher environmental costs. And those aren’t necessarily just happening with respect to the issue about groundwater contamination, potential groundwater contamination, associated with hydraulic fracturing, but there’s a whole realm of other issues associated with fracturing, not only the water use, but more truck trips to deliver the water, the chemical, when you over the life of the well, you re-fracture it several times, so every time you re-fracture to re-work the well, you go parade that set of trucks in all over again, creating noise, diesel emissions, dust, etc. So we wanted to make sure that we provided a way to include that in our thinking. EPA has a study underway to look at the so-called “Halliburton exemption" to the Safe Drinking Water Act. EPA is talking about expanding that study potentially to look at the broader range of issues associated with hydraulic fracturing. We just want to make sure that we're very careful in not assuming that all of this gas becomes available when, in fact, there may be some reasons why it wouldn't. Or, at least allow me to rephrase that. We want to look at the case where what we think will have come true doesn't come true.

The other thing that I will mention is that there is some new evidence that there's also some dissolved methane in the flow-back water, so you inject the water to fracture the well open, and some of that water comes back and is retrieved. The dissolved methane in that escapes and, of course, that is 40 times more – what's the right word – "emissive" is not the right word, but you all know what I mean, than the CO_2.

There are also some other things that going on at EPA that we wanted to make sure we took note of, for example, last April, EPA issued an Advance Notice of Proposing Rulemaking on PCBs in natural gas pipelines and there are some other elements besides the natural gas pipelines that were actually included in that ANPR, but the key one I want to focus on is the pipeline use. Back in the late 1970's when the Toxic Control Substances Act was passed, there was an agreement among 13 pipelines in EPA about the level of PCBs that were allowed in gas pipelines. And those 13 pipelines in EPA agreed to a level of 50 ppm. EPA has recently, like within the last couple of years, learned that several pipes never got below 50, in fact, there were some instances reported where there were levels experienced above 50 ppm. So, EPA in its wisdom decided that’s a problem, this is not what we expected the industry to do – move it back? Is that better? Okay, good. I like that better too, thank you. EPA decided to take another look at that and to push people’s buttons about can we get below 50 ppm. And so the ANPR that they issued last April says, “Let’s talk about taking that standard that is 50 ppm and push it to 1 ppm, the target date for implementation of meeting that 1 ppm standard is 2020,” and INGA, the Interstate National Gas Association, has been fairly vociferous in trying to explain that, first off, we don’t think that the 50 needs to be changed on its face; a second thing they’ve said is that, if you want to get below 50, if you really want to get to 1 ppm, the only way to achieve that is by replacing piping compressors. And so, there, you’re talking about several tens of billions of dollars to do that in the 13 pipes that were the subject of the old deal in 1979, and it’s not even clear at this point that we're only talking about those 13 pipelines. One of those 13 pipelines was Transwestern, by the way, and I don't know the list of all the others off the top of my head. So, that's one of the things that we want to pay attention to, and that could be a potential environmental compliance test that we test in the model. If that rule were to be implemented, there would be enormous costs to the industry.

There are some other rules at EPA, like some changes to the New Source Performance Standards, there's the Air Transport Rule, there's the potential for a coal ash rule where coal ash is declared to be hazardous waste, which imposes some additional mitigation when somebody goes in to do work behind a fence on a coal plant and suddenly finds that now, because they've done, they've touched the site inside the fence where the coal ash is present, they must remediate. It also turns out to be the case, and they're talking about a Mercury rule on top of a coal cash rule, there's some new hourly monitoring requirements for an NO_x and So_x, as well, that could also have an impact. So we want to make sure we pay attention to all of those kinds of things that push changes in electricity resource portfolios.

The last thing I want to mention, though, that's going on at EPA are their efforts to change the reporting requirements for greenhouse gas emissions. They imposed a new rule, it seems like they adopted the rule late last fall, the first reports under the new rule are due next March to cover calendar 2011, and for the first time, the upstream parts of the industry, even small sources down to about a 25,000 emission ton level, will be required to report their greenhouse gas emissions. It doubles the number of covered entities that have to report their greenhouse gas emissions. And so we’ll see what impact that has. EPA says that that’s designed to help them figure out what new rules to adopt that would cover some of those smaller entities.

Now, that was kind of conducted in association with their announcing in a technical document – and you had to read fairly far into the technical document to figure out what the real import of this was – but one of the things they found from the entities that were reporting their greenhouse gas emissions on large emission sources was that their assumption about the upstream field and production emissions on greenhouse gas emissions of natural gas were vastly understated. And we have the table here that is actually from – I’m looking for the pointer – but this table actually comes from the EPA document and you can see that they’ve more than doubled the emissions, CO_2 equivalent emissions of natural gas, up at the production end. The other sectors changed a little bit, processing transmissions in source and distribution, but not very much, in fact, distribution not at all. But this big change here that doubles, in essence, the emissions that are coming out of the field at the production level, was a surprise to a lot of people. Now, when Leon talked earlier about, I think, 117 – was it tons of emissions per MMBtu of natural gas, that's on the combustion side, that emission happens when the gas gets burned. So, what I'm talking about here in this table, what EPA is talking about, are the upstream emissions in the field, in the production field. And as I mentioned earlier, some of those emissions may be happening when the gas from the fracturing – not the gas from the fracturing – but the water, the flow-back liquid from the hydraulic fracture comes back to the surface and is retrieved, some of those emissions are happening there, some of those emissions are believed to be in bad O rings, for example, on equipment. So those kinds of things now, because EPA has got this reporting rule in place, are going to be taking a much harder look at. So, that could end up changing our picture of what the real emissions value of natural gas is, the CO_2 emissions value of natural gas is ultimately.

