STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	)
Preparation of the 2007 Integrated	)
Energy Policy Report (IEPR)	)
	)
Inputs, Assumptions and Issues for	) Docket No.
the Natural Gas Assessment Report	) 06-IEP-1D
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, MARCH 26, 2007

9:10 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

James Boyd

Jeffrey Byron

STAFF PRESENT

Ruben Tavares

Lorraine White

Leon Brathwaite

Michael Magaletti

James Fore

Angela Tanghetti

Mike Purcell

Bill Wood

CONSULTANTS/PRESENTERS

Robert Logan
James Jensen
Consulting Energy Economist

Catherine Elder
Youssef Hegazy
R.W. Beck

ALSO PRESENT

Alvin Pak
Sempra Energy

Robert S. Cowden
Pacific Gas and Electric Company

Jill Scotcher
Pacific Gas and Electric Company

Suzanne Phinney
Aspen Environmental Group

I N D E X

I N D E X

P R O C E E D I N G S

9:10 a.m.

MR. TAVARES: My name is Ruben Tavares and I'm part of the staff of the Energy Commission. This is a staff workshop that we are preparing for you here on the natural gas assessment for the 2007 IEPR.

Now, we focused our -- some housekeeping items. For all of those of you either on the web or here present in the room, this workshop is tape recorded, and also webcast on the internet. Anybody can make phone calls and we have a free line, free toll line. It's 1-800-621-3587, and the passcode is natural gas. Co-leader, Ruben Tavares. R-u-b, like in boy, -e-n, Tavares, T, like in Tom, -a-v like in victor - a-r-e-s.

Those on the phone please identify yourselves whenever you call, and please keep your telephone on mute while waiting.

For those present in the room, restrooms and telephones on the patio to your left as you get off of the hearing room. Coffee and beverages up the stairs on the second floor. And, also, please silence your cellphones.

There's enough agenda and copies of all

the presentations as you got into the hearing room. We're planning to run this workshop for about five, six hours. We think we can end by 2:00, but we'll see how the workshop proceeds.

When you make a comment or want to ask a question please go to a microphone so that everybody can hear, and we can record for the record.

Again, this is a staff workshop but we have two Commissioners. Commissioner Jim Boyd is present, and Commissioner Jeff Byron is also present. Commissioners, would you like to make any initial comments?

COMMISSIONER BOYD: It's your workshop, Ruben, go for it.

MR. TAVARES: Commissioner Byron?

COMMISSIONER BYRON: No, thank you very much.

MR. TAVARES: Okay. I would like to introduce Lorraine White; she is the program, actually the IEPR Program Manager. And she's going to make some presentation to describe how the natural gas assessment fits into the 2007 IEPR. So, Lorraine.

MS. WHITE: Just a moment, I'm going to

pull up my brief presentation. Thank you.

The natural gas assessment is one of the critical components of the Integrated Energy Policy Report. In addition to doing an assessment of a natural gas system supply, demand and price, we also do an assessment of the petroleum supply, demand and price, electricity demand,supply and price. They're all very much related.

And so as we move forward in this proceeding and look at the natural gas market consumption and future issues. what essentially we find out about the natural gas system in the state very much feeds the other energy systems in California. So one of the integral parts of the overall IEPR.

Ruben's already gone through a lot of the logistics and participation information. I want to also let folks know, predominately those on the phone, that all of the information about the Integrated Energy Policy Report proceeding, including the natural gas assessment, can be found at the Energy Commission's website, www.energy.ca.gov.

In particular, the statute requires that the Energy Commission, for various energy components that the state depends on, develops an assessment and a forecast of supply, demand and price.

We develop these assessments and forecasts based on inputs from a variety of sources, whether they're utilities, vendors, other market participants, consumers, things like that, in order to formulate as comprehensive an assessment and look to the future as we possibly can.

As we look at the issues and develop policies, we not only engage the market participants, but we also consult with other agencies, whether at the federal, state or local level.

From all of the information that we gather and all of the analysis that we do on that information we develop and recommend key policies that we think are necessary to insure a reliable, cost effective system to meet the state's needs.

The statute requires that we do this every two years, and in the intervening years we do an update of key particular issues. This particular proceeding, the 2007 Integrated Energy Policy Report, included a 2006 update that was restricted to predominately two topics, the renewable portfolio standard and the issues of land use and energy.

For the overall proceeding we issued a scoping order on the first of August. We had initiated the proceeding back in May, but the first part of the proceeding is always gathering information and trying to refine the scope for the remainder of the analyses and staff's efforts, as well as the scope of the Commissioners' considerations for policies.

Starting in the fall and going actually now probably through April rather than March, we're collecting as much information as we can to educate ourselves, to incorporate into our analysis and to be part of the consideration of our record.

We expect that we will produce the preliminary analysis and some of the initial results starting in February and going through May, June timeframe. Maybe even in July, depending upon the scope of the issues and the types of analyses required to fully explore them.

Staff will start publishing their results and their issue papers starting about

June, going certainly into July.

During all this time, of course, we want to engage parties and keep them involved in our deliberations and analyses and development of policies. Of course, throughout the proceeding we will be holding workshops and hearings, whether staff or Committee workshops, to try and get as much input, engage people in as open a process as the Commission can possibly get, so that we can fully vet any kinds of assumptions or framework for our analysis as possible.

The Committee is currently planning -- by the way, the Integrated Energy Policy Report Committee is the Chairman Jackie Pfannenstiel and Commissioner John Geesman. For our Natural Gas Committee that is made up of Commissioner Boyd and Commissioner Byron.

A lot of what we're doing in the Integrated Energy Policy Report proceeding engages most, if not all, of the Commissioners, throughout the entire proceeding. So you'll see a lot of joint workshops and joint events so that we can fully cover the issues.

We expect to produce a Committee draft report in September. In the September/October timeframe we'll be holding workshops on this to bring together and finally resolve all of the outstanding issues; and refine our policy recommendations.

And we currently expect to issue the final 2007 Integrated Energy Policy Report at the beginning of October so that we adopt it by the full Commission on the October 24th business meeting. This allows us to meet the statutory requirement of transmitting the adopted report to the Governor and the Legislature by November 1st.

As I said, this is a rather involved and engaged proceeding. There's going to be lots of information developed. We have dedicated a website on our main webpage for this whole proceeding. You can access information, whether presentations for workshops, reports, information on assumptions, analyses, looking at previous reports that we have done, all of that can be accessed from the Commission's website.

If you have any questions of a general nature, they can always be directed to me; including who do you need to talk to on specific details.

For the natural gas assessment, Ruben

Tavares would be your main contact. His information is not only available here on this slide, but on the webpage, in the notice, and specific questions about what we'll be discussing today can be directed to him.

If there's any questions on the overall proceeding I'd be happy to answer them now.

All right.

MR. TAVARES: We have a full agenda this morning. The way we're going to proceed, we're going to have a series of presentations by staff. And after each presentation we will open the forum for any kind of questions or comments the audience may have.

We also have two of our contractors who are helping us in this natural gas assessment, and I will ask them if they have any comments or questions in regards to the presentations by the staff.

So, what is the purpose of the workshop? The purpose of the workshop is to receive comments, suggestions and any kind of an input from the public now that we are engaging in a new natural gas assessment report for the 2007 IEPR.

The staff will make a series of

presentations on the model that we use in order to forecast supply, demand and prices. It is the North American Regional model. And we're going to have a presentation on the model this morning from the staff.

Also we're going to have presentations on inputs, assumptions and content in general for the natural gas assessment report.

In the past natural gas assessments we have focused mainly on a point forecast. This time around we're going to have a lot more discussion and a lot more content on the process, on the inputs and assumptions that we use to do a natural gas assessment for the State of California; and also we're going to focus on the uncertainty of many of the inputs and many of the assumptions that we use, again for discussion and for inclusion into the natural gas assessment.

staff is planning to use a model, the North American Regional Gas model, for estimating, actually running what we call a reference case. This reference case is going to be used as a departure for additional analysis that we're going to be including in the natural gas assessment report.

Staff is also planning to use NARG to run four different sensitivities. We are wanting to know how sensitive natural gas prices are to other prices. So, we're going to be running four different sensitivities this time around. In addition to that we'll be open to any kind of suggestions or comments.

With that I would like to introduce our first presenter this morning. Her name is Katie Elder. She is from R.W. Beck and Associates. And she's going to make a presentation on the overall approach to the natural gas assessment.

(Pause.)

MS. ELDER: I hate standing behind podiums. I think (inaudible) when they stand behind one, and they just make me tense. So, I've got two pointers, then? All right, one pointer.

I'm Katie Elder. I'm with R.W. Beck. I'm going to talk a little bit about what we're doing different in the IEPR and for the natural gas assessment. Let me introduce to you my colleague back here in the back, Dr. Youssef Hegazy, an economist with R.W. Beck. I'm Beck's natural gas market expert.

And, of course, when I stand up here I

can't change the -- can I? All right, good, I got help.

The Commission decided to use a decidedly different approach with the natural gas assessment this year. And what we kept trying to do is to use the reference case and the modeling that staff worked so hard at, and use that as a reference case, as a point of departure, a take-off point for having a more robust discussion particularly focused on uncertainty. In the natural gas business we think that there is a lot of things, no matter how good the model is, no matter how good your assumptions are, no matter how hard you work at it, the world will turn out to be different. And that's the reality of it.

So, we're going to try to capture those things that will be different than what we put into the model. And that's part of the purpose of this workshop is to gather input and ideas about those things that we ought to consider that will be different than the model assumptions that we use, that we need to make sure get thought about as we think about how the natural gas future could unfold.

So, we've got staff preparing a

reference case; they're using the NARG model that they use so often and so well. We expect that real prices will actually be different.

We have observed that there are a lot of folks who are involved in forecasting natural gas prices. A lot of really smart folks involved in forecasting natural gas prices, consulting firms, government agencies, what-have-you, across the U.S. and across Canada, and probably all around the world. And probably nobody's got a really great track record at it.

No matter what we seem to do something unexpected always happens to derive a different outcome. So that's what we're trying to focus on as we use the reference case as a take-off point for discussion, and identify the factors that will cause higher and lower prices around that reference case.

We're not saying that the reference case is what we think will happen in the world, that's not what we're using the reference case to do. We're using the reference case to frame our discussions about things that could happen around that reference case. And that we want people to be aware of and to think about.

R.W. Beck's role in all of this is really to facilitate, facilitate with a capital F, that discussion of those factors, and to augment staff's efforts and work alongside staff. So we're not replacing them in any way.

We're going to skip the next page in the package and come back to that a little bit later, but let's just have the little bit -- we thought it would be good to talk about things in the market that are different since the last assessment.

There's a lot that's changed actually if you stop and think about it. First off, we've got the reality of prices that have stayed at the $6 and above level. Two years ago you might have thought it was a temporary blip, it wouldn't maintain. Now you've got that in the aftermath of the hurricanes and a number of other market developments. You can see that that impact has been sustained in a couple of year period.

The other thing, and it seems like for at least the last 15 years that I can think of, everybody will talk about prices and reference volatility and that prices are volatile. Well, it also looks like prices are getting more volatile.

That volatility increases over time, or appears to have increased over time.

We've seen oil prices that blipped up in the summer of 2005. A lot of folks probably argued it was temporary. You saw articles on the front page of The Wall Street Journal talking about OPEC setting a new price, $40. We've stayed over $60 for the bulk of the last two years. So you've not only got natural gas prices above 6 bucks, you've got oil prices that have stayed about $60 a barrel.

And yet, at the same time, aggregate demand for natural gas is still around 22 Tcf per year. We're going to show you some graphs later that are kind of interesting about that, because as we talk about demand being relatively flat at 22 Tcf per year, the reality is that there's been a dramatic decline in industrial demand, and a dramatic increase in electric generation demand. So if you just look at that aggregate number you don't see the dynamic that's happening behind that.

The western bases differential appear to be very large after Hurricane Katrina. There were times and places where east versus west, or Henry

Hub versus the west might have been $3, $4 per mmBtu. Even going into last winter you saw differentials between Henry and the California border of maybe a buck-fifty per mmBtu. That seems to have normalized back to a level that's roughly similar to before the hurricane period.

We have got some additional discussion about security supply issues. One of the things that folks learned in the aftermath of Hurricane Katrina was that some of the facilities in the gulf were not as impervious to interruption as we might have thought. And we saw some pretty dramatic impacts there to gathering systems, to platforms that disappeared. I think there are still a couple that have never been found. And so we learned that we've got maybe a little bit more at risk there than we thought.

And then there are people who are worried about the rise of energy nationalism or perhaps a potential re-rise of energy nationalism, particularly when they look at what the Russians are doing with a couple of activities at Sakhalin, at the other Arctic peninsula whose name I'm forgetting, north of Minsk. And later that will come to me what that name is; I can't remember what it is right now.

But you've got Prime Minister Putin talking about potentially a group of countries getting together to try to manage what's going on with energy supply to different countries. And some people who think that maybe he's come a little too close to using the "C" word.

We've got some LNG obviously -- terminals, obviously under construction, about to begin service in 2008. That's a big key change. And we've got huge emphasis now on control of greenhouse gas emissions and carbon that's going to have an impact on natural gas demand.

So, a pretty long list of things that have changed in the last couple of years. Now, we've put together a list of things that we think, besides those things that have changed since the last assessment, a list of things that we think make sense to pay attention to as we develop this next assessment.

We think about the assumptions that staff is using in the modeling that we're going to get results from. And think about things that could go different around that. What could change around that.

And we're going to spend much more time as we look at each of the sections, each of the components of the assumptions that go into the NARG model. We're going to think more intently about differences in potential assumptions around the reference case.

Here are just some ideas that occurred to us as we thought about this. We've got new capacity in the form of at least Rockies Express moving gas from the Rockies eastward. That will have an impact certainly on the west and California.

We've got a dispute, or some disagreement might be a better word to have used here, between the CPUC and SCAQMD over what the Wobbe Index ought to be. And there's at least some concern that that number gets set too high we could end up excluding some gas supply from California that we would otherwise have access to. That could have an impact.

We're going to see created here pretty quickly a Citygate in southern California. There's certainly some folks who think that that probably won't have much impact, but it may move the price point just a little bit. We'll get more information, more transparency, but we shouldn't see a lot of change beyond that. We'll see about that.

There is at least some possibility that we might see something, a repeat of something that happened in the gas business, and we'll show you a graph later that will illustrate this to you, but that we might see something that happened in the gas business in like '70s and 1980s where we actually saw significant demand destruction. And that if you actually, and I don't mean the word destruction is a bad thing in that context, either.

But you might see a significant reduction in energy matters. There's a wholescale broad effort to reduce greenhouse gas emissions that result in a reduction in energy consumption. And that could force natural gas demand down.

At the same time the offsetting argument is that there could be an increase in natural gas assumption to the extent -- an increase in natural gas use to the extent that we use gas to replace coal-fired burns in coal-fired generation. That's kind of going in opposite directions.

We're worried about the oil market and

what goes on with the oil prices. Will they ever come down below 60 bucks a barrel again? I mentioned that energy nationalism and the context of supply security. It's really kind of the same issue.