The last thing I wanted to point out to you is that our preliminary reference case here doesn’t make any assumption about greenhouse gas emissions, or carbon emissions, or a cap and trade program either in California or U.S. wide. It turns out to be the case, though, that if you start looking at the electric generation gas burn, gas demand that we have coming out of this preliminary reference case, that it is almost as high by 2030 and certainly by 2035, as if you replace most of the coal in the U.S. with natural gas. And so, while we weren’t explicitly assuming that we got that kind of case, it looks like effectively what we got. And so, when we started to create a higher gas price scenario that presumably could have – you would think that one way of doing that would be to increase the gas burn, in other words, assume that natural gas pushes coal out of the electric resource portfolio U.S.-wide, that tool may not actually be available to us because it’s effectively already been done, so that’s one of the little things we have to pay attention to. We have also not in the case made any assumption about the AB 32 implementation, cap-and-trade in California, or how that would work, and we’re really not exactly sure how we would reflect that in the model, would it be added to the gas transportation rate, the gas cost, how exactly would that work?

The last point I wanted to make was that there is also a sense that, by 2050, if you have an electric resource portfolio where you have pushed coal out and replaced it with gas, and even some combination of gas energy efficiency, renewables, etc., that by 2050 the emissions associated with that would be high enough, again, that you'd have to push gas out of the portfolio. So, to the extent that we think that folks across the country would be implementing more gas in the portfolio, certainly probably not here in California, but in the rest of the country, it turns out to be the case that, by 2050, you're right back in the same soup that you can't meet the emissions targets.

So now what I want to do is turn to this really complicated small print spreadsheet, and hopefully this is where we're going to pull this altogether for you. And I have to even put on my glasses to read it. Over on the right-hand side, we listed the key assumptions in the reference case, and so that's our sort of shorthand characterization on all the important assumptions that we think are embodied in the reference case. Now that I've pointed you to the far right, let me direct you back to the really far left because, in the left-hand side, that far left, you'll see the categories of assumptions. So, one category is Economic and Demographic Assumptions, some Weather Assumptions, some assumptions about Other

Elements of the Electricity Resource Portfolio, What’s Electricity Demand? What do the Prices for Electricity, Natural Gas, and Fuel Oil potentially do? Precipitation. We have some policy drivers that have to do with greenhouse gas emission under efficiency, how many renewables are in the electric resource portfolio, what’s the combined heat and power assumed in the electricity resource portfolio, how much distributed generation is in the portfolio, how much use of natural gas and electricity is there for transportation. We have an “Other” category. And then the last two, bottom of your left-hand, those two categories are environmental protection, public safety kinds of variables, and then supply. And we know from listening to Leon earlier that the supply is absolutely really critical. So, now, knowing what is on the range of assumptions, the types of assumptions that are specified on the left side, and knowing, if you’ve actually read it -- I’m not going to walk you through it, but I’m not sure I need to -- what kinds of assumptions are embodied in the reference case, now what we try to do is figure out for our potential alternate cases A through H, what are the variables that we want to change from the reference case values. So that’s the way to think about this chart.

Now, for each one of those cases, A through H, the variables that we're going to leave the same as what's in the reference case are indicated by, first off, it's shaded in light gray, as opposed to the white, and secondly, it says "Reference Case Values." So, anyplace where you see that it says "Reference Case Values" and it's shaded in gray, it means that we're going to leave the assumption on that particular issue the same as we have it in the reference case. And so now you begin to see sort of the things that we're thinking about changing to create the ultimate cases. If you go with me to the column that's labeled "H" which is our single variable sensitivity to deal with the reduced pipeline pressure case, virtually the only thing that we would change in that case would be the deliverability of the backbone system in Northern California and potentially weather, high or low, cold winter, hot summer day. And we might look at whether or not we should add something to the transportation rate.

So those are the three tweaks that we're thinking about doing to create that case. Walk back with me to Column G, go one to the left, so in the case where we were at increased environmental mitigation cost, or maybe that there's just not as much shale that gets produced, shale gas supply that gets produced as we think in the reference case, how could we reflect – build – that case?

Well, there’ a couple of different ways that we might build that case, one is that we could, as noted at the very very bottom of your page, we could just take the supply curves that Leon showed you earlier, and we could move them to the left, that would be one way of doing that. Think back to the graph that Leon showed you that had a red supply curve and a blue supply curve, where the red was from the ’07 case and the blue one, I think, is the 2011 assumption, we could move it to anywhere in between those two. So that’s the kind of input that we’re looking for is, where should we move that to? Is that the button that we should push? Or the level that we should pull to build this case? Or, the other way that we could do it is we could add some environmental compliance costs into the O&M charge that is an adder onto the supply curve, an adder onto the marginal production cost. And we’ve done some preliminary work, in fact, Leon has done some fabulous preliminary work, where he begins to look at what that compliance cost might look like. So, if we believe that gas producers were all going to implement environmental best practices, how much would that actually cost them in addition to the current costs of gas, to implement those practices?

So we could add that into the O&M phase. And to the extent that folks have other ideas about how we could accomplish that case, how we could build that case, we're interested in hearing those. Yeah, jump in. This is meant to be more interactive.

MR. MILLER: Just to, I guess, observe some general principles that have been illustrated by what Katie said, is our Commissioners don't want us to come up with a range that is so broad of results, that is so broad they don't find it useful, which we interpret to mean we need to be looking at alternative states of these future drivers, but the values we assume for them need to be plausible. That doesn't mean likely, that just means plausible, and that goes back to if it's – we think it's low probability, but it's a significant impact, and it's a consequence, we probably ought to be at least aware of possibly happening, even if we decide later not to protect against that, at this information gathering stage we wouldn't want to exclude that. So, for the example of – Leon is gone now -- but the 40-80 cents per MBtu, that's based on a review of what it's costing in the field to do some of the additional environmental mitigation or protection measures, so there's a basis for those numbers, it's tied to something that you can say, "Well, this reflects these people taking that action." The other dimension of executing that case in that way is, "Well, over what geographic range do you assume those protections would be required?" Or, "Do you want to just assume it's adopted as best practices everywhere?" Part of this is it is very, in some ways, subjective, but it's important to understand how we construct the cases because what conclusions you can make about the results are going to be dependent on that. I mean, we may want to say – we may want to construct a case like that saying, even the people living there and the national and local chapters of the Sierra Club, NRDC, will be completely content that this is a price you can get shale as at, safely. Then, that could be an approach. And so, obviously, we want to ask those people most affected by what their opinion is of how safe does it have to be, put it in the model, and it will ripple through and say, "Okay, well, we can get shale gas at that price." But that is an approach to constructing the case and, if you understand it's that way, then you understand how to – what conclusions you can make and what conclusions you can't make from the results. So, there will be a lot of play like that in constructing these cases.

Another thing I wanted to say is just about time management. So, Matt Layton has the final presentation. We can talk about this for quite a while, I don't expect us to have reached agreement on actual numbers to modify the reference case input, or even maybe the mechanics of how to do it. You have until May 3rd to give us more suggestions, but I would encourage people after you've thought about it more, I realize we haven't given you a whole lot of time to think about this incredible variety of detail. The sooner you either contact us informally with your thoughts, or provide your written comments, the better. That gives us more time to implement it. And that's not to say that if you want until May 3rd, you haven't got a chance of affecting our decision, that's not the case, we may be internally deliberating ourselves for that long. But if you feel you have a good handle on some of these key drivers, if you're sitting on information that might not be available to everyone, and you see it would be useful, sharing that in some form would be greatly appreciated, and the sooner the better.

The other thing I'd say is, for example, we're in the high gas price case, Case A, we could probably think of a thousand different alternate assumptions in the reference case that would all lead to higher gas prices. If we put them all in, I'm not sure what value that case would have, other than, well, gee, it's probably the worst possible case and the price only went up to $12.00, so, I mean, you do get something out of that. But, so, part of what we have to balance here is plausible combinations of plausible changes to key drivers. So, one thing that you say many many internal electric system and gas system reports on is one of the key drivers Katie mentioned, is national either EPA or climate change directed constraints on coal generation, or imposition of incentives or mandates for shutdown, or just the sheer economics of having cap-and-trade. There have been a lot of studies that, unfortunately, all 20 studies don't come up with the same number, which we can just plug into our study to come up with the range of, you know, between two gigawatts and 80 gigawatts of coal shutdown by 2015, so that's a pretty large range. We can split the difference and say, "Well, how about 35?" And we could put that in. And, say we do that for Case A, well, the next question is, "Well, are there any other changes we'd also want to make that would lead to high gas prices?" And I think logically the way you'd look at is it is, "Well, what were the conditions of the future that we assumed that led to our assumption that coal plants would shut down? Are there any other key drivers that, given those conditions, those should probably also change?" And some of those changes might be countervailing, I mean, if you have -- if you're assuming coal plants shut down because of air quality or climate changes, then you might also assume there is more incentives for energy efficiency, more incentives, if not mandates, for renewables, and those are going to go into the opposite direction, those are going to decrease the gas-fired generation. So, this is a blend – Ken used the term “tornado diagram,” if we were just going to do 50 different single variable sensitivities, we could construct a tornado diagram and see which of the 10 are the biggest drivers. What you’d have if you did that was some good information about individual sensitivities, you’d still have to be wrestling with this problem of, well, are all those things going to happen at once? Or in about combination might they happen? So, in one sense this problem is kind if irreducible, you’re either forced to imagine a thematic scenario of the future where you can predict the correct direction of 20 different interacting things, or you do single variable sensitivities where you don’t even attempt to do that.