There's also some sense about the relationship between storage and volatility of natural gas prices. FERC Chairman is very often heard to say that more storage in the U.S. would reduce price volatility. And there's some research actually going on under the Public Interest Energy Research program to address that. A number of different consulting firms and how -- look at that issue. But we're going to keep that in the back of our mind.

And the, at the same time, last but not least, it looks like a number of the major oil companies who have gone offshore in the last six, seven, eight years are coming home. Shell and bp are spending upwards of, I think each of them has programs through parts of the U.S. that would cost them over $1 billion in investment. So that's a significant change in where they're investing their dollars. And where the oil companies, the major ones in particular, invest their dollars is worth watching.

So, we want to emphasize that as we walk through all of the different sections of the report, and we talk about the reference case assumptions, and we talk about alternatives, we're looking for input. Comments, suggestions are more than welcome. We're actually anxious to get them. We want to hear what people think about the key uncertainties. And how we craft the discussion around the reference case.

So, I'm going to turn this over now, I think, to Leon, right? And we're going to be somewhat interactive in sort of handing the microphone back and forth, and being very informal talking about the reference case assumptions, and then talking about alternatives.

So, hopefully, first off that will keep you entertained on a Monday morning. And it will hopefully actually also help us get better results.

MR. TAVARES: Thank you.

MR. BRATHWAITE: Good morning, everyone. I'm Leon Brathwaite; I'm in the natural gas unit. I am going to talk a little bit about, well, one of the tools that we are using here at the

Commission in this cycle is the World Gas Trade model, which includes the North American Regional Gas model, which Katie referred to a little while ago. So if you hear me use the WGTM, it stands for World Gas Trade model. And it is -- consider it worldwide version of the North American Regional Gas model, which is what we call NARG.

Okay. The World Gas Trade model has four levels of disaggregation. We have super regions, we have regions, sub regions and activity nodes.

Now, we have two types of sub regions -- super regions in the model. We have a geographic super regions, like Africa, Asia, Europe, Latin America, mainland Asia, middle east, North America, Pacific Rim and Russia.

We also have super regions that are based on their process characteristic. For instance, like the world liquefaction, the world LNG regasification, world shipping and world oil. These are all super regions within the model, but they are based upon their characteristics, not upon some geographic location.

Now the super regions represent the highest level of aggregation within the World Gas

Trade model. The model divides these super regions into regions. For example, in North America the North American super region has three regions, the United States, Canada and Mexico. And this portion of the model, the North American portion of the World Gas Trade model is our commonly referred to NARG model.

The model then goes further and divides each region into sub regions. And the United States has three sub regions type. We have supply where we have 40 supply sub regions, or supply basins. We have demand, we have 54 demand sub regions or demand centers. And then we have transportation, we have 80 -- I'm sorry, that should be -- there's a problem here, I'm sorry -- that should be 33 transportation sub regions within the model.

Now, at the lowest level of aggregation the model divides each sub region into activity nodes. And the activity nodes is where we place our data. And there are five types of activity nodes that we use. We have supply resource, allocation, processing, transportation corridor -- and I'll speak about that, what it means, here shortly -- and demand, and the demand can be elastic or inelastic.

Now, the supply resource contains what was known as our supply cost curves. And this determines how much natural gas is produced and at what cost.

Then we have the allocations. This is where the model makes it calculations and it determines the allocation of natural gas at the various hubs in terms of direction and price.

then we have processing. The processing loads could be a gathering facility, a liquefaction facility or an LNG regasification facility.

The transportation corridors. Now, we have two types of transportation corridors within the model. And the model does not treat them any differently. What is important, though, between those two is that we represent the cost properly. So a transportation corridor can either be a pipeline which links a supply basin to a demand center. Or it can be a ship that links an LNG liquefaction facility to an LNG regasification facility.

Then we have our demand nodes. And the demand nodes can be elastic or inelastic. If it is elastic then it would be sensitive to price changes. If it's inelastic then it's not. And we use both types in the model, and I'll show an example of that shortly.

This is a schematic of a supply sub region. And down here, these are supply resources, and this is where we'll have our supply cost curves. And Mike will be talking about that, Mike Purcell, who's sitting here in the audience, will be talking about that here shortly.

Right here is one of our guiding facilities. It's a processing node. And this is one sub region, one of many sub regions within the model.

Here is a transportation sub region. And we have, these are ships moving gas from a liquefaction facility into a hub. In this particular case it's the Caribbean. I'm from the Caribbean, just a bias, sorry.

And then from the hub you can move LNG out into North America or to Europe somewhere. But this is just an example of a transportation sub region.

This is an example of a demand sub region. Now these dark blue nodes here, we have four of them in this particular case. These dark blue nodes are our elastic nodes. And this one here is power generation, which is inelastic. Now, Jim Fore will shortly be telling you a little bit more about what we put into those nodes before we decide to run the model.

And what is important to note here is that we try to represent all of our demand sectors. We have residential, commercial, industrial chem, industrial non-chem, and power generation. All of these are represented within the model.

Okay, so the World Gas Trade model and about its convergence, how do you do that. The World Gas Trade model is a general equilibrium model. And for it to reach convergence, which is what we are trying to do here, for it to reach convergence, the model seeks a simultaneous equilibrium in all sub regions in all time periods. And when it does that we can say the models converge; and from there we can extract our information or extract our results.

And with that I will close here and I will open the floor for questions and comments. Now, I must say that the model is a very dataintensive animal, for want of a better word. And I have not covered even one-tenth of all of the information that we need to run this model here. Okay, so this is just a brief presentation to just give you an outline of one of the tools that we'll be using in this process in this cycle of the natural gas assessment report.

So, any questions or comments I'll be glad to handle them at this point in time. Mike.

MR. MAGALETTI: Mike Magaletti, --

(Pause.)

MR. BRATHWAITE: Make it hard to just ask a question, don't they?

MR. MAGALETTI: Yeah, it is. I think it'll discourage me in the future.

Mike Magaletti, California Energy Commission, Public Interest Energy Research program.

On your supply sub region slide, would you mind going back to that?

MR. BRATHWAITE: Sure. How do you go back on this thing? Oh, there we go.

MR. MAGALETTI: I think it was page 9.

MR. BRATHWAITE: There we go.

MR. MAGALETTI: It was the depiction.

MR. BRATHWAITE: Yes, this one?

MR. MAGALETTI: Yes. It caught my eye, this CO2, North American CO2 pricing node. Could you explain that?

MR. BRATHWAITE: Well, within the World Gas Trade model there are several units or algorithms within the model. And one of the things the model tries to do is capture emissions that are produced as a result of the production of natural gas. That is what that represents, that pricing node.

Now, we do not use that very often. This is probably our first that we are really going to be looking at that a little bit. But, that portion of the model is not well developed, and it's something that we will be looking at in the future.

But it is a pricing node that tries to capture CO2 and other greenhouse gases that are produced as a result of the production of natural gas, yes.

MR. MAGALETTI: So when you say you don't use it much, or it's not fully developed, do you mean you don't have emission factors, or you don't have prices?

MR. BRATHWAITE: We do have emission factors and we do have prices, but I'm saying the algorithm is not fully functioning, I should say.

MR. MAGALETTI: Okay, thank you.

MR. BRATHWAITE: Questions? Yes, Al.

MR. PAK: Al Pak for Sempra Global. I have a question on the supply sub region, and maybe it's a question for Katie, as well, because she was talking about the potential impacts from the Rockies Express project being added that would move gas from the Rockies to eastern markets.

I was curious to understand if you were going to treat Wyoming as a single supply sub region. Based on what Katie said it seemed that you might be doing that. And we view the western part of Wyoming that's served by Kern to be different from the eastern region that's served by Rockies Express.

So, if you could explain if you have a sense of how you see that interaction working and how you are modeling it for the purposes of the IEPR, I'd appreciate it.

MR. BRATHWAITE: All of the supply in North America is represented within the model. Now, specifically you are asking about eastern

Wyoming?
MR. PAK: Yes.
MR. BRATHWAITE: It is represented in the model.
MR. PAK: Is that included in the Kern basins, as well?
MR. BRATHWAITE: Yes, --
MR. PAK: As one basin?
MR. BRATHWAITE: Well, it is connected where it can be transported by Kern. You may two, three or four supply regions all connected into one allocation, supply allocation.
MR. PAK: The answer's no?
MR. BRATHWAITE: I wouldn't say no. I think the answer is yes, they are --
MR. PAK: But I mean there's --
MR. BRATHWAITE: Mike, you'll have to go to the lectern.
MR. PURCELL: This is Mike Purcell; I work for the gas unit, but Wyoming's broken up into more than one region. And it's not just, you know, all the gas in Wyoming doesn't necessarily just to Kern or have a potential to go to Rockies Express. It's broken up into several supply nodes. So, you know, it's disaggregated. It's

not a big lump.

MS. WHITE: If I could just interrupt real quick. To help facilitate getting your questions on the transcript, as well as making it easier for us to discuss with you these, I'd like to invite folks who are likely to have questions to come sit at the round part. And that way you don't have to keep getting up and sitting back down and all that kind of stuff. And it allows us to get everything on the transcript that we need to make sure that we follow up with questions that we may not be able to answer fully to your satisfaction right now.

So, and in particular if there's a couple of the gas staff that could do that, as well, to make sure that we get the input on the transcripts that we need.

I'll start. Have a seat.

MR. PAK: I was hoping that was going to be my only question really.

MS. WHITE: Well, it's likely that in order to engage folks throughout the rest of the day, just make yourself comfortable.

MR. PAK: Then with the answer that we just received, maybe Katie could address what she thought the interaction between the new eastern market's access from the Rockies would be.

MS. ELDER: This has got a green light and I can hear myself, so it must be.

You know, Al, that was really a general reference to the concept, and I don't know how the modeling results are going to come out. But, at least there's an expanded link, if you will, between the aggregate or the disaggregate -- components that get defined in NARG; there will be a link that goes east.

I actually don't know, off the top of my head, how big that link is, or whether it includes phase two; phase one versus phase two of Rockies Express right now. We'll find that out when we get the model results back.

But there's at least some -- it seems reasonable to think that there might be some additional -- all else equals, but for this pipeline, some additional gas flowing, in general, from the Rockies eastward.

What we're going to be looking for is how much is that.

MR. BRATHWAITE: If I may add, Katie.

MS. ELDER: Yes.

MR. BRATHWAITE: Within the model there is a representation for the Rockies Express; and it will be allowed to expand after I think it's 2010 or something like that. So once the model results come back we will see how much flows will take place out of the Rockies going east; and we will also be able to see what expansions will take place within the forecast period.

Does that answer your question, Al?

MR. FORE: Let me see if I understand. You really were concerned in terms of what fields were going to be connected to the Rockies Express, the Kern or --

MR. PAK: Well, I was more interested in what you were -- preliminary modeling results, what you thought the interaction between the Rockies Express and California prices and supply.

MR. FORE: We'll have to wait for the output to --

MR. BRATHWAITE: Yes. Yes. And as soon as we have results we'll be able to answer that question more definitively.

Yes, Bob.

MR. COWDEN: Bob Cowden, PG&E. Just kind of a process question for either Katie or

Leon. Are we going to have a chance to look at or examine, not just have a discussion about the model inputs, but look at like the model topology and the basecase, kind of as a way to kick the tires about assumptions like Rockies Express, and, you know, what the transportation networks looks like for other areas in the model? More of a process question.

MR. BRATHWAITE: You want me to take that? Okay. Well, we did not plan to have the extensive network that we have right now in the model. We didn't plan to have it available today. But, Bob, I'll be happy at any point in time to sit with you or any one of your staff and go over our network that we are using in this round of the report.

But as you would know, the network for the World Gas Trade model, the North American Regional Gas model is quite extensive. So, in a workshop like this, an environment like this, it's difficult to show all of our links and connections and nodes and all that kind of stuff.

But, like I said, I'll be happy to sit with you or any one of your staff and we can go over the network at that point in time, if that's --

MR. COWDEN: Yeah, thanks.

MR. BRATHWAITE: Sure. Questions, comments? No? Wow, I feel good. Thank you.

MR. TAVARES: Thank you. We have also Dr. Hegazy. He's going to make an additional comment.

DR. HEGAZY: Good morning. My comment is a general comment about the type of structural model that the industry has been using to go the annual -- the typical annual price forecast, similar to the one that's currently used by EIA and a whole host of others.

The nature of such a model usually is -- it's a general equilibrium model. It's a model that equates supply and demand in order to reach the equilibrium marginal cost type of prices.

There is a lot of information, and especially when you're dealing with a commodity, there's a lot of information in the market that is extremely difficult for this type of models to capture.

For example, if you take any of this model, and NARG is not alone or exception of that, and you try to forecast the prices for say 2000, 2001, 2002, historical forecast, so you put all the actual demand and actual storage and actual weather and actual supply, chances are you're not going to get the actual prices that happened.

I mean the reason, again, is there's a lot of noises around demand, around supply and infrastructure events, and weather events, that is very hard to capture.

What this model are very good at is to provide the most important piece of information that the industry need, which is the estimation of the expected long-run marginal cost. The chances are, as we have seen in the last few years, especially when the oil industry and gas industry has shifted completely their paradigm, in terms of prices, in terms of the spare capacity that exists in the market, and in terms of infrastructure, and in terms of the globalization of both, chances are if you look at any forecast you'll find either it's above actual market prices or below market prices.

Market prices tend to be above marginal cost when there is a very tight market. Usually it tends to be below marginal costs like in the early 1980s when there's a bubbles in the gas industry.

With the commoditization of gas, as with oil in the past, a lot of other noises came in. The main point on the modeling is, and the new era, is uncertainty. Uncertainty about demand, infrastructure, supply, weather, political events and on and on.

And structural model has very hard time capturing that, because its very time-intensive, labor-intensive to do two or three or four sensitivities. In fact, with all of this uncertainty you need around 100 sensitivities in order to be able to create a probability distribution curve around the prices in order to allow yourself to study the policy impacts and the risk involved with each policy items.

There is two items in here I would like to strike out because they require a little bit of discussion which, Leon, one is about the elasticity issue, and the other one is about the monthly issue. It seemed that the model might have some -- the current model might have some capability to do that.

But the main point is the model is extremely useful in projecting the long-run marginal cost, which is a very valuable information. But the model, like every other model, has a very hard time taking into account market noises, uncertainties, major events like Katrinas or Russian oil nationalism, or the supply tight that exists right now in the oil market and in the gas market.

MR. TAVARES: Thank you. Any additional questions?

MR. BRATHWAITE: I would like to ask Dr. Hegazy about the fact that he said the models are very good at capturing the long run, or at least getting good estimates of the long run marginal costs.

Now, do you believe, Dr. Hegazy, that using scenarios on probable sensitivities to try to capture by probably not doing a point forecast, but doing like a range forecast for want of a better word. We can capture some of the noises that you are describing, which I have to agree, do really exist.