MS. ELDER: Let me just walk through C, D, E and F really quick so we can put that in the mix, and then I’ll come back and give you one more example, and then maybe we can go ahead and go to Matt if that makes sense. Don’t rush on your account? You’d be happy if we used all the time. Okay. All right.

So we’ve talked about G and H, single variable sensitivities, we’ve talked a little bit about A and B, the high and the low case, where we’re trying to come up with a range of things that would give us higher natural gas price, B is a range of plausible things that could happen that would give us lower natural gas prices relative to the reference case. C, D, E, and F are all California specific cases where C and E are high demand case and a low demand case, respectively, and then what D does to that high demand case is add weather sensitivity to it. What F does to the low demand case is add weather sensitivity to it. And so we can see in C a high demand California case and, then, in D, we further stress that with some bad weather, if you will, and we do the same thing on the bottom end with E and F where we create a low demand case, and then we stress that with even lower demand. So, that's what those are about.

Now, let me give you the one example that I promise I think will really help this all coalesce in your brains. If you will look down the page with me to Energy Efficiency on that left-hand side, and then glance all the way across the right to the reference case column, so we know that in the reference case, we've got electricity demand across the U.S. growing at 1.12 percent, that's what the model assumed. The small "m" model, thank you, Leon. So, we know that, in the little model, in the demand model, which is our little "m" we talked about earlier, we've got U.S. load growing at about 1.12 percent, we feed that into the big “M” model, the World Gas Trade Model, that was the distinction between little “m” and big “M.” Now, we could, in a low gas price case, one of the ways that we could construct a low gas price case, is to assume that energy efficiency reduces that load growth, so that load growth would be the less than 1.2 percent – don’t know if the thing that we should assume is to cut it in half, that would be something like .6 percent load growth, or .55 percent load growth across the country, pretty dang low, but that would induce much lower natural gas prices. So, that gives you a sense of the kinds of things that we’re thinking about tweaking, or playing with, that we’re interested in input on, what would be a reasonable thing to assume if we want to use energy efficiency to help create a low gas price scenario? What should we change that energy efficiency assumption to?

Let me choose another one. Renewables. Just one more down on the page. We know that, in the EIA Annual Energy Outlook, which is what Dr. Medlock used to construct some of the input assumptions in the little “m” that got fed into the big “M”, we know that, in that case, EIA assumed that renewables – and they include convention hydro in their renewables number – they have renewables growing to be, I think, 17 percent of the

U.S.-wide resource portfolio by 2030. When you strip out the conventional hydro, they were letting those renewables grow to become 12.5 percent of the U.S.-wide electricity portfolio. Maybe we'll want to assume that U.S.-wide will get to 20 percent, that would be another thing that we could throw into the model. Les is shaking his head at me, okay, don't do that. But I choose that just to give you a sense of the kinds of things that we could play with and what directions we would want to play with them, and that's a key thing that we're asking for input on – by May 3rd, if not sooner. Are there any questions as you look at this page and you see all this fine print on this page? Is there anything that jumps out at you immediately? Yeah. You want a mic so that people who are listening can hear you.

MR. BAMBURG: Les Bamburg, Sempra LNG. One thing it seems like would be better to understand is, when you said on account of the base scenario that natural gas demands growing the same as if you assessed a giant carbon tax, it would be good to understand is there still coal consumption there, is that just gas demand? Or is that essentially displacing all of the coal-fired power generation? And why is that occurring.

MS. ELDER: It turns out to be the case – I can add a bit of detail to that – it turns out to be the case that the 25-year demand period that creates the dataset on which the demand equations economic regression is run is 1986 to 2008 or 2010 – it’s basically a 25-year period beginning in 1986. It turns out that, in that 25-year period, there was a huge shift of natural gas in the electricity resource portfolio across the country. So, when you use that equation to project demand going forward, you’re essentially projecting that same trend forward. And you don’t have to, in the little “m” there isn’t an explicit resource portfolio breakdown, you have to infer it from the gas burn and the growth rate in the electricity demand. And if you spend any amount of time doing that math, what you’ll see very quickly is that basically, by definition, most of the coal had to get pushed out because, otherwise, that cash burn can’t be that high, or else you’d have to have a really high growth rate, or you’d have to have virtually no renewables, so with the renewable growth rate, the load growth rate, and the gas burn, those three things lead to the conclusion that you effectively have a resource portfolio that pushes most of the coal out.

MR. MILLER: In Ken’s presentation, he had, I think, the third slide may have been demand equation. If you looked at the electric generation, you can see that an explicit factor in that equation is what is the total electric generation, and then how much of that is renewable? So, there's no assumption directly made in that econometric equation of what the coal generation was. The coal price is in there because some of the areas are going to switch between coal and gas. And then those are derived in part from his inspection of the different EIA or other sources. Now, we can make available all of the input, the small "m" input modeling spreadsheets, I believe, we can post those. So, those are the inputs to the World Gas Trade model, which that, unless you have it, I mean, we would offer that in the way of documenting our input assumptions, how we generated the independent input variables for the model. But there's license restrictions on – well, if you have the license, we can give you the whole thing.