DR. HEGAZY: There's is two sides to this question. The answer is yes if you want to estimate a floor and a ceiling for the prices. So you can line up, and I will discuss this at the end when we talk about prices, you can line up all the scenarios on demand and supply and infrastructure and policy initiatives and what-have-you that you would think would bring the floor prices or the ceiling prices.

But in order to have that probable distribution, which I would believe most of the utilities and the market participants, market players who are active, especially in trading, use this type of techniques. In order to do that, just give you an idea, if you just look at supply, demand and say, infrastructure, on each one of them high, low and medium, three cases; and you're going to end up with probably 50 to 60 scenarios in order to capture all the intriguing, you know, interrelationship between all of these variables.

And to do 60 scenarios, as you know very well, in a model like NARG or any other structural model, you need a lifetime.

MR. BRATHWAITE: Thank you.

MR. TAVARES: Thank you. Any other additional comments? Anybody on the phone that would like to make a comment?

Okay. Next we're going to introduce the next speaker, Jim Fore. He's going to talk about the topic of natural gas demand. Jim.

MR. FORE: Thank you, Ruben. We're going to talk briefly about the demand side of the modeling and how we populate it with data, and where the data comes from that we put into the model.

And so, Leon has covered some of this, but we'll have to go where it's harder to stay in context and really follow through.

We have a demand structure that is in the model; and within that structure we have different demand sectors. And these sectors can be either inelastic or elastic demand in terms of their representation.

Then we, on the development of the elastic demand, we will go over the demand parameters, the functions and the assumptions that we used. And then I'll talk a little bit about the data sources that go into it.

And then in the inelastic sectors I'll tell you where we got the data from, and some of the reasons we use inelastic in those particular sectors.

As Leon mentioned, we have several levels of disaggregation from the world model down into the regions, sub regions and then what he called as the activity nodes. And we're interested in the North American side of Canada, U.S. and Mexico because of the integration of these markets through the distribution system.

But with the advent of potential LNG being used and forecasts of additional volumes of LNG coming into the U.S. that's why we had to go to the international model in order to look at the competition the U.S. would face in their demand for gas from Europe and Asia.

And so we have that entered to the structure in order to account for the demand that these areas will have, and the impact it would have on North America.

Now, as I mentioned, we have the United States and Canada are really the two main areas we looked at. Mexico doesn't really have the pipeline infrastructure that we have here in Canada and the U.S. for transportation of gas. But, it does take gas from the U.S. And with the LNG facility being proposed, will be receiving gas in Mexico, so we have to account for the impact it will have on our market. And we do have it in the structure.

Now, we have the structure broken down by states and regions depending on what we really want to look at. The west, we normally combine the states to look at the overall region that has to do with electric gas -- for the power gen, which is the WECC.

In the east we have looked at either as -- you can look at it at state level, or we have broken it down by the census regions where we would look at New England, mid Atlantic, south Atlantic, the east south central, west south central and the east north central and west north central which gives us the census regions in the west. And then we classify the Rockies and the Pacific coast.

Canada, we're really interested in the problems in the west in terms of how we break down and look at the model, because they have a demand that would impact the amount of gas that might be available to California. And that's why we're interested in the state level in the west because we're at the end of the pipeline, so the demand in the different states will impact the amount of gas that could end up to satisfy the demand in California.

Now, on the demand side we have 54 sub regions in the U.S., eight in Canada and 15 in Mexico. And the Mexico sub regions really are defined within the World Gas model is where they come from. The other ones we have done some combinations, modifications in order to get a structure that we feel fits the demand areas that we want to investigate.

Now in each sub region we divided into up to eight activities in terms of the demand for natural gas. And the level of disaggregation we use in these subregions depends upon the major activities the gas is being used for. All of them have some in common, some of them have some unique characteristics.

The model on the demand side we look at residential, commercial. We have industrial broken down into chem and non-chem; power gen. Then in Alberta the oil sands is a big user of gas, so we have that set out as a separate demand. California we have enhanced oil recovery which is a unique use for the gas, so we have that set out and separated.

LNG exports is only in there because we do export gas out of Alaska. And so it is a call on the demand, not big. And it may have been bigger if they (inaudible) to an export terminal, but it's just in there in order to account for what's really going on in the market.

Now, you've seen this structure. And what we're looking at is the gas coming into a citygate and then being distributed to the end use demands which are represented by those tombstones. And we have to put in a distribution cost in order to get to the different end uses such as residential, commercial, industrial and power gen. And I'll go over where we get that data at in just a second.

Okay. On the elastic demand are residential, commercial and industrial. We've developed elastic demand functions. And this is the result of comments we've gotten from the people that use the model. And they wanted to see some elasticity put into the model so that they can see the impact that price would have on the demand in these sectors.

So we developed a series of elasticity functions with the help of Dr. Metlock out of Rice University, and we are using these functions in order to get an initial demand for the model in all sectors over all time periods that are done really off balance sheet or out of the model, and then put into the model. And then the model will account for the elasticity of gas.

The inelastic, basically we take from forecasts that other people have made or ones that we have made internally. Some of the inelastic demands come from staff within the Commission and the other divisions. Some of it comes from information published by Canada in their evaluation of their gas market.

These are the elastic demand functions that we have, and we'll go over a little bit about the parameters that are used in them.

In the residential sector we have modeled this based on gross domestic product. We use the U.S. gross domestic product to represent all the regions in terms of estimating the demand. The population, of course, we have from the Census Bureau. We use that on the state level. In Canada we use it on the province level.

We use a forecast that the Census Bureau had made from 2000 to 2030 in order to get the state variation, so we don't use a common percentage all the way across the board. We have some states that are actually declining slightly in population, and some are increasing faster than others.

The heating degree days, we use a 15-year average for the states, and apply that then throughout the forecast period. We don't try to forecast, you know, a cycle of hot weather, cold weather. We just use the 15-year average.

Then for the price of natural gas we use the EIA data at the 2006 that's available on the retail level. We use that price in order to make our initial estimate of the gas demand throughout the forecast period. Then when it goes into the model it will come up with a different price estimate. And that's where the elasticity of price plays into effect in the model.

We have elasticity demands on those other three items, the heating degree days, population and income. And if you want to change that we can do it offline and then bring it back into the model. But to start with we make these broad assumptions for that in terms of the reference case.

On the commercial side we're using the income, gross domestic product, again, population and heating degree days and the price of natural gas. It'll have a different price because we'll be using the commercial price that EIA has published for the different states. The heating degree days, population and income will stay the same. But the coefficients are different between the commercial and residential equations. And so we are getting a unique set for the commercial as compared to the residential sector.

On the industrial side we have that broken into chemical and non-chem. And this is the area in which we use an industrial production index that's published by the government, and we use one for Canada that they put out.

We use a cross-elasticity for oil in order to account for the impact of people switching fuels. We use the EIA latest forecast for 2007 in their annual energy outlook. And that will be our reference oil price forecast.

And then the price of gas that we use, again, is the 2006 EIA average annual price that they have for industrial by the various states.

I will point out since we're using the EIA 2007 oil price forecast, I'm also using their forecast of the gross domestic product to get that forecast, so we -- the system somewhat in the model in terms of looking at a gross domestic product that is impacted by the price of fuel.

On the inelastic side we use power gen as inelastic and that's because it's actually forecast within the Commission for the WECC area by the Commission, by the staff here. And so we substitute that in and it's not allowed to change in terms of the price that would be forecast.

But we do an iteration process after we get a new, we give an initial price for gas or power gen. They run; we get it back. We do another run, we give them a new price, and so we go through a couple of cycles in order to account for the price elasticity that gas would have on power generation.

The Alberta oil sands, we use a forecast by Financial Energy Board in Canada. It's from their supply and demand forecasting put out a couple years ago. And we have looked at, you know, there's all sorts of comments about reducing the demand for gas in Canada for the oil sands. We could do that with a sensitivity, but we don't do it internally in the model. We use just the standard inelastic forecast throughout.

The same with California. We make an internal forecast of the amount of gas that will be used for the enhanced oil recovery project. And that stays inelastic throughout the forecast.

We have a couple of aggregated nodes such as the LNG that's been being exported for what, over 20 years. And the plant's very small. We just use that historical trend, just carry it throughout for the forecast period.

We do some aggregation in Mexico simply because of the lack of data. And so there is some more aggregation there as compared to the other parts of the model.

Our sources of data, of course, is from the Energy Commission, itself, from the EIA; the heating degree days comes from the National Oceanic and Atmospheric Administration. We use the Census Bureau. We use Natural Resources of Canada's information, Statistics Canada. And then any state and province data we may need we try and go there to pick up the data at the source.

Any questions? Bob.

MR. COWDEN: Thanks, Jim. Could you explain a little bit more how you iterate between the gas and electric modeling you have for the power gen demands? Kind of a sub-question, it seems like there can be a lot of difference in the WECC in generation resources that get dispatched based on kind of regional gas basis and regional gas prices. If they change you can have different dispatch of units. And I'm wondering how you capture that in your modeling.

MR. FORE: We have the WECC model fairly close. And we try and give the electricity people a gas forecast basically at most of the generating stations. Whether it comes off of the interstate line or whether it's coming off of the PG&E's line or trunkline or Kern.

We try and locate the power plants where we think they're taking gas from. So we have a forecast at each one of those power plants, depending on where it's pulling it off the line, whether it's a trunk line or whether it's at the citygate, wherever it is.

And that's the price that they start with. They run their model and they have prices of alternative fuels other than gas. And it then gives them -- Angela will cover this a little later on, but they then get a new demand for gas. And we put it back in our model; run it again; and give them another price for gas. Then they can do another iteration on it.

Usually we go two. If we have time we might go three, but normally it's two iterations is what we make.

But we try to have them located -- and that's one of the things you might want to look at in the structure, did we place those power plants, particularly in your system, where they should be in terms of what line they're pulling the gas from.

Any other questions? Okay, I'll turn it back to Beck -- or, Angela's going to next.

(Pause.)

MR. TAVARES: Next we have Angela Tanghetti. She's going to make a presentation on one of the inputs that we use for the electricity -- I mean for the natural gas demand for power gen. Angela.

MS. TANGHETTI: Just to follow up on your question about the price impacts in our model, when we do iterate back and forth. It does make a difference, the prices between regions as far as dispatch of generation resources.

I would say that price doesn't make a

big difference in our generation model as far as total overall gas demand, but the distribution between regions, it does have an impact. So that's what we see when we iterate back and forth if the price differences are there.

Okay, again, as Ruben said, I'm Angela Tanghetti, and I'm with the CEC's electricity analysis office. And I've provided my email address, and I think this is a good way to contact me if you have questions in the future about topics that we're discussing today. But, again, feel free to come up and ask questions today. Just in the future if you have additional questions.

Today I'm going to provide a quick overview of the method which the CEC Staff uses to develop a WECC-wide electric generation supply plan. But I notice that today I'm on the agenda and that this section was included under the demand. And this is, in fact, where our model simulation results fit into the natural gas supply and demand model.

But however, our simulation results are based on a future electric generation supply plan. And again, this is what I'm going to talk about today.

First beginning, how we gather information to properly characterize an existing system. And then how we include generation to meet future demand.

But first I kind of want to talk about why we've developed this supply plan. Currently our client is the Energy Commission's natural gas office. And they requested a forecast of natural gas demand for electric generation for use in their NARG model. I thought it was called another name today, as well.

But in order to do that we used the PROSYM model, which is a Global Energy Decisions regional electric generation model, to develop this forecast. I'm not going to get into a discussion about PROSYM today. On the next page I did provide a link to their website if you're interested in their model and what kind of model it is.

But, again, many planning groups operate in a similar fashion to this. They take output from an electric generation simulation model and feed it into a natural gas supply and demand model. So the iteration process is common amongst many entities that are doing natural gas planning.

And, again, we're using this -- we're developing this WECC-wide supply plan with the natural gas office as our main client right now. But in the past we've provided similar PROSYM type simulation results for the CEC's environmental office, the PIER office, air quality management districts, Air Resources Board and other entities. So we do this on a continual basis.

Again, there's a link to Global Energy, who we purchase the PROSYM model; so if you're interested in, you know, the model details you can go to that website.

But to begin this process one needs to make sure that the existing electric generation system is characterized correctly. And that is -- and what I mean correctly, I mean correctly for use in an electric simulation tool. And we've spent many, many, many staff hours on this existing system task.

And what I mean by characterizing it correctly for a electric generation model is for instance there may be a 100 megawatt generator in California that really only provides 75 megawatts to the grid; maybe the other 25 is used for some kind of onsite process. And that's what we want to capture in the electric simulation model.

And in order to do that we've, at least for California, we've prepared many subpoenas to capture this type of information. For regions outside of California we've really taken part in some regional planning groups such as SGG-WI. We've gathered a lot of this information about the existing system from contacts at SGG-WI, from CDEAC. And then just basically setting up contacts within those groups of how to model the existing system.

And, again, over the past we've received many requests to compare one data source to the other. And, you know, again, these are thankless jobs, but they aid you in characterizing the existing system correctly, you know. When you get a list of 3000 generators and why doesn't your bottomline match our bottomline, and you have to go through generator-by-generator, I kind of liken it to pulling weeds in my garden, you know. It's an important task and it's on a continual basis, but in the long run your garden really benefits from it.

And so we've really gone to a lot of

work over the past six years to, I think, adequately characterize the existing system because if you don't have the existing system characterized correctly, wherever you go from there it's just going to be wrong.

So, once we've kind of gotten that together as best as we think we can, to characterize in a simulation model, then we also pull in the demand peak and energy forecast. And for regions inside California we have the luxury of having the CEC's demand analysis office which provides that to us. And, again, the link to the specific forecast we're using is available there.

For regions outside of California we purchase this from Global Energy Solutions. And it's basically publicly available data that they've scrubbed for every region in the WECC. And when I say scrubbed, sometimes you just want to make sure that utilities aren't overlapping with other utilities' forecasts when you try to gather them in a simulation tool. So they've gone to the trouble of scrubbing it.

We verify the information on a spot-checking basis. So we feel comfortable with it, they're doing a reasonable job of those gathering those peak and energy forecasts.

The other input critical to the model is the natural gas or other fuel forecasts. And for the natural gas forecast we use the CEC's developed by inhouse staff. And that is a WECC-wide forecast. For the other non-gas fuel prices we, again, purchase that from Global Energy Solutions.

So, back to how we characterize the existing system. This is how the CEC Staff has chosen to model California. For regions outside of California we've again deferred to Global Energy Solutions as far as their characterizations of how the west is interconnected.

Again, for California, it's in a lot more detail than Global has originally provided, because we have access to a lot of information, the CEC Staff here, and just other planning organizations in California.

You also may have heard of these diagrams referred to as bubble diagrams. So that if you're thinking of a bubble diagram this is how we characterize California. And I don't have the rest of the WECC on here, but it's how Global has chosen to model it. So this is our existing system.

And now this is kind of where the job gets a little bit more fun, when you're building on a supply plan. Because once we've characterized the existing system correctly then we look at how we're going to grow it into the future.

And where we begin with here is basically we divide the generators into two types of resources. They're either hydro or they're thermal. And anything that's thermal is just basically not a hydro resource.

And we try to determine which ones are going to retire during our forecast period. And, again, our forecast period is 2008 to 2017 for this supply plan.

For hydro stations we only retire them if it's something that's announced. For the thermal stations it's again only if it's announced by the generator/owner, otherwise thermal stations are retired 55 years after their installation dates.

Next we try to determine how much renewable generation is required either through state legislative laws, and for those states without legislative laws we use utilities' integrated resource plans. Again, we draw on our contacts from other regional planning groups. And we also refer to the trade press to try to figure out as far as a renewable buildout what the west is going to look like as far as renewables.

And on the next page I'm basically providing where we're beginning with for our first iteration with the natural gas group, as far as what we're including as far as renewables within the WECC.

And the top number is the installed amount of renewable capacity; the bottom number in parentheses is the amount of installed wind generation that we're including in those regions.

Sometimes those resource plans or long-term procurement filings and trade press is not real clear on what's going to be added. They just say, well, some utility that operates over three states wants to include 1000 megawatts of wind.

So in order to determine a good fit for that wind we refer to something called a renewable energy atlas, which discusses the potential by state, as far as renewables in the west. We draw a lot on that. That energy atlas, if anybody's looking for it, it's a really useful document and it's at www.energyatlas, which is one word, energyatlas.org. So from that those data sources, the legislative rules, we've come up with this plan for 2008 to 2017. This is only for renewable capacity.

And once we get the renewable capacity, well, at the same time we're including renewable capacity, we're gathering the information regarding the thermal resources that we'd like to add to the system. We include named fossil additions that are deemed highly probable to come online in the next four years within California.

Outside California we use a bit different timeframe, but I'll discuss this and what higher probably means in a minute.

Again, construction lead times are the limiting factor during this time period of about 2008 to 2012. We use 2012 for California since the CEC has siting jurisdiction over many generation projects within California. This is a great source of information for us to draw on for this type of generation planning exercise.

For regions outside of California we tend to add generic fossil resources sooner as opposed to the ones with specific names. Simply because we don't have that type of siting information office for regions outside of California. And it just seemed a better approach to add what we call generic resources rather than something that is named when we don't have detailed information about its likeliness of coming online.

Not to say that we ignore named projects. We just -- they're simply in a pool and we choose not to name them because there's generally a lot more resources that are proposed than are actually feasible.

Once we include all the highly probable named fossil resources, then we try to look at control area reserve margins and check those. And determine at what point generic fossil resources are needed. And to determine the type of generic fossil resource we again use the CEC's database of planned WECC-wide generation. And another slide I'll point you to where that is.

This database is called -- it's available at the CEC's website. But for regions outside of California we include generic fossil resources, I think, beginning in the year about

2010.

And for regions outside of California right now I don't have all that data compiled to present here today, but it's looking like it's mostly a mix of natural gas and some coal electric generating stations. And, again, annually we include these generics to allow each control area to grow up to a 15 percent reserve margin, or let it grow down to a 15 percent if they're over-built right now.

For California no generic resources were included until about the year 2013. And for the most part, are generic combustion turbines since the need appears to be more of a peaking need than a baseload need in that time period.

And so this is basically just a balancing of forecasted loads against a future electric generation supply scenario.

In the past we have tried to use some of the capacity expansion models that are available either in PROSYM or in other stand-alone products. But, again, this is another model that needs to be populated with a significant amount of data. And we found that this approach tends to be more robust than trying to populate another model with data.

Again, this is basically the categories in the CEC WECC-wide generation database; and I gave you a link to where it is on the website so you could see what we've included, and what we consider highly probable.

High probability are those in categories 1 and 2, and sometimes 3 or 4, if our siting office agrees. And these classifications, as you know, can change daily, weekly. And so we've had to freeze it at 2007 just to come out with our future resource plan. Just because, again, resources tend to change categories rapidly.

Once we feel we have an adequate supply plan, we have to look at, again, the transmission between those regions. And I showed you the bubble diagram earlier, and that's the transmission that we're talking about. It's called a zonal model, whereas a nodal model tries to model each substation within the WECC. This is called a zonal model. So we just look at transmission paths between region and make sure that there's adequate capacity to move power from one region to the next, as it is in reality.

So what we do prior to 2012 is projects

that are approved either by regional transmission organizations or some other type of regulatory agency and have financing approved. Beyond 2012 we basically iterate with the model to see, there's a lot of proposed transmission projects out there.

And so we try to look at some generation statistics as far as capacity factors on stations to see whether anything may be stranded; whether some of the links between regions are fully loaded many hours, or not fully loaded. So we try to look at statistics on simulation output and decide what, if any, projects to add beyond 2012. So that's basically how we go about preparing a WECC-wide supply plan that's again used as a input to the natural gas model.

We will provide additional details of this plan, either in a section of the natural gas report, or somewhere else within the context of the IEPR. But we will provide the details kind of in a similar fashion of how I presented the details on the generation supply plan here.

So, if anybody has any questions that basically concludes my presentation.

MR. TAVARES: Thank you, Angela. Any

questions? Anybody on the phone?

Okay, Katie, will you have any follow-up comments on demand? And then after these comments we want to take a short break. But first, Katie.

(Pause.)

MS. ELDER: I didn't realize it was going to go back to the beginning of the page so my apologies for now. It takes a couple extra minutes.

Just make some quick observations about demand and Youssef was going to jump in here and interrupt and augment when and where appropriate.

You know, the input assumption that Jim talked about is an input assumption to NARG. There's a combination, part of it comes from a broader North American natural gas demand has to go into the model, and then there are the details of California and the WECC that will come from the work that Angela's doing.

And we want to think at least some about what really could happen with natural gas demand across the country. The EIA's main assumption of 2007 annual energy outlook calls for a demand of about 22 Tcf in 2005. That number grows an aggregate by about .7 percent. It becomes 26.1

Tcf by 2017. Some of you will undoubtedly remember a few years ago a lot of yak about a 30 Tcf market. And in every subsequent year I think in the six or seven years since we've talked about a 30 Tcf market. Every single year virtually the aggregate demand forecast comes down as people realize that's just not going to happen.

So, within that .7 percent growth over the ten-year forecast period there that's comprised, and this is probably a useful thing to keep your eye on, comprised a very small amount of that's residential demand. About .4 percent.

The commercial grows at 1.3; the industrial grows at 1.1. So those two are relatively in synch, but the big growth that creates that .7 percent demand growth across the country is in the long-term generation. That grows at 5.7 percent over that 10- or 12-year forecast period.

I think all those growth rates are -- to get the 2005 recorded number, so it's a 12-year total period.

The electric generation's burn been increased by 6; and that 5.7 percent. That number turns out in aggregate terms to be 6 Tcf by 2017.

So that's a lot of new gas-fired generation being built across the country.

The other thing that we noticed when we looked at EIA's discussion of their modeling effort and how they came up with those numbers is that they said that the price elasticity, so prices have a bigger effect on the generation mix than does the GDP growth of the -- elasticity. So a lot of that's not an uncommon factor -- reacts to the prices rather than economic growth.

So that goes to the prices of the relative generating sources, coal versus gas or whatnot. And so part of what EIA is telling you when they say that, part of what they're telling you is that they expect natural gas to be more favorably priced than coal, and so natural gas is increasing its electric generation burn as a result.

There may be other policy reasons behind that, not just the price. But the price is low enough in their forecast to allow more gas-fired generation to get built.

Youssef put this wonderful graph together. The thing that I like about looking at this, and it may be hard to see on the screen, especially if I'm standing in front of it, the blue line is industrial consumption and the green line are deliveries to electric power plants.

What you can see when you look at that, you can see that blue line over the period, and we've got data here back to January 2001, a consistent. I mean you've got some peaks, some annual peaks, but a consistent downward trend in industrial gas demand across the country. And a consistent increase in the gas burned by electric generators.

Now, if we go to the next page, what we put together was a graph. This goes back to January 1992, a 15-year period. You see a dramatic increase in gas-fired generation that's built. And the regions over on the left-hand side are all the different -- regions across the country. So, particularly from year 2000 we've got about 60,000 -- are these in gigawatt -- these are gigawatts, total gigawatts of capacity across the country. And you -- 60,000 megawatts. You can see that over a five-year period that number has virtually tripled.

Now the other graph that we didn't include in the package is a graph that shows what the aggregate average -- space on what the right term is -- heat rate, gas-fired capacity. And that gas-fired units have actually -- this is new capacity, been increased. The efficiency of those heat rates is actually -- those units is actually -- so that each unit is -- each unit generating is burning less gas to do it. But the dramatic increase in the amount of gas-fired capacity construction across the country is what's pushing that electric generation demand.

So those are just some things that we observed as we thought about gas demand, those are the kinds of things that Youssef and I have talked about. In general, lower demand can decrease the gas supply requirement. And all else equal that ought to result in lower prices.

And so one of the reasons that we worry about aggregate demand is that if the demand is lower the drop demand from 22 Tcf we have some lower prices. That's sort of the direction that we expect the modeling to go, all else equal.

It turns out to also be the case that lower prices are going to increase demand thought in the EIA model, and that's the price elasticity effect I mentioned earlier.

Now, I also might mention that EIA's high price case keeps demand relatively flat. So even when EIA talks about higher gas price scenario their high case still only has demand of about 22 Tcf. There are too many "t's" in that sentence. But when you look at their low-price case they let natural gas demand increase.

So what they're telling you is there is an asymmetry between the impact of high versus lower prices. High prices will keep demand relatively flat, which also suggests there's not a big price elasticity effect on the high side. In other words, higher natural gas prices don't force demand out of the market. But lower natural gas prices let a whole lot new demand come into the market. So it's an unexpected, you might say, or asymmetry there in the results.

That may have to do with the fact that we showed you that graph just a moment ago that had the industrial demand that had declined over the last several years. Part of that may be telling you a lot of the industrial demand that response has already left. And there's not a lot more of it to weed out of the market, or ration out of the market. That may be what it's telling us.

It may also imply that what I referenced earlier on the list of issues to kind of keep our eyes on and think about, you know, could we see broad-scale, large reductions in natural gas demand like we saw between 1978 and 1983. Could we see that again?

This data are the way the asymmetry in what EIA has done, sort of suggests to me that that is unlikely. Although I keep telling people they need to think about it. And the reason for that is because you saw there wasn't a lot of impact on the high side with higher prices. Didn't force a lot of demand out of the market.

We want to think carefully, though, about greenhouse gas emissions and how this issue plays out. There are a lot of people who will tell you that as we work harder controlling greenhouse gas emissions it has to increase gas-fired natural gas demand as we burn more actual gas to create electricity.

There's another school of thought that says that the real impact of greenhouse gas demand control will be to reduce electricity consumption more broadly. That, in turn, reduces the need to burn natural gas to create electricity.

The bottomline conclusion that we reached is that if you want to reduce natural gas demand you have to control electricity demand growth. Those two things are inextricably linked.

DR. HEGAZY: In other word, electric generation demand for gas, as many analysts has observed, based in the near future become the marginal application or marginal demand. The demand that set the marginal prices for the gas industry.

Just one comment about how the issue of existing generation demand for gas is complicated. The area of study, the annual outlook 2007 that came out, I think, two month ago, using the EIA gas price forecast run a model, I think, similar to PROSYM. And came out with a coal power plant, coal generation addition about 50 percent between now and 2030.

And they said majority of this addition are in CIRC and WECC. The majority are in the southeast and in the west.

We took the same, we licensed also a model similar to PROSYM with the exception that it does the capacity expansion dramatically. And we run them all again at the same gas prices of EIA, but we run it like a couple weeks ago.

We came out with almost 2 percent of coal generation addition between now and 2025, along the same; there's a five-year phase. And what came to my mind when I analyze that is either EIA has used the -- cost for new power plants two years ago because the last 18 months the -- cost for power plants, specifically for coal, on large baseload units, has increased almost double. (inaudible) and labor costs and so many different things. From what we used to hear $200 a kilowatt for conventional coal, now is $2400, $2500 per kilowatt.

So either they use the old one or there's something wrong with the models. But the point is you could run a -- take a gas price forecast; run your model; came up with a 50 percent coal additions which reduce tremendously the gas demand in the future. Or you increase the gas prices by $1, $1.50, and all of a sudden conventional coal, if there's no carbon regulation, or IGCC if there is a carbon regulation in place, will become a competitive with gas-fired, combined cycle power plant. And all of a sudden you have a tremendous shift in gas demand.

MS. ELDER: All of which is really intended to say that forecasting natural gas demand is not as easy as it sounds. I just want to make a long story short.

Do you want to press the down arrow? Oh, okay --

DR. HEGAZY: You're done.

MS. ELDER: It was done. So that's the kind of issues that we're thinking about on demand. And we're anxious to hear people add to that and tell us what they think, so that we can make sure that we have a really robust discussion about where natural gas demand could go.

You wanted to do a break now?

MR. TAVARES: Okay. Katie, thank you very much.

I think this is a good time to take a break, a ten-minute break. When we come back we're going to talk about supply of natural gas; going to talk about infrastructure; and also prices.

So, let's come back around 11:00. Thank you.

(Brief recess.)

MR. TAVARES: Okay, next on the agenda we have Mike Purcell. He's going to speak about natural gas supply. So, Mike.

MR. PURCELL: Morning, everybody. Anyway, I want to talk just on the components of the supply assessment that we're doing in relationship to the NARG model; some of the projected natural gas supplies available to California; and changes in North American production which are some of the issues that we're going to cover in the natural gas assessment report.

But just in terms of the NARG model, the big news in the NARG model is that the cost curves have been updated from the assessment that we did in 2005. Actually there's two iterations now of how the cost curves have been changed. And basically they've raised costs and decreased supply in a lot of the basins in the United States and Canada. Based on information that's out there now on showing that the resource is a little bit diminished.

Go ahead, next. And one of the major things that was done in the model was to remove, they removed 16 Tcf and put a giant field in the mid continent, and they removed a 16 Tcf giant field in the Rockies. And, again, as I've said before, they also raised costs and in some cases reduced reserve volumes.

Next slide. This is just two examples for an example of cost curves from the earlier vintage to the newer vintage. And the scale on the side is a little bit different. This one goes up to $25 and this one only goes to 20, so it's a little bit deceptive.

But if you look, the resources stayed the same, but at about 6.9 Tcf at the maximum, but on the new one it's be cost over $20 per Tcf. And in the older version it was about $15 per Tcf. And again, this is just an example. But this is kind of, you know, to show what's gone on, the major change in the whole model as far as supply curves was to increase cost and reduce supply.

This curve is interesting. This is an aggregate curve that Altos allowed us to use. And it just shows the whole supply basins in the United States. And, you know, you can see that there's about 1000 Tcf of resource. But there's still a lot of resource - I think the thing that's significant about this curve -- in the model there's still a lot of resource that's priced about $2.50 or $3, $4 per Tcf.

And, you know, that's the kind of gas that's in the ground that's being produced out of wells. And if we just stop drilling and let it come out, you know, what would be the price level. Well, not exactly. But, anyway, we'd still have to be drilling. We're still going to have to be drilling to get this cost, but there is a fairly large amount of gas that is not that high priced, you know, that is in the model right now.