MR. BRATHWAITE: The only thing that comes from the small "m" model that goes into the big "M" model is the referenced prices and qualities, so I just want to be clear. I mean, all the other stuff are just inputs to the small "m" or which generate your reference price or reference qualities, which then is put into the big "M" model. I just want to make that distinction, okay?

MR. MILLER: But you're using the word "reference" in a different sense than reference case, correct?

MR. BRATHWAITE: Yes, yes, well, let’s say – yes, it gets so confusing with the terms around there. Okay, so when I say “reference” prices and quantities, I mean starting prices and quantities to run the big “M” model, okay?

MR. MILLER: Because it’s a general equilibrium model, it’s a start and then it iterates to a completion.

MR. BRATHWAITE: Exactly, yes.

MR. MILLER: So that’s why in some of these cases and, Herb, you were asking about price elasticity, we put in an assumption about what electric generation demand is going to be, but that’s also an output of the model. If there are price elasticity demand assumptions for all the fuel uses, that’s how it can switch between coal and electricity, and that’s how it can decide just to use less if the prices get too high. Now, they may be very inelastic, the elasticity’s, and we also have the ability to turn them off completely for doing more deterministic runs, but that is a feature of the model. And that’s why Leon was using the term “reference” quantities because you have to start this model with some assumption and it will iterate to, but perhaps different final value.

MS. ELDER: Any other questions, comments, notes? Tim has got one for us.

MR. TUTT: H, Tim Tutt from SMUD. I may have missed it this morning in Paul’s presentation, but California, at least, has adopted a cap-and-trade program and there’s a floor price for carbon, and I did not see that included in any of the price estimates for natural gas. I’m wondering if that’s part of the picture or not.

MS. ELDER: Well, that’s one of the questions we’re raising, is that, first off, it’s not explicitly included in the model; if we wanted to include it somehow in the model, we’re not exactly sure how that should be done. Potentially, it could be done as an adder to the transportation rate that all gas customers face, that would be one way of doing it, so we’d be interested in more input on that.

MR. MILLER: And if we put that in the World Gas Trade Model, then there would be some opportunity for demand to be reduced because of the additional cost.

MR. TUTT: Correct, and so – and understanding that this is a California policy, not a world policy at this point, I understand the dilemma there. Katie, you showed some slides showing that the DOE or EPA had estimated a significant increase in the GHG signature from production of natural gas. I guess the question I had there was, is that because of Fracing? Or is it just an understanding of the basic structure? Because there’s certainly different GHG signatures if you take – go into methodologies like fracing or even LNG, and I'm wondering if that differential GHG signature is at all being considered.

MS. ELDER: I don't think that there's a way – Leon will correct me if I'm wrong – I don't think there's a way to explicitly include that in the model. I mean, I could imagine you're thinking about a different cost adder for different GHG signatures for different gas sources, but –

MR. BRATHWAITE: Can I ask exactly what are we talking about? What is he –

MR. MILLER: If you were to assume a carbon cost and apply that to gas production, and knowing that all the different types of gas production like OCS vs. Marcellus shale might have a different carbon emission factor, can you get the economics of that included in the big "M" model?

MR. BRATHWAITE: Well, natural gas is natural gas, CH4 is CH4, that to me doesn't make a difference; however, if in our limited judgment we decided that there could be differentials between the carbon footprint between, say, shale and conventional gas, or clean shale and OCS or something like that, yeah, we could put in differential at a cost adder if we so choose, that's a relatively simple process. I mean, developing the numbers might be quite complicated, but the process of doing it is relatively simply.

MS. ELDER: In other words, once you had a number, once you developed a number, you could put that into the model as a cost adder.

MR. BRATHWAITE: Yes.

MR. TUTT: But there are no plans to do that during this round that you guys know?

MR. BRATHWAITE: Well, there is one of the scenarios where we will do an added environmental cost, the extent to which we will apply that, we are not certain as of yet, but there is certainly one scenario on the table for doing that, yes.

MS. ELDER: To answer the other part of your question, which is why the EPA number for the field and production emissions has gone up so much, I don't think that that's related to the signature issue, I think that's basically EPA saying, "In 1996 when we first estimated these, we did it on the back of an envelope with a bunch of assumptions, and we've just learned that those assumptions were faulty."

MR. TUTT: Okay, and my last question, I think, is relatively minor and maybe it makes no difference whatsoever, actually, but there's an increasing use of biomethane injected into pipelines, does that at all affect the distribution rate or is that factored into the model at all?

MS. ELDER: It's not. And I have an idea, Tim, Leon will correct me if I'm wrong, though, but I have an idea that the percentage is so small that it wouldn't make any difference at the margin, it's just not going to change anything. Oh, my gosh, Leon says I'm right. I'm just messing with you, Leon.

MR. TAVARES: And we can also have an opinion from Herb. Oh, he's talking to Leon there.

MR. MILLER: I guess at this point, if there's anyone else who has some specific suggestions or comments about any of the scenarios, this would be a good time to come up and tell us, or ask us.

MR. TAVARES: And, again, keep in mind that we still have until May 3rd to submit the comments and suggestions, but in the mean time, between now and then, I mean, we are open to any suggestions after you study those cases a little bit more carefully.