Next slide, please. These are the major basins that are coming into California. Just a representation, but western Canadian, a lot of the fields in the Rocky Mountains. And, again, as we talked about before, the Rocky Mountains is much more disaggregated than this.

In, for example, the Powder River Basin, if you went to -- and all the different basins in the Rocky Mountains are broken out. The San Juan is here. The Permian Basin is here. The Anadarko is shown on here, but it's not really that important to California.

But these basins here, and then the west coast supply in California and offshore California are the major gas-producing areas in California. And in the assessment report really we're going to look hard at these basins to look at their current supply trends and what kind of gas they're really making. And we have the resources and database available now that we'll be able to take a hard look at the trends in those basins.

Next slide, please. Again, this is just another representation of those reserves. We're going to be updating this. These numbers are from two years ago, but we're in the process of updating. But, you know, for example, the western Canadian Sedimentary Basin right now, or back then when we evaluated this, was 54 Tcf of proven and 66 Tcf of potential. I think the potential reserves in the western Canadian Sedimentary Basin has risen, primarily because, you know, they're starting to find out that coal -- is working up there, and there's quite a bit of it.

Next slide, please. So, the natural gas assessment report, we're going to be looking at the resources in the United States and Canada. And how those resources have changed.

And the big news is that there is a

large resource present, you know, as you saw on that previous slide, of over 1000 Tcf of gas. But really what's starting to happen onshore in the United States now is so much of it is unconventional resource. So it has different characteristics than a conventional reservoir.

And with that you need to drill more wells to get, you know, increasingly smaller volumes of gas. So, there's reduced volume per well. And you've got to have more wells in order to get the resource out of the ground.

And that is what we're really seeing. And I've got a good chart coming up here -- next one, please, Ruben -- that shows gas production, the price of gas and the number of wells that have been drilled in the United States since 1995. And we've updated this so it's got the newer numbers from 2006.

And as you can see the blue columns are the number of wells drilled. So when you bring this back over it's about, I think, last year, 2006, about 31,000 wells were drilled. The price of gas has risen steadily since 1995 to, you know, in 2005 the average price was 7.51; in 2006 the average price was 6.39.

But through it all, with all that increased drilling, as you can see, gross production has not really correspondingly risen as might have been expected.

So, you know, what that's telling us is the same story that we've talked about for a long time here -- well, not a long time, but the last two or three years -- at the Energy Commission, that, you know, we're kind of on a treadmill and we're having to drill more and more to maintain production in the United States.

And I think that is going to be, you know, one of the themes that's going to be in our assessment. And we're going to go into more detail and drill down into more of the fine points of what's going on and really try to cover all the supply basins that are important to California in our report.

Next slide, please. So, in summary, we've got the revised cost curves that are in the NARG model and should give us some more accurate representation of the resource in the U.S. And also help with the prices in the model.

The other issue is that current drilling costs are high. The rig count is very high, but flat to slightly declining U.S. production. And so we're going to be looking at that. And we're also going to be really trying to examine the implications of those supply trends on the future natural gas supply available to California, and also in the United States.

So, does anybody have any questions? Comments? Yes.

MR. COWDEN: Thanks, Mike. Just a couple questions on the fields that were removed from, I guess the data set you guys got.

MR. PURCELL: Yeah.

MR. COWDEN: Are the data that you're using, are those the cost curves coming from Altos?

MR. PURCELL: Yes.

MR. COWDEN: Okay, --

MR. PURCELL: In turn through NPC, the National Petroleum Council.

MR. COWDEN: Okay. And then for that 32 Tcf from the two fields that were removed, could you provide a little bit more information about what fields they were, what --

MR. PURCELL: Well, they're not named or --

MR. COWDEN: Okay.

MR. PURCELL: -- in that sense. I mean they were just a statistical representation that was in the database before, you know, in the aggregate supply. And so what happened was they were just pulled out, you know, out of kind of the total pie. And so they're not going to be found.

But the way the statistics work, and we could talk about that more, maybe, you know, offline, but the way the USGS kind of handles that, you know, -- discovery or the discovery process model, maybe is the name of it.

But anyway, it has certain amount of fields that are found in a probability, you know, spread across the probability. And so they're not, you know, they weren't on paper; they aren't actually found yet. They were just kind of in the mix that possibly could have been found. And that's what -- they've removed them out of the model now. So, you know, there's not going to be that kind of resource found.

MR. COWDEN: Okay.

MR. BRATHWAITE: If I could say something, Bob, your question.

MR. COWDEN: Yeah.

MR. BRATHWAITE: In the model there is a category known as yet-to-find. And what Mike's talking about --

MR. PURCELL: Exactly, yes.

MR. BRATHWAITE: -- some of those yet-to-find resources were removed because of the cost considerations and those other things on day-to-day, the cost could not be presently used in this cycle.

MR. PURCELL: Okay, yeah. Because that was -- thank you, Leon. Because that's the way to say it, is the yet-to-find resource. So, thanks for the question.

Anyone else?

MR. TAVARES: Any more questions?

MR. PURCELL: Thank you.

MR. TAVARES: Anybody on the line? No?

Okay, next we have Bob Logan. He's going to explain actually the current status of the work that's being done for the Energy Commission by Mr. James Jensen; he's doing some kind of work on the liquified natural gas world trade. So, Bob.

(Pause.)

MR. LOGAN: Okay, hi. I'm Bob Logan and

I'm here in place of James Jensen because he's in Boston where he works out of. But James will be here on June 7th when the next natural gas hearing/workshop will be held.

You all have access to the slides he prepared. And what I've done is skip to the very last slide, which is, in my opinion, the most interesting slide that he prepared.

This is his projection of world LNG supply by region. For those of you who aren't familiar with James, James Jensen is an expert in LNG worldwide supply. He has appeared at the Energy Commission before. And there are three of his reports on the Energy Commission website. For those of you who are interested, there are directions on how to find those on the website.

And as you can see, what he's showing is the base year of 2005, somewhat less than 20 Bcf a day of LNG supply, broken out by the various regions with the legend over here on the right.

What I'd like to do is direct your attention to 2020 where, as you can see, he's projecting that over that 15-year period the supply that's currently a little under 20 is going to increase to somewhere in the 47 Bcf a day area.

However, not all of that would necessarily be available directly to California. In fact, if we go down the legend we see that the top category is Caribbean. While the Caribbean is clearly available to the United States, it's very unlikely that any Caribbean LNG would find its way to the west coast.

Similarly for the next category which is northern Europe. Again, not come to the west coast. And the next category, west Africa, is unlikely, as is the next, north Africa.

But starting from the bottom we can see that Australia, from a rather small amount in 2005, is going to significantly -- is projected to significantly increase, and would be in the Pacific Basin and likely available for the west coast.

The next category however, southeast Asia. As you can see this is the one category that decreases over time. This is primarily Indonesia. And what Mr. Jensen is basically projecting here is that Indonesia LNG available to the market will decrease. Which is likely due to the fact that Indonesia is going to use more of their natural gas in-country and export less of it.

I'm not sure I can pronounce this correctly, but Sakhalin is the Russian LNG; as you can see there, a small amount. This would be in the Pacific Basin.

The next very small line is Pacific South America. So this, as you can see, is not projected by Mr. Jensen to be a very significant source.

And now we come to the very largest source of projected increase in LNG supplies, and that's the Middle East. And this is largely Qatar; and the increases that Mr. Jensen is seeing in the Qatar LNG production and exports.

And this is the swing resource. It's located right on the seam of the globe. And while it can come to the west coast, it's just as likely to stop off by India or China or Korea or Japan before it would make it all the way to the west coast. And it can also go the other way to Europe. So it's just very hard to tell at this point where that LNG will go.

But what this basically does is it gives the Energy Commission and those of you who will be getting his full report when it's available, which will be before the June 7th workshop hearing here on the assessment report, it gives a feel for what projected worldwide LNG supplies are likely to be. And what the availability by region is likely to be.

I should say that Mr. Jensen is currently writing his report. And if anybody has questions or suggestions you can feel free to email those to Ruben. His email address is on the handouts. And we will pass them on to Mr. Jensen and ask him to try to include -- to address any of your questions or comments.

I can take any questions or comments today, but I can only pass them on, as Mr. Jensen's our expert in this field.

Yes?

MS. SCOTCHER: The Commission's trying to get a projection of what's going to be available to the west coast, this is a good first supply. But it's also very important to consider the world demand picture, because who knows where that's going to flow. It's going to depend on the demands everywhere in between, all around the world. So, that's just something to keep in mind.

MR. LOGAN: Yes, and he will be

including that in his report. But this is sort of a sneak preview, so to speak, of part of his report. Let the public know the report's coming and who's preparing it and the topic he's going to be covering.

That's it, thank you.

MR. TAVARES: Are there any questions on the line? Anybody?

Okay, Katie or Dr. Youssef, anybody?

(Pause.)

DR. HEGAZY: A couple of trends on the supply side that we noticed and the industry analyst has noticed that would impact any modeling of natural gas price forecast. And Mike has alluded to them.

One is the fact that production has been declining in the local United States market for the last few years. The other one is obvious increase on the cost of producing, especially the cost of finding and development.

They have an analysis done by the, just as an example, but there's so many of these examples around, by the Association of Independent Petroleum Producers, just to give you the exact name, Independent Petroleum Association of

America, in which they show that -- quote an internal study for them, that the cost of finding and development has increased between 2000 to 2004 by twofold, from $6 or close to $6 barrel of equivalent oil to $12, $12.7 per barrel of equivalent oil.

That's a tremendous increase in the cost of production. And the main reason they quoted, and other people has quoted, is the increasing discovery cost and labor cost basically.

The other important issue in that is the risk associated with that activity, in gas and oil, as well. The risk is coming from the fact that the production rates, or discovery rates of oil and gas is not as it used to be. And the uncertainty about demand and the global market.

And Katie mentioned earlier that 275, the total consumption as stated was 22 Tcf; at the same time the production level was at 19 Tcf. That's actually been the trend in the United States since 1988, that there's a gap between supply and demand. This gap, in our view and many other analysts, is the main driver behind the volatility and the increase, the continuous increase in gas prices in the marketplace.

We're going to come back to that later, but this graph, a similar graph has been shown in the earlier presentation, but it just show that the number of gas rigs from January 2002 has been increasing steadily, while the production has been, at the same time, decreasing or declining steadily.

The increase in unconventional production insufficient to offset conventional decline. That has been shown by the one is the actual statistics, and also is something that been picked by the NBC 2003 study projection.

Major supply issues and impacts that we might have to dig into in order to come up with a set of alternative assumptions -- was the basecase assumption that Leon and the group is using. One is, again, as I said, the production is declining. The gaps between production and consumption is also increasing between consumption and production increasing.

For example, between 1995 till today that gap has been shifting between two and three or ranging between 2 and 3 Tcf. Meaning that the United States, lower 48, require between 2 and 3 Tcf a year to rely on the outside market.

Katie mentioned that the big companies, Shell and British Petroleum and others has been coming back home. And was there a specific reason for that -- you want to say something on that?

MS. ELDER: I need to talk into the microphone. I think Shell's proposal or announcement was that they would spend about $1 billion in the Pinedale in Wyoming to develop new gas supply there.

And bp, if I recall correctly, was going to spend about $1 billion in the San Juan, which is interesting, if for no other reason then, we have a whole lot of folks who have said San Juan's done; there's no gas supply; should begin to decline there; the coal, methane, we were able to get out of that basin is now begun to decline. And that there's no way on earth that supply in the San Juan will ever increase again.

Of course, I happen to remember that being said about ten years ago as conventional supply in the San Juan disappeared.

So, the thing to keep your eye on is what the majors are doing, and what new technology they'll apply, and when and where. And just as I mentioned earlier, watch where they're spending their investment dollars.

DR. HEGAZY: The two major -- everyone knows is several supply venues -- the two most important one of them, according to many analyst, to rely on or to look at in the long term is -- the first one, of course, is liquified natural gas. I saw an estimate that if you add the current LNG activities in the United States, the one under development and the potential, it all add up to around 6 to 7 Tcf if all materialized.

I don't know how that number would fit with the study that the consultant for the Commission is doing.

The second major one is the Alaskan pipeline in the future, but that doesn't seem to be coming before 10 to 15 years. That would add another 2 Tcf to the supply portfolio.

The other onshore and offshore and the federal areas, each one of them amount to half, 2.7 Tcf. So they're not a major potential supply that would impact the supply portfolio as much as the liquified natural gas or the Alaskan pipelines.

Again, the marginal cost of production appears to have increased. And I said there's a study that has shown a least part of that marginal cost production, refining and development is increased by twofold.

And of course, the Rockies and the deep-water, there's a lot of reliance on in the Rockies to deliver as much supply reserve to the -- do you want to add anything? Any question about -- or comments?

MR. TAVARES: Any questions or comments? Yes.

DR. PHINNEY: Suzanne Phinney with Aspen Environmental Group. There was, on your last bullet there, that LNG makes up the difference, and I know EIA is projecting that. And the comment was made about demand elsewhere.

How are you factoring in that there may be enough LNG supply, but the price to get it to the United States may be well over, you know, current, or at the prices at that time, because so many cargoes may be diverted to other countries that would be willing to pay more? Or is that a factor?

MR. FORE: That is a factor and that's why we're using the World Gas Trade model to account for Europe or Asia bidding away that gas that could come to the U.S. And we've seen that in just the last couple of years, and that everyone thought LNG was going to take off a lot stronger than it has. And the price in Europe caused a lot of cargoes that might have come here on a spot basis to go into Europe.

And so the key will be if we have the right cost structure in the international market in terms of the demand for gas in Europe and Asia.

But we're trying to account for it is all I can tell you. And we'll just have to see from the results if we accounted for it properly or if we need to make some adjustments later on in the model.

MS. ELDER: And that's a place where we can feed that back into the qualitative discussion after we develop the reference case, is we can talk about that issue, you know, what did the model come out with; what do we think about that; does that make sense; what happens if the opposite occurs, et cetera. That's exactly the kind of discussion that we want to build in.

MR. TAVARES: Any more questions or comments? Anybody online? No.

Okay, next we have Leon from the staff;

he's going to make a presentation on the infrastructure.

(Pause.)

MR. BRATHWAITE: Okay, I promise I'll be brief, you know, since you guys probably tired of seeing my face, anyway.

Anyway, what I want to talk about here is the infrastructure within the model; and how they model it, some of these issues and what sort of results we might get out of it and all that good stuff.

Anyway, the World Gas Trade model uses three type infrastructure representations. One is the transportation corridor. And the transportation corridors can be one of two things. It could be a pipeline which links a supply basin to a demand center; or it could be a ship linking a LNG liquefaction facility to an energy regasification terminal.

And two, we can have an LNG liquefaction facility and we can have an LNG regasification terminal. These are all infrastructure types that are contained within the World Gas Trade model, which, of course, includes our normal NARG model.

All pipeline systems in North America

are represented, and all major pipelines extending to the west are also represented, like El Paso North and South, like TransWestern, GTN, Kern River, Southern Trails, North Baja, all of these things are represented in the model -- are represented inside the model.

These are the major pipelines in the west, and their associated capacities. Gas, GTN about 2090, all the way down to TGN at 174. And these are the pipelines that deliver natural gas to California.

Then there are some pipelines which come to California but do not deliver gas in California or deliver very little, like Tuscarora and North Baja. These things are also represented within our World Gas Trade model.

So, in addition to the pipeline capacities, which I just showed you a little while ago, there's some other factors or parameters that we must put into the model. One of them being the tariff. And that is the cost of moving gas from one location to the next.

Now, that tariff may include both a demand charge and a volumetric charge. Also we need a pipeline efficiency or fuel use, and that is normally expressed as a percentage. That is the amount of gas that is used to operate the pipeline system. This number normally varies between 1 percent and 4 percent; it depends on the pipeline system that's under consideration.

Also, the other parameter or parameters that we must put in has to do within the investment criteria. And these investment criterias are used to determine if and when a pipeline expands.

And this is a schematic that shows the supply basins. I think Mike showed this schematic previously. But it just shows all of the pipelines in the west, and you see all the major corridors that we have. Like, for instance, this is GTN that comes down all the way to Malin before it enters the PG&E system.

Then we have, from the Rocky Mountains we have Kern River coming across here and delivering gas into the southern part of the state, and moving gas all around.

So, this is the major pipeline systems. It is all represented within the model. We try to get as good a representation as we can, both in terms of the structural disaggregation and the costs and necessary criterias that are associated with the system.

Okay. LNG liquefaction in North America. There's only one LNG liquefaction facility in North America, located in Alaska, Cook Inlet. But all of that LNG, it's a small amount, goes to Japan. So it makes very little. It's represented but it doesn't make very much difference within the model.

LNG regasification in North America. Have five terminals that operates in North America as we speak. We have Everett in Massachusetts; that's about 1 bcf, a little bit over. We have Cove Point in Maryland; about 1 bcf per day. We have Elba Island in Georgia with a capacity of about 1.2 bcf a day. And we have Lake Charles, Louisiana with a capacity of about 2.1 bcf per day. And in the Gulf of Mexico we have Gateway Energy Bridge with a capacity of about .5 bcf per day.

Then there are facilities expected to produce first gas in 2008 or 2009. These are also included in the model. Costa Azul in Baja, Mexico, with a capacity about 1 bcf a day. And terminals in the Gulf of Mexico with a combined capacity of about 3.3 bcf per day.

Okay, now the model also allows for expansions, but the expansions can occur in one of two ways. First way is that we can hard-wire the schedule. We can tell the model that this is the expansion that must occur at certain times.

And these are based on like public announcements. If, for instance, we know first gas is going to come at 2008 and then we going to have first expansion at 2010, we can tell the model this is how we're going to operate from here on out.

The other way we can do it is also is that we can just allow the model to expand on its own, what's called economic expansion. But we'll give it a date certain. And after that it can expand economically as it so see fit.

Now, each terminal within the model, each LNG terminal within the model has an associated cost for regasified LNG. So, for instance, at Costa Azul, now I'm talking about Costa Azul because it's identified LNG facilities under construction; we all know about it, okay. So, it's not generic, it's identified within the model.

So the regasification cost at Costa Azul for instance is 15 cents per Mcf plus a charge based on its throughput or based on its utilization. So normally we would see at about a 70 percent utilization rate, you may see a cost of about 50 cents to regasify the LNG.

Now, terminal in southern California. A bit controversial, and there's a lot of uncertainty surrounding any terminal coming into -- in California. We did have Long Beach; we know it's no longer. That doesn't look like it's going anywhere. And we don't know about any other ones. There are a lot of uncertainty surrounding up to now in southern California.

So what we are doing here is that we are not allowing any regasification of LNG to occur in any terminal in southern California, at least on this cycle, until we have some better information about what LNG in southern California.

So we just going to -- even though the model has the structure for it, we're going to turn off that facility and make sure that it doesn't flow during the forecast period.

Okay, sources of information. Where we do get our information from. FERC filing; EIA, Energy Information System; Natural Gas Intelligence; Lippman Consulting, Incorporated; Statistics Canada; and any public announcements of private industry, which we use quite a lot, you know. We may investigate them a little more before we actually put anything into the model, but we do use that as a source of information.

With that I'll take any questions and any comments as long as you need me here; I'll stand, you know, I have to pay my penance, I guess, but -- that's a joke, please.

Questions and comments, yes, seriously. Yes.

MR. PAK: I was just looking at your list of pipeline capacities. Are you going to be updating that for 2008?

MR. BRATHWAITE: Updating it for 2008?

MR. PAK: Yeah, TGN, for example, is under represented. I think North Baja is, as well.

MR. BRATHWAITE: Okay, we'll certainly look at it, yes.

Any other questions, comments? Yes, Bob.

MR. COWDEN: This is a disincentive to

ask questions.

I'm curious what terminals you're going to expand kind of on a hard-wired basis. And over the outlook are you going to expand Costa Azul?

MR. BRATHWAITE: Yes, Costa Azul will expand, yes.

MR. COWDEN: I'm curious when?

MR. BRATHWAITE: After 2010.

MR. COWDEN: Anytime after? Or, I mean --

MR. BRATHWAITE: Well, I mean the first expansion I think will occur in 2012, actually. But, I think after 2010 it will be allowed to expand. I mean Costa Azul have already made announcements about expanding their facilities 2.5 bcf per day. And that may occur somewhere around 2011, 2012.

MR. COWDEN: Right. Are you going -- I mean they've also talked about maybe delaying that expansion.

MR. BRATHWAITE: Yes.

MR. COWDEN: Are you going to look at different scenarios around I guess LNG terminal buildout on the west coast?

MR. FORE: Let me take a stab at it.

Costa Azul, after a certain time period, 2012, the model will expand it if the gas is demanded. We don't hard-wire your expansion in necessarily. We just say it's available to be expanded, and if the model indicates that gas is needed there, it'll expand the model.

That's the same way in the Gulf Coast. We have some plans we've hard-wired in because they're under construction. But then after a certain time period, 2010, 2012, we only -- they can expand but we don't hard-wire it. The model will say the investment criteria is met and so it'll expand those facilities just as a generic facility there.

And so on the Costa Azul we know they have expansion plans, but the model will tell us whether you're going to increase the volume there based on the demand. We won't require it to deliver that volume into it.

So, after a certain time period we really don't hard-wire anything. We let the model decide whether it's going to come. Now, we may say where it will be located, you know. We haven't put any on the west coast. In a sensitivity we might put one in Oregon, up in

Canada, one that's been permitted, and say, okay, it'll be available. But then we'll let the model decide whether the gas is going to flow there or not.

MR. COWDEN: So, I know, sometimes the model likes to expand in, you know, dribs and drabs a little bit.

MR. BRATHWAITE: Yes.

MR. COWDEN: And are you going to, you know, -- as regas terminal is not necessarily going to expand in dribs and drabs. Are you going to try to correct or somehow manage the dribs and drabs that the model wants to build out?

MR. BRATHWAITE: Well, I mean, now you're talking about art rather than science in terms of modeling, okay. However, yes, we do try to, when we go back and review some of the models output we do try to correct some of those dribs and drabs, as you call them. But it is an art rather than a science in getting that exactly right.

But once the model tells us that a facility wants to expand, and we get a result that says that it does, it's just a very good indicator of what could potentially happen in the future.

It doesn't necessarily mean it's going to occur at that volume, at that level, but we try to get it as best as we can.

But, yes, we do try to correct the dribs and drabs, as you mentioned, yes.

MR. COWDEN: I thought you mentioned this, but in the IEPR, or in the national gas assessment, are you going to create scenarios that then look at geographic effects of different terminals or, you know, that try to look at under status quo maybe there's a very low throughput through a terminal. And maybe if there's some policy things that you could adopt there'd be a higher throughput through the terminal? Things like that.

MR. BRATHWAITE: Well, -- I'm sorry, Katie, do you want to go ahead?

MS. ELDER: No, go ahead, Leon; I'll follow up.

MR. BRATHWAITE: Oh, okay. Well, we have five scenarios that we are going to be running, okay. The first thing obviously is a basecase scenario. And then we're going to be looking at four oil price sensitivities; you can call them sensitivities rather than scenarios.

Now, beyond that we may eventually get into some of the more like LNG scenarios and that kind of stuff, but that is not in the plan as we speak right now. But we will -- but I suppose at some point in time we will have to get into some of the more looking at what happens, you know, for various LNG facilities at various locations.

For instance, maybe southern California may come in say let's say in 2010 for instance. We could look at those things and stuff.

Maybe Katie will want to add something to this?

MS. ELDER: Yeah, Youssef touched on this earlier when he mentioned that if we could actually let all the things vary that we'd like to vary, and we could run scenarios for each of those, we'd never stop running scenarios. I mean, you know, I think the phrase he used was it would take a lifetime.

What we're going to do in this particular process this year in the 2007 IEPR, the plan is to use this reference case with the explicit sensitivity scenarios that we've talked about around oil prices, and then everything else is going to be generally qualitative. We're not going to be able to sit and run NARG ad nauseam the way we might like to, to say, okay, let's change this assumption and see what happens. Because there's just not enough time to do it. Not enough time and resources to do it.

So that's why we're trying to get to this process of creating this more facilitative, let's think outside NARG and think qualitatively about well, directionally, if you change this, what would be the impact, and what does that tell us about the world.

MR. COWDEN: Okay, thanks.

MR. BRATHWAITE: Does that answer your questions, Bob?

MR. COWDEN: Yeah, thanks, Leon.

MR. BRATHWAITE: Sure, okay. Any other questions, please? If not, thank you very much.

MR. TAVARES: Thank you, Leon. Any questions online? Anybody?

Okay, now we have -- we're going to be talking about a most interesting part here of the natural gas assessment. It wasn't supply, it is the prices. Sorry, Mike.

And we have with us Bill Wood.

(Pause.)

MR. WOOD: I guess it's afternoon, so, good afternoon, ladies and gentlemen. As Lee indicated, I'm Bill Wood. I've been with the Commission for a number of years. And I've been asked to speak a little bit about our natural gas prices.

There aren't really assumptions associated with the gas prices. Those kind of fall out of the work that we've talked about up to this point.

And the basis for those assumptions -- the prices, are basically these assumptions that were on our announcement. And those are basically now what we're proposing to use to drive the models to come up with what our price forecast should be.

Now, there are, within the Commission our natural gas prices are used for two principal purposes within the Commission. One is to feed the electricity generation evaluations. Generally that's probably our biggest effort in that area because we generally run multiple scenarios in conjunction with the electricity office.

We also do a utility retail price forecast which is then provided to our demand office, which also then does a forecast for residential, commercial and industrial demand. They're principally using the natural gas demand as a alternative to electricity demand. So it's more of a fallout from the electricity -- from the demand office as regards to what the natural gas demand is.

So, I'll be discussing today then how we make use of the natural gas prices coming out of the model for electricity generation; how we take into account short-term assumptions for that; and then briefly the utility forecasting that we do. And then finally some impacts that might have moved the natural gas prices up or down.

Here we see a graphic that speaks to natural gas prices at various postings throughout the U.S., principally on the west coast, but I've included a Chicago price as well as the Henry Hub price.

We see lots of -- we see basically a lot of differences in the regional prices, but basically they tend to follow the same sort of trend throughout the U.S. Our assumption is that this kind of differential can be expected to continue into the future.

Now, one of the things that I want to do in association with our work here is to look at the trends that we see here. And then the differences of those in the market, or in the industry is called the basis differentials. I want to look at those bases and see whether there are any shifts, significant shifts that occur in our forecasting into the future. And if there are, then to comment on those and try to explain why those shifts might be occurring.

Now, one of the things that we have found in our work over the long period is that it's not the forecasted price that is most important in our modeling efforts, but it's the relationship between the prices in different areas.

We've received -- well, I've been doing forecasting for a number of years, as I've indicated, and in some years we get comments that our prices are too high; other years we get comments that our prices are too low. But nevertheless, it seems that the information that we provide to the marketplace with regards to where it's going with return supply, supply and price and -- or I should say supply and infrastructure, tends to be -- show up in the marketplace later in the timeframe.

For instance, 80 or the late 1980s we thought that El Paso might reverse its pipeline. And two years later it did. We figured that the Kern River would be a very hot spot for California with regards to gas coming into California, and it was. We thought the Mojave pipeline would never really fill up during the forecasted period that we were looking at, and it's running at 50 percent. Now I think it's running at about 25 percent capacity.

The reason that the model works so well then is not because it's forecasting absolute prices correctly. What it's forecasting is, is the differentials between the different areas, the different supply regions, and the different demand regions.

Basically in the model we have supply areas that are competing for demand. And we have demand areas that are competing for supply. And so the market then, the model basically then tries to satisfy all of those supplies and all those demand considerations and comes up with a specific price.

So that price then is based upon the differences that are within the different regions that the model is looking at. That then drives the production requirements and also drives the infrastructure requirements that we have in the model.

Likewise, the electricity model also has power plants scattered throughout the western states, and I'm talking about our electricity model, scattered throughout the western states. Now, we used to try to provide a specific point forecast for different areas in the state within the various states. And that didn't really work because it ended up that just like in the gas side, supply and demand competed for product.

In the electricity model we found that the different electrical generation power plants competed to meet demand throughout the western states.

So, a single price for all of them wasn't representative. A price for a particular single price for each region wasn't indicative of what was going on. What we needed was prices that were more specific required for each one of the power plants that fell within the electric generation area that was included in our models for the western states.

And the important thing that we found was that it was the differences in price between the different regions that was important. Southwest supplies versus Pacific Northwest supplies. Those were the important things that basically drove the model as to terms where prices were going to go.

So, basically what we have done, then, is we have looked at all of the power plants. We've worked with Angela and others within the electricity office, and have looked to see where every power plant is located. Whether it's existing or whether it's proposed.

We looked to see where those are located, and then we have then identified what source of gas there would be for each one of those particular power plants. Those power plants that had similar locations and similar sources of gas were lumped into what we call the natural gas fuel group, or a fuel group or something along those lines.

Here is a representation then of all the fuel groups that we have within the model that we provide information to Angela. And Angela then provides us back information with regards to the demand associated with those.

There's in excess of 30 different pricing locations in the western states that we are looking at. For instance, if we look up here in the Pacific Northwest you can see there's a number of them there. We have one that's just south of Sumas that represents, we call it the north coastal, or the coastal pipe -- or area. That represents the pipeline. Those generators that are receiving gas off of northwest pipeline coming out of Canada.

We have another one at -- my glasses aren't working that well, but right there, I believe, is Malin. There are a number of power plants that are located in the area of Malin that are pulling gas off of GTN.

We have another one here in central Pacific Northwest. We have indicated these represent power plants that are receiving gas off of utility generators -- or utility pipelines.

Likewise in southern California, well, let's go to PG&E. In PG&E we have three different fuel groups. We have those old plants that are receiving gas off of PG&E and are paying distribution costs. We have new power plants on PG&E system that are only paying the backbone rate.