MR. MILLER: I would –- I think we talked about this -- Column D and F, as I mentioned, were to stress the high and low gas demand case and the column that talks about – or the row that talks about amount of hydro-electric generation, in Column F, I think that's not what we intended. It should be low hydro in both cases, so we're talking those cases that were developed under the assumptions in Column C and E, and subjecting them to the same stress conditions, which would be cold winter, hot summer, low hydro, which means more generation gas demand, and then possibly a little extra economic activity leading to higher demand. And so, those sensitivities, those you would think would be the easier ones to decide on, for example, if they're just using 20-year average for heating degree days, then you say, "Well, let's just pick a number that's not average," so the question there is, "Well, how severe do you want to get?" And we can say – and, in fact, those are some of the very few variables that we actually have a probability distribution for, so we can even do it in standard deviations. What we then run into is the – you can call it co-variants. If you looked at – you can find a year that looks, "Oh, gee, we're lucky, we got a hot summer and a cold winter, so let's use that year," well, you find out that those are always the high hydro years, which is the opposite direction we wanted to go. So, when we combine these different individual assumptions, as I said before, we're trying to look for plausible combinations, as well as plausible individual changes, so if you think of the idea of an ever observed condition, we don't want to assume heating degree days and cooling degree days and at the same time we're assuming hydro levels, that those three have never ever occurred before, they've never been observed to have occurred. And that's because they're not completely independent variables. So, there will be some judgment there, so what you'll end up with is those cases will not be the worst possible state for each of those, say, four variables, collectively, so it won't be the worst heating degree day/year, the worst cooling degree day/year, the worst hydro year, and the worst economic conditions, it's going to be something less than that, but it would still be stressed. And you could use the same conditions to stress the reduced pressure case, unless, if you know, we have temperature-related safety standards that have their own assumptions about these things, there's no reason we can't use those in that case, or the others.

MS. ELDER: Peter also pulled out the extremes on the cooling degree days and the heating degree days, and the question that popped into my mind was how did those in that 20-year period that we've got the data for, in the little "m", how did that compare to the PG&E or the SoCal Gas system design day conditions of the cold winter day, or whatnot? Should we be using those instead? So, another idea of input.

MR. MILLER: So, in addition – oh –

MR. PATRY: Hi there, Dan Patry with PG&E. Just a quick question on the Reduced Pressure case, and I'm try to understand the time horizon that staff is considering for that pipeline case, is it five years, 10 years? Just because my sense is I can't imagine we would expect the reduced pressure scenario to occur in perpetuity.

MS. ELDER: Exactly, exactly. We're thinking one to three, tell us if it should be five, but that's our gut feel at the moment.

MR. PATRY: Okay.

MS. ELDER: Because you're right, you wouldn't do it in perpetuity.

MR. MILLER: Right. It's determined by whatever estimate we get of the regulatory effect. I mean, this is an estimate on the gas market of the mitigation for that problem.

MR. PATRY: Right, and in the long term sense, I would imagine that any of those, you know, the costs or the kind of scheduled outages associated with any backbone or things like that would occur during low demand times, such that the impact would be mitigated a little bit. But –

MR. MILLER: And if they schedule it that way, I mean, that's part of the information we need to make a judgment of how valuable doing this might be.

MR. PATRY: Okay, thanks.

MR. TAVARES: Can you please –

MR. MILLER: He’s going to say that this is at best going to be a back of the envelope approach.

MS. ELDER: A back of the envelope case.

MR. BRATHWAITE: Yes, I want to say that because this is very important, okay? So, even though it has been said, I’m going to say it again, this case, this reduced pressure case, at best, is a quick dirty back of the envelope case, and as Ross has said many times, I don’t know what insights we’ll get from it, but we’ll try to see if we can extract some useful information from the case, so please, I know we’re in a public forum, don’t walk away from here thinking that the CEC is going to do this great wonderful case about this reduced pressure, we are not. Okay? Thank you.

MR. MILLER: And we’re just the staff.

MS. ELDER: It’s not going to provide the answer to everything, that is for sure.

MR. TAVARES: Okay, anymore comments, input, questions? Online, anybody? Telephone? No? Okay, well, thank you very much. I think we beat this horse to death as far as scenarios. But we are waiting for your input and comments. We are almost there, we have only two more speakers that are going to go really quick. Matt Layton is going to talk about localized impacts and risks for interconnecting new power plants. And then, at the very end, Ivin Rhyne, of our Electricity Analysis Office, will actually summarize the day for us. So, Matt.

MR. LAYTON: Good afternoon. I'm Matt Layton, I manage the Engineering Office, feel free to forget everything you've learned for the last six hours. I work in the Siting Division, I don't work in the Electricity and Natural Gas. Two issues have come up in siting cases that the Commissioners have asked us to look at and they're related somewhat to the San Bruno incident and also another accident. So, I've been added to the Electricity and Natural Gas IEPR Workshop, and so I'm here to talk about two very small short brief issues.