We also have SMUD separated because they have a different transportation rate also on the pipeline.

Generally speaking the services that these fuel groups represent then are services from interstate pipelines, from utilities, are direct from production. Now, in some cases it's one, or maybe it's all of these particular, all of these.

For instance, in southern California we have one that's called the EOR fuel group, enhanced oil recovery. It is receiving gas from Kern River, from Mojave, from SoCalGas and from California production. All of those are feeding into that. And what is included in that fuel group is not only the generation plants, but also direct steaming that may occur.

We also have in that same general area one plant that has been identified that receives gas directly from a gas field, and that's Sempra's facility at Elk Hills. It only receives gas off of that particular facility.

Same way with down here. We've separated out pipelines that are power plants that receive gas on the northern El Paso system, Transwestern system, and those who receive gas off the southern system. At one time we had one price for the Nevada folk. But now we've indicated that in Reno we had gas coming in from the Rockies on Paiute, and we have gas coming in from Canada on the Tuscarora pipeline.

So that's one kind of gas in comparison to what's coming off of in the Las Vegas area where we have gas coming off of Kern River and also gas coming off of southwest gas directly delivering to utilities. So, we've taken these kinds of things into account in the model.

Here's the next two slides are representative of the different kinds of fuel groups we have. And I'm not going to go through these any further than we have now, but the next two slides have for Nevada, southwest, Rockies, North Baja. I didn't mention them, but we do have North Baja. And, by the way, North Baja in the model is allowed to reverse and expand. I think that's hardwired into it, after LNG comes into place.

Now, there is inter-reaction between the fuel -- the natural gas group and the electricity group. We provide natural gas prices to the electricity office by the fuel group. Then the electricity office then has programmed each power plant within that they have in their resource base to receive gas from one of those particular gas groups at the indicated price.

So then whatever Angela does at that point, then, she turns on her model; makes all the modifications, other kinds of things that she has to do to make sure the model is running correctly and is coming out with reasonable responses.

And then when she's happy with her results, then she provides us back then electricity demand for each one of those fuel groups. We then put that electricity demand into our model and then along with other changes that we may have to do, then we re-run the model.

Now, when we're doing sensitivities or when we're doing scenario work, sometimes there are more than one iteration in doing those. Sometimes there are four or five iterations to get something the way we want it.

Now, the model produces what we call an

annual -- it produces an annual forecast. But the electricity office needs a monthly forecast. So several years ago I looked to see what the -- how the monthly swings were.

Here, these are an average of -- well, basically these are multipliers that I would apply to an annual price in order to come up with a monthly price. And I've looked at some of the -- these are based upon about three or four years' worth of data that occurred after the energy crisis.

And as you can see, they pretty much follow the same trajectory. There's some months when some of them are higher and there's some when some of the other ones are lower and so forth. But we tried using these directly in the model, in the electricity model, and we had difficulties. Or at least had difficulties with the model that it was too much change going on between the different areas.

So, basically what we finally did was we presumed that the specific differentials that the model provided us on an annual basis were sufficient enough to show the differences in the pricing schemes throughout the different regions.

And what we basically did then was just develop one seasonal curve that was applied to all the fuel groups so that the electricity model would be more responsive. And it does not vary that much, as you can see. Things are really very close to each other here.

Now, one other thing that we do that we have been questioned in the past, was our short-term price forecast never really looked for a close to what the real -- or what the actual prices were at the time. We've always had this problem from the time that I can remember, but it's more pronounced now since prices are much more volatile.

So during the last couple of go-rounds we have developed a methodology that allows us to try to convert short-term prices into the model. Basically we're using the Nymex Henry Hub differentials. And to do this we're averaging 30 continuous daily strips for a three-year period on a monthly basis. And then we're averaging 30 continuous daily spot prices that are representative basically for those. And then -- that best represent the fuel groups that we're looking at.

And then we have determined the differences between the average of the historical fuel strips for one month versus what our spot prices, our posted prices were for those different regions and came up with a differential. That differential then may be positive or negative, depending upon the location.

What we did then was there was a differential then that was specific for each of the fuel groups. What we did then was we applied that differential to the average -- what do we call it, strip? The average strip for those 30 days. And if it was positive we added it to it; if it was negative then we subtracted to it. And we did that for the 36 months.

Now, when the strip crossed the long-term forecast then we dropped the strip and we shifted over to the long-term forecast. So that's how we transitioned from the short term to the long term.

Now, I wasn't directly involved with this so I don't have an example to show you, but basically it's if we were looking at supply coming out of the southwest, normally if we're looking at something in the Topack area, our prices are generally lower than the Henry Hub, so we would actually be subtracting some sort of differential from the Henry Hub price, to obtain a price that would be representative to those sources that are in the southwest.

Okay, we also did the utility retail price forecast. These fall out of the model. Used to be that we had to do a month or two of offline analysis in order to come up with these, because we basically were taking the commodity price at the California border, and then placing those into spreadsheets to come up with prices for the residential, commercial and industrial sectors. But now we've developed a model so that it can do this for us.

We basically -- you've already been explained to you the residential, commercial and industrial areas that we're forecasting. But we also take then those residential, commercial, industrial prices and provide them to the demand office. They only work with annual numbers, so they were not concerned with providing them monthly numbers.

But basically they get a residential price from forecasts for us for each of the

California service, or California utilities. And also a commercial price. And then for the industrial sectors we're converted to the nexus, everything is converted to nexus to represent the industrial sectors. And those conversions from industrial to the nexus is based upon information that the utilities provide to us through their filings.

I indicate that we only provide a preliminary and final reference case forecast. Generally speaking there are two forecasts that they receive from us. One of them is the beginning of their demand cycle analysis. And then we provide them another one at the conclusion of their analysis. They, generally speaking, do not run scenarios or sensitivities associated with any of their analysis or evaluations.

Okay. Assumptions with regards to these retail prices. As we said, they represent, generally the retail price represents a commodity and the utility distribution costs. For the commodity component we just use the weighted average cost of gas for PG&E and SoCalGas. In the old days I used to do a hand analysis that would weight -- it and come up with different, I'd have spot price and contract price and whatever that came up, and through some manipulating of the data that came out of the NARG. But it was just too burdensome and we just don't -- it doesn't really add that much to the results.

For San Diego we're using as the commodity SoCal weighted average cost of gas, plus any transport costs that are associated with moving the gas through the SoCal system.

The rates that we use for distributing the gas within the utilities was based upon 2005 CPUC decisions and effective tariffs that were then being applied. Those took in then the most recent PG&E gas accord, gas accord 3; and also the SoCal and San Diego most recent, what do you call it, base -- I forgot. My mind's gone blank. But anyway, when looking for the costs to distribute non-utility costs.

More recently, SoCal and San Diego just received a decision associated with allowing them to go forward with firm access rights. We're not certain exactly whether those are going to have impacts on our analysis, though it would be easiest for us to put it in because we do have the transportation corridors already in place in the model. I don't see that it's going to have a significant difference in our evaluations of things that happen there, but it will be interesting once things have settled down in that area, to see exactly how it will impact our forecasting for southern California.

Now, with regards to natural gas prices, those things that have the big, big impacts on natural gas prices. Basically it's two things. Our assumptions associated with natural gas resources, and also the assumptions with regards to what the electricity demand is going to be. Those are the two big drivers associated with price in the model.

How much resource we have in the model, and how much it costs to pull the gas, or to produce that gas is important. It leads into different areas competing differently. If we were to change the Rocky Mountains and make it more difficult or more expensive to pull gas out of the Rockies, that would then have an impact on gas all over the U.S., but it would also impact us.

The more supply that we put in the Rockies, for instance if we say -- I'm sorry, the more supply we put into our resource base the cheaper generally the end-use price will be. Because of competition, the more supply you have available the competition will then drive prices down. Down to, you know, to a level which can't go any further than the replacement costs associated with the gas. But it has an impact of reducing prices.

Electricity demand. We had indicated earlier, I think it was Katie that indicated that the driving demand -- or the force that is driving the increase in demand in the United States -- California and the United States, is electricity. The need for electricity and the meeting of that demand using natural gas.

So, in California during the last cycle we actually put in a lot of renewable resources into our analysis. That had a substantial impact on the gas demand for California and for the western states. We used to have gas demands for electricity -- overall gas demands increasing at 2 to 3 percent a year. And now I can't remember, but it's 1 percent or less. What is it, Jim? I'm sorry, Jim was waving at me, I think.

Oh, okay. I remember that the results of putting the renewable resources in was dramatic in terms of what it had an impact on gas, gas requirements.

On the other side then, if we can do things that are associated with reducing electricity demand, and that's going to be the hard one because we keep getting all these new gadgets. You know, I get up in the middle of the night to do a little stretching, if you would, and I see all of these in my bedroom where we have our computer system set up, and I see all of these little lights on. I look at my monitor has three lights on it; my computer has a light on it; my modem has three lights on it, you know; and my printer has a light on it. The fax phone right next to it's got a light on it.

So, all of those are drawing energy. And if we haven't shut off those pieces, then they continue to draw energy. And it used to be that -- I have seven daughters, and they all have hair blowers. Well, you know, the old hair blowers were say, I don't know, 50 watts. And now then they grew to 100 watts. And now, I don't know, what are they, they're, you know, the wattage on these things continued to go up. And they still use them at the same amount of time. Fortunately

I don't have to pay for them anymore; they're all married and moved out. But in any event, it's hard then -- it's going to be hard to reduce the electricity demand.

On the gas side we've done it. Twenty-five years ago when I first came to the Commission the average use of gas in the state was 125,000 cubic feet per year. It's down now to 55. That is a tremendous reduction, and it's going to be hard really to reduce that any further than that.

So, if we want to reduce demand in California and elsewhere, we have to look at the demand for electricity.

And, of course, all of these have impacts on gas prices. They have impacts on the need for electricity resources. Has an impact then for also impacts on the infrastructure for natural gas.

I've kind of got off track here a little bit, but in any event that's what happens when you know too much for your own good.

Anyway, is there any questions or comments with regards to what I presented here today?

Yes, Youssef.

DR. HEGAZY: Just one question about the gas phases and the power plants gas consumption. Most of the power plants, specifically the newer ones that came after 1999 or 2000, in the long-term contracts for gas supply are in some sort of arrangement for three to five years at least. Is that considered or you assume all of them are supplied by the spot market or --

MR. WOOD: Well, basically our forecast -- Youssef basically asked me whether we take into account contractual requirements for the power plants. And the basic answer is no. We do not take into account individual contracts.

We presume, since we're doing an annual forecast, that the model is averaging spot prices with contract prices. So what we're getting, what the model is providing to us then is a weighted average price of all sources of gas that are available to it.

And we're presuming in our forecasting then that the owner of that particular power plant will be prudent in his purchasing of supplies, and will be making use of those delivery facilities which are nearest to him.

And that the price that will be provided to him will then be basically whatever the market's providing.

By the way, I forgot one thing with regards to the end-use prices. We basically are holding -- we will determine then what the mark-ups are, or what the utility tariffs are for each of the sectors by utility. And then we hold those constant in real terms.

It used to be that we went through the process of calculating about what the margin was going to be based upon a formula that took into account inflation and demand increase and efficiency factors. And then we looked at it to see distribution rates before all of the, how you distributed those margin requirements then to all the end-use sectors.

And ended up that they basically were the same throughout the forecasted period. And as we look now at how the CPUC is making its decision, it's basically holding margin requirements constant with an inflator, but that may be applicable for the year or two after the decision.

So, basically we figure that we are correct in assuming that we're basically mimicking what the market is doing in California now by holding those retail distribution costs constant in our analysis.

Another question? Yes, Al.

MR. PAK: Let me just take a couple of minutes because this is an issue that we wanted to raise. And I understand that you don't want to run a whole bunch of scenarios with these models. But there is an important one that we'd like you guys to run, and we're requesting that you do this as part of the 2007 IEPR.

And it has to do with the supply availability and price tradeoff that Bill was describing. On Friday we're going to be filing comments with the South Coast Air Quality Management District with respect to a couple of proposed rules that they have on gas interchangeability specifications that would affect three major supplies in the southern California region, Kern River, local production in California and LNG.

Basically what the South Coast is proposing to do is to change the Wobbe Index value maximums that would be permitted for supplies sold and delivered to sources in the South Coast airshed from the PUC's 1385 to 1360.

I can't tell you what the cost of treating gas out of those other two sources would be to meet that specification, but we have calculated that for our facility and -- Costa Azul, and what we have done is estimate the cost to build a treatment facilities for the full 1 bcf per day of send-out in phase one of the project. Because we just can't see how we can't build a treatment facility for all gas when we're operated at maximums.

And we set our variable cost based on an average presumed send-out of about 759 Mcf per day. Based on those two assumptions, there are two ways that we can bring ECA gas into compliance with the South Coast proposed rule.

The first is nitrogen injection. And moving from a 1385 Wobbe Index to 1360, our costs per Mcf would be about 8 cents. So, on a decatherm basis it's pretty close to 9.

If we were to remove liquids, which is the other method that we could use there, it's 40 cents an Mcf after crediting for the revenues that could be received on the open market for any liquids extracted from the supply stream.

That's a fairly significant change to our cost structure. And I should say at the present time we are not contemplating building any treatment facilities down at ECA. So these would be additional costs and we would need to begin construction relatively soon of any treatment facilities.

It's our expectation that the early supplies that we're going to receive from Indonesia will meet the CPUC standard, but may not meet the South Coast standard. At the present time we don't know what Shell's plans are with respect to the 500 million a day of capacity that they have reserved in the facility.

So, if you factor in treatment costs for ECA. And then you attempt to factor in what the cost of treatment would be for both California production and supplies coming across the Kern River system, that would obviously raise your cost of supply. Certainly makes California a less attractive market since those treatment costs would be avoidable for adjacent markets and markets in the Pacific Rim with which California will compete for LNG. And that will affect both your supply availability as well as your retail price.

So we're asking that, you know, sort of a more objective voice in all of this, that you take a look at what these rules could do to the California gas supply and demand balance, as well as prices.

And we'll be filing our comments, as I said, on Friday. We will be sending you all a copy of how we calculated those costs. I should say that when we took a look at the cost per ton of NOx that might be controlled by moving from a 1385 Wobbe Index value to 1360, we're running somewhere between $500,000 to $2.7 million per ton, which is several orders of magnitude above the cost of any other control measure that we've found in the new draft air quality plan.

So, if you would take a look at that we would really appreciate it. Of course, we're happy to provide you with any data that you might want to look at in performing your own independent evaluation of these costs and the impacts they might have on the California market.

MR. WOOD: Did I understand you then, these costs that you mention here just have to do with treatment of the LNG as it comes into

California? Or is that all supply coming in? I missed the first --

MR. PAK: That's just for our facility, based on our current expectations of the supply characteristics --

MR. WOOD: Okay.

MR. PAK: -- we're anticipating in 2008.

MR. WOOD: Have you a way to differentiate between the different supply sources? For instance, whether it's coming off from the southwest or whether it's from the Rockies or from California-source gas?