The Energy Commission in the Siting Division, not the Electricity and Natural Gas, it's Siting and Transmission and Environmental Protection Division, we are responsible for licensing or doing the environmental review for power plants 50 megawatts and greater, and that's thermal power plants. Obviously, we look – this is a functional equivalent of CEQA, so we look at pertinent facilities or ancillary facilities, these would include the linears, the natural gas pipeline, the electricity transmission pipeline, the water pipeline that go off the site. Obviously, there have been concerns raised about the natural gas pipelines, and so we've been asked to consider that in our environmental analysis. However, CEQA is pretty strict about looking up to the point of the first interconnect, whether it's transmission, or a water pipeline, or a natural gas pipeline. So, we generally do not look beyond the point of interconnect when we're looking at issues associated with the gas pipeline. But, in trying to assess the risk associated with just the interconnect pipeline that connects the power plant to the transmission pipeline, we do look at what's out there. And what's out there is an existing regulatory infrastructure that's pretty well developed and pretty well regulated, and so we try not to step across that boundary and assist the PUC or the Department of transportation in how they take care of environmental issues or safety issues associated with the gas pipeline.

I'm sure most of you are familiar with the Regs that apply to natural gas pipelines, and again, this is just a quick background on how we ultimately assume or calculate the risks associated with this new interconnect pipeline, some of the LORS, we call them LORS, excuse me, Laws, Ordinance, Regulations, and Standards, they've evolved over time, they have modernized with modern materials, modern techniques, some of which include improved welding requirements. Ruben and I didn't get this all straightened out before I came down here. Obviously, another cause of pipeline failure is damage from construction or excavation equipment, so Codes now require very clear marking, we would require the same in the pipeline that we're licensing.

Seismic requirements have been upgraded. One of the concerns we have about interconnecting new pipeline to the existing pipeline, you now change how it responds in a seismic event, you now put a fixture, a point, holding that pipeline in place when you have to add a new pipeline to the existing pipeline. We have found that the seismic Codes have worked much better, there's been a couple of earthquakes up in Japan prior to this most recent one and also an earthquake in the northwest and, again, the modern pipelines perform much better. We're always interested in what's being built in the area, so the land use, the population density, and also the encroachment over time. What's built around the pipeline dictates the rating or the classification of the pipeline and will then dictate its construction and design criteria.

Obviously, regulations do change as a result of accidents. We believe that the investigation going on in the San Bruno incident may result in some changes to the Regs and, for example, in 2002, the Integrity Management Program is now being implemented, it's being implemented over time, it requires advanced inspections, risk assessments, and mitigation measures of any pipelines that travel through high consequence areas.

So, back to the Energy Commission and our licensing requirement. So we're trying to assess the risk and, again, risk is the combination of the likelihood of an accident occurring and the consequences of that accident. And we're not trying to bring risk down to zero, we're just trying to minimize risk, keep it acceptable. So we are evaluating the pipeline, we look at the pipeline and how it's going to be constructed and operated, again, whether or not it's a high consequence area will dictate what standards it's built to. Special situations may require modifications. A couple years ago, or actually about 10 years ago, SMUD was in here, they had about a 60-mile pipeline that was proposed for about four of their power plants. Part of the pipeline went past the rail line. We required a cement cap or concrete cap over that to protect it. So, as we're going through this, we're trying to make sure we, again, minimize – reduce risks down to an acceptable level. One of the tools we use is this Potential Impact Radius. So, this issue came up in a couple siting cases recently and there was a lot of debate about how far upstream and downstream at the point of interconnect you should look. We don't believe, 1) there's any physical effects that will go upstream or downstream where you interconnect a pipeline, but, more importantly, we were trying to be conservative, so we did assume that, for example, if the main pipeline that you're connecting to did rupture, what might be the potential impact radius? So, 1,000-feet seems like a very conservative number for the effect of a rupture of a pipeline; again, it depends on what's located up above ground, obviously, is of significance, it's important to the people that are there. So, we only look at the point where it interconnects, we don't see any physical changes upstream and downstream. If there were physical changes, if there was a compressor that was installed, or pipeline was resized to handle the new flow, our CEQA analysis would carry over to that side of the interconnect point and we'd also do the environmental review of the new pipeline.

Another issue that came up, California does have – anticipates a lot of renewable generation to be on line in the next few years. Questions were raised during some of our siting cases about how the pressure cycling due to the increased use of this variable generation would affect the pipeline. We believe that, 1) the pipeline already does cycle and is designed for that, and we have found some studies that indicate that pressure cycling can at least lead to increased failure, but, again, that's over 170 to 400 years, we don't think that really will play a significant part in whether or not these pipelines fail within their lifetime.

And the last issue which also came up in the recent siting cases, there was a serious accident back in Middleton, Connecticut, the Clean Energy Project, they were cleaning out the gas line that came from the transmission line, six people died, numerous workers were also injured, and then they practically destroyed the power plant. In reviewing that, the Chemical Safety Board decided that using flammable gas is an inherently unsafe practice and should be prohibited. Commission staff agrees and, in current projects, we now prohibit the use of natural gas, or flammable gas, in the cleaning of that new interconnect pipeline. Obviously, if the owner doesn't have any options, it needs to use the pipeline gas to clean the pipeline, the new pipeline, we could allow it, obviously, though, we would recommend that they follow the procedures. It is believed that the Middleton accident was due to operator failure. There are plenty of alternatives, whether it is compressed gases, or steam, or a mechanical pig can also clean the pipe. And I have attached a few references that I referred to in my very brief talk. Again, these issues came up in a couple siting cases. The members of the public have been asking us about us, and so have our Commissioners, so we're going to put these ideas forward in the IEPR, it's a very brief section and somewhat related to what you sat through for the last six hours. If you have any questions, I'd be happy to answer them. And you have until May 3rd to provide written comments.

MR. TAVARES: Any questions, any comments? Anybody online? Telephone? No? Okay. I think what we're going to do now, I'm going to open the phone for any comments that anybody might have now. Does anybody want to submit comments now or speak on anything? Nobody does? Okay, well, we're going to get to the last section here of this long day and Ivin Rhyne from our group will speak and summarize the day for us. So, Ivin?

MR. RHYNE: We're almost done, I promise. I'll be brief. All right, so I want to first of all – again, my name is Ivin Rhyne, I manage the Electricity Analysis Office; Ruben and his team work for me -- and I just wanted to kind of close out the day, I'm not on your agenda, but I wanted to kind of bring things full circle.

So, first of all, thank you to all of the hearty souls who sat through the day and a lot of this information. I know that, to some extent, it can be a little bit overwhelming, but there's a lot of good information here precisely because this is a difficult task that we've undertaken. And to look at a very complex system and to figure out how best to provide information about what may happen in the future, so I wanted to just kind of reiterate a little bit what our goal here is, and it's not to predict what will happen, but instead to provide information about what could happen under a certain set of plausible conditions. And we talked about both the reference case as Dr. Medlock refers to it, but also some scenarios that provide us the ability to kind of imagine what different futures could look like, we talked about stressing certain conditions, we talked about policy choices and different things that we can do, and trying to capture that in a model is not an easy thing to do because, obviously, these models are built to try and give us a balance between some sense of, you know, precision or accuracy, but also to be flexible. And so you can't anticipate everything that's going to happen, or every potential, "Well, what if this happened? What if that happens?" And so, as these conditions vary or change, the calculated prices will change, and really what we're trying to figure out is how big are those changes likely to be, and what could they look like?

So, let me give you some information just as a visual context here, and I'm not providing this necessarily to you because there's some preliminary work going on here, but I'm just going to give you a sense of context here. So, there are three lines plotted here that all look relatively close together and these are nominal natural gas prices over the next ten years or so. And the three lines actually represent the forecast put out, the initial forecast, preliminary by the Energy Information Administration, the Rice Reference Case, and then a future strip, one obviously if you follow futures, they change from day to day, this is a recent future strip, but as you can see, these three sets of values, these three sets of nominal prices, are actually relatively close together. And so the normal person's assumption would be that, with those three sets of prices close together, well, then they must have really similar underlying assumptions, they should be describing roughly the same future. But that would be an erroneous assumption. They reach their values through very different sets of assumption, and so it's important always to put any kind of price projection in context, and that context is why we're here today, we're trying to figure out what kind of context to put around, what kind of assumptions should be made, what types of levers within the model should be adjusted so that the values that come out of this are actually useful and helpful to both the policymakers here at the Commission, but also to stakeholders who are here in the room, and also online.

There are some values here, for example, in the Rice World Gas Trade Model, just as input values, seed values, it assumes a 5,000 gigawatt hour electricity demand, and we have AEO's 2010 forecast assuming 4,800 gigawatt hours, that's actually a relatively large difference in terms of energy usage. And so that's just an example of the fact that there's a lot of information that goes on inside of these things, and so we're trying to be very transparent about where we're going with this.

So, all work that we've done to date has been leading up to having an open and transparent dialogue with stakeholders. That dialogue got, I hope, started today, although I think some of us will need some more caffeine to get home from here. But this work is preliminary. The purpose of the workshop is really to solicit input and, as you may have heard once or twice already, we are looking for comments by May 3rd. And what we're really looking for is your feedback and your input, that's really critical to this process. What buttons should we push? And how hard do we need to push them as a way of saying, “What adjustments do we need to make inside the model, and how large or how small should those adjustments be to capture the plausible range of prices?”

So we’re asking for comments by May 3rd, but it’s really okay to submit those early, and we emphasize that because we’ve got a team who are really working to kind of figure out how to translate all of this information into actual values and capture that story, that context, and that’s a difficult time-consuming effort, and so the earlier we get your comments, the earlier we can incorporate that into our thinking, we’re going to be running these cases pretty much through the entire month of May with an intense internal review in June, and we’re going to come back to you and share those results, as well as the broader thinking of what we think the natural gas market looks like, or could potentially look like, in the future when we come back and have another workshop in July. And so, with that, I’ll open one more time, are there any questions or comments that anyone here would like to share before we close out the day? Anyone online? All right, so with that, I want to thank everyone for attending. Thank you all very much. I hope everyone travels home safe and have a wonderful day.

(Adjourned at 3:11 p.m.)