MR. PAK: We haven't tried to do it for either California production or Kern River. Kern River supplies have been trending higher over time, and from time to time they violate the South Coast standard, the South Coast proposed standard.

It's my understanding that there are days when they are in compliance, that is they're 1360 or below. But our sense is the fairly large fist costs of building a treatment facility would then be sunk, and that would affect Kern River's interest in bringing supply to California as a first market, as a first order market.

You'd have to ask them what their costs

would be. I think the South Coast suggested to them that they could do some kind of blending with other supplies. We don't think that's feasible, just because of the nature of the gas transmission system in the state. It certainly wouldn't work for us since there's nothing else for us to blend with. And we certainly couldn't find anything to blend with at the volumes and at the precise real time values that we would need in order to bring ourselves into compliance through a simple blending process.

We think it would be fairly substantial. We'd be siting our facilities in Mexico on a pre-approved and permitted site. I have no idea where Kern might put their treatment facilities. If it's at the California border or out beyond the California border, it would obviously be less expensive. But once you try to put anything inside the state, the cost would go up.

MR. WOOD: Well, I can't speak for what we're going to do, but I think it's worth a look at anyway. Leon.

MR. BRATHWAITE: Well, I mean I understand your concerns about this matter, and I know it's a very serious concern. And I do appreciate the seriousness of the matter.

Given our time schedule right now we, as I said before, we are going to do a basecase and full oil price sensitivities, and that is what we're going to do for the natural gas assessment report.

However, any scenarios beyond that we will certainly be able to do that probably in the summer sometime after we have finished with the natural gas assessment report.

And we'll be certainly looking at this Wobbe Index issue. That much I can assure you of. But it will not probably be in time for our assessment report that we'll be doing, that we have to get done before the end of May.

MR. PAK: Okay, great, thank you.

MR. BRATHWAITE: Sure.

MR. TAVARES: Certainly we're going to be talking to the Commissioners about this issue; and we will report back and see what they want to do.

Any more questions -- okay, go ahead.

MS. SCOTCHER: As far as the scenarios go, why did you guys decide on four oil price scenarios? It seems like an inordinate amount of focus on oil price when there are other issues that are serious, like greenhouse gas and something like that.

MR. TAVARES: The Commissioners, or some of the Commissioners have expressed interest in looking at the correlation between oil prices and natural gas prices. So those are the things that we suggested to them, and those are the things that they approved so far.

Again, I think we will go back to the Commissioners and explain, you know, some of the comments and suggestions that we got in this workshop. And we might need to modify them, but, again at this point that's what we have.

MS. SCOTCHER: Okay.

MR. TAVARES: Any more questions or suggestions, comments? Anybody online?

I think we're going to proceed to the end here. Katie, do you have any -- Katie or Youssef, do you have any additional comments on prices, in the price area?

You do? Okay, Youssef.

(Pause.)

DR. HEGAZY: I think that's been covered, this page.

MS. ELDER: But there is, go back, I'm sorry, Youssef.

DR. HEGAZY: Sure.

MS. ELDER: We did want to emphasize one thing. Bill Wood touched on it, but it's incredibly important. You know, NARG is going to out -- these general equilibrium prices -- supply and demand. But one of the things that we want to focus on, or at least the staff results will focus on are going to be the basis differentials, one region relative to another.

And less so -- more so on that than on the aggregate prices. And so you're going to see a lot more, I think, particularly as they add up to results about the relative differences in the regional prices than you're going to see on -- we think the price of natural gas average across the U.S. is going to be whatever the number turns out to be.

They're really going to focus much more on the differentials region to region.

DR. HEGAZY: In terms of the market drivers that affect long-term prices, Bill mentioned the demand and supply and cost. There's a few other things, also, that affect the prices.

One of them is a the long-term technology; and that has two issues about technology.

One is the increase in the efficiency of the usage of natural gas. I mean I've seen that in the electric industry and also in the industrial sector.

And the other one, of course, is the cost of finding and developing and drilling and all other, the processing activities in the future might go down and impact the entire picture.

The second -- the third measure thing is the legislation and regulatory initiatives. Whether it is impact the environmental concerns, or the standardization of the natural gas product inside the United States, or the gas coming from outside the United States. This might have impact on either canceling out or delaying some of the gas that might be important for the supply.

And then how fast or how slow the declining or the phenomenon of the declining in production per dollar spent, and the exploration and finding and developing.

The other -- those are all North American internal drivers, but there's also global issues. The global issue would be more important as much as the reliance on liquified natural gas become evidence and significance.

For example, the EIA has two scenarios in their forecast. One is LNG for the next 20 years will be about 2 Tcf; this is the lowest, 2.5 Tcf. And the highest is around 10 Tcf, 10 Tcf out of the current or projected total demand, which is around 26 Tcf. It's around 30-some percent. So that put the natural gas into the same ground with oil; that says a lot of dependency on the national market, international market and the global market.

There's a security issue; there's supply interruption issues with every international global unrest. And, for example, the issue that Katie mentioned about the Russian nationalization of the gas industry. There's other more wider trend, for example in the Middle East, in which the countries want to develop their resources by themself, away from the major world experience, more skillful, more technologically advanced companies. Can they deliver, because as you know very well the gas and oil reserve in this area is probably the majority in the world -- can they deliver on developing timely these resources.

That's another risk.

And, of course, the more you rely on the global market the value of the risk dollar become very very important issues.

Oil supply, let me go back to oil supply later on because there's an important slides that we will --

When Bill talked about supply and demand, this picture present how supply and demand together impact the prices. The red line is the natural gas prices over the years, between 1949 all the way to 2005.

The blue line is the natural gas production, local production in the United States. And what is that color called, purple? The purple -- magenta -- is the consumption. As you can see all the way till 1988 the two supply and demand are very much in synch with each other.

From '88 on the consumptions take over and become a lot higher than the supply; and the gap keep increasing. By 1995 was the highest gap, which is around 3 Tcf. Now it's going down a little bit, but we still between 2 to 3 Tcf a year of gap in the United States.

And as you can tell, how the price

volatilities and the price trend, increasing trend, are neck and neck with that growing gap. So supply and demand is, especially inside the United States, the major --

MR. BRATHWAITE: Those prices (inaudible) nominal prices?

DR. HEGAZY: Yes.

MR. BRATHWAITE: Okay.

DR. HEGAZY: This is an interesting slide also. It shows several things. One is the movement of natural gas prices with several petroleum products. And this is in dollar per MBtu. So the oil is converted into dollar per MBtu equivalent using the well known ratio, which is 5.8 to 1 or 6 to 1. It's usually between these two rates.

The blue line show you that most of the time it's around probably 80-some percent of the time that gas prices is traded or priced in dollar per MBtu equivalence, at a discount from oil. Although there is a strong relationship, as the graph shows, or the movement of the two prices moving together, but prices most of the time are traded or priced at a -- in a dollar per MBtu equivalent again, lower than the oil or petroleum products.

That's why this link between oil and gas, and that's why these two scenarios that the Commission is going to do, in order to test the model and in order to see how the model and how the prices react to the higher gas and lower gas are reasonable assumption from that.

As we said, the gas prices have increased by more than oil. This is in percentagewise. But not in dollar per MBtu-wise. So the value for the price of gas in dollar per MBtu versus the oil dollar per MBtu, the gas is always most of the time treated as the picture has shown, at a discount. Very few times was treated at that premium compared to oil.

And this is actually because there is a shift in consumption from oil to gas, specifically in the northeast and in the midwest. That's why the Rockies' gas has been developed to, or shifting to the northeast and the midwest, is there's a shift, especially in the industrial sectors, and there's -- heating demand from -- electricity. Which means from oil to gas basically. And with that in mind, still gas prices is treated $1 per MBtu lower than (inaudible).

And the volatility continue to increase. And there is two theories. One is the supply gap, which the one I believe this is the most fundamental issue, that creating these volatilities. And then whether the financial trading activities that has been, you know, a lot more active, a lot more in volumewise in the last five, six years.

I have seen a lot of studies and they show other industries, not necessarily in the gas or oil, which say that's usually financial -- feed off of volatility. They don't feed volatility. They don't create volatility, they actually feed off of it. So supposedly you turn down the level of volatility. But that is something empirical and it hasn't been really estimated -- or studied at length in the gas industry.

There's two important questions people are asking, also. One is there a floor, can we speak of a floor in gas prices. And if we can, is it a $3.50 or is it a $4 or higher. And I have seen the two ranges. And the people who have range has every possible scenario in their mind to believe in their numbers.

And also is there a ceiling. Usually, and this is one of the drivers that Bill didn't mention, I didn't mention, either, which is the cost of new entrants. What is commonly called the contestable cost. You know, is there another field out there than can, at a $7 per MBtu gas, can come in and replace much of that gas.

And also with regard to the floor, is $3 is sustainable, is a level that will increase demand immediately or in a very short period of time to bring it back to a more reasonable number.

So, if one want to create two scenarios in order to see the floor and the ceiling of these prices, I just came up with a list of issue that we can use if we want to create these two scenarios.

The usual one, or the usual culprit is the oil prices. If oil prices continue to decline. One thing, also, I didn't mention about oil supply, oil for a long time, all the way to 2000, 2001, 2002 was moving up and down around the $25 area. That has started probably after 1979, 1980, after Iranians and the oil prices reach $40 and $50 and $60, and the consumption side and the supply side reacted to that. In which a --

capacity created, and especially OPEC capacity created and continued all the way to early 2000. That what made the prices goes ups and down, but around $25 per barrel.

Since then, since 2002, prices has never -- prices ups and down around $50. And last year it's $60. So, there seem to be from 2001, 2002 there's a paradigm shift in the oil industry. The whole structure changed. Because one thing is that the spare capacity is gone. There's very little spare capacity, especially in OPEC. OPEC is the residual demand producers. They serve for the residual demand.

Everything else is produced is consumed. OPEC is -- OPEC producer don't consume much, so they serve the residual demand. And any excess capacity from their production about that residual demand is good news for the industry, or for consumer.

That spare capacity has been lower than 3 percent even during the peak months of consumption, of production.

So there seem to be a strong shift on the structure of the oil industry. There similar structure shift in the gas industry, that's a strong question to others. But those are the scenarios that I thought of in order to create these two levels of gas prices in which the rational expectation of future gas prices has to be in between those.

Lower oil increase in production, a surplus of LNG, demand erosion continue and industrial and more efficient use of gas in the electricity sector. The climate initiative impact will be minimum.

And one thing one should address, also, is the internal issue of the standardization of the products and the impact of that. But that's usually probably if imposed it would contribute to the high price scenario because it reduce production.

And for the high price scenarios the most important one, of course, is by 10, 15 years from today, if the Alaskan and Canadian pipeline projects would be delayed further because this would supposedly bring around 2 Tcf, which would definitely impact prices, or put a downward pressure on prices immediately.

Any question?

MS. ELDER: Yeah, I just -- let me add

just a couple of things to sort of, I think, close this off or finish our kind of thought process.

Is staff has worked hard to develop the assumptions for the reference case. They've got the modeling going, almost, not quite, but it's about to get going. A few little things, details to clean up to get that going.

And then the assessment then is going to not only present these reference case results, but try to identify the things, the key assumptions that could cause reality to be different than the reference case.

What we want to do is try to get the most robust list, if you will, of those alternative assumptions put together so that we can discuss those, admittedly qualitatively because we can't run a lot of extra scenarios. We're not sure we can get more than the four that we've been instructed to get done.

But we want to try to address those issues. And what you see in our summary kind of presentation at the beginning, or our introductory summary, and then with respect to each section, are our preliminary ideas. And they're preliminary pending input from all of you, and the additional stakeholders. But our preliminary ideas of what those issues are that could have a big impact on the outcome that could cause reality to be different from the forecast.

That is where we're looking for additional input. Tell us if you think the list is right. If you want to put additional things on the list. Take things off the list. Characterize it. That's what we're trying to pull together.

Anything else?

MR. BRATHWAITE: I got a question.

MS. ELDER: Leon has a question.

MR. BRATHWAITE: I will try to be brief, okay. You know, Katie or Youssef, you can comment here, in 1980 and '81 oil prices stood around $40 a barrel. And I think every analyst at that time was projecting maybe $100 oil by 2000, okay.

I think any analyst who had projected $15 oil say by 1986 would probably would have been fired. I think you would agree with that.

But, as we know and we look back upon it, we know that oil prices did collapse in the mid '80s.

I was wondering, now that we've seen oil prices at $60 a barrel, and I think everybody is saying it's going to be sustained for as far as the eye can see, I was just wondering what is different now than it was in 1980 or '81 when eventually prices, which was at a sustained high level, did eventually collapse. What is different now?

MS. ELDER: Someplace there's a PhD dissertation being written on that issue. And Youssef and I could probably come up with the outline of one in an hour probably total, if that long.

I'll suggest a couple things though like Youssef had, because I'm sure he's got some ideas. One thing that's different, one thing that's different that's actually really important is, Youssef had it on a slide earlier and didn't really highlight it very much, is the value of the U.S. dollar. And that's one of the things that happened two years ago and three years ago, was oil prices began to rise. A lot of the nations that are exporting oil to the U.S. were overjoyed because they had seen the value of the return dollars that they were getting from selling oil in U.S. dollars, as it has done pretty much worldwide, they were seeing their revenues shrink.

And so one of the broad theories is that even though OPEC had a target at the time of $22 to $28 a barrel, OPEC countries were very happy to see $40 a barrel because it just corrected the decline of the value of the U.S. dollar. It's that simple.

The other thing I would probably point to that's different now than it was 20 years ago or 25 years ago is the value, the total value of the world economy and the cost of oil as a proportion of the total value of the world economy.

I think we usually talk about that in terms of U.S. GDP. There's been a lot of notice taken by various people in the Federal Reserve, including former Chairman Greenspan and current Chairman Bernecke that the current -- the cost of oil or cost of energy in general, as a percentage of GDP, is lower today than it was 25 years ago. And that's one of the reasons why prices can be sustained without having a huge negative impact on the economy.

So, those are two things I can identify quickly that are different, that are really important.

DR. HEGAZY: Right, and there is another important issue about the structure of demand, the global demand versus the U.S. demand. At that time probably the structure of United States demand was similar to the structure of the global demand right now.

Right now the United States has -- because of that prices in 1980 the United States has been able to diversify its demand in a lot more stable way. So oil is not that predominant in -- it's still in transportation, but it's not that predominant in electricity generation and in heating and in other things.

Therefore, United States is able with oil prices has been sustainable at $50 in the last two or three years. We haven't seen any recession because of that. At least in the short term. And it doesn't seem to be the case in the long term, and from all that I have seen.

But that is in the United States and probably Canada, and maybe western Europe. But now we have China and India, and the rest of Asia and the rest of the world that consuming oil as high in percentagewise and in share-wise of their total energy consumption, as United States probably was in 1970s or late 1970s.

So, to add to your question, one might ask is, will the $60 a barrel of oil, will that have the same impact in their consumption or demand structure as it does in the United States. Will this country be able to reduce their consumption in commercial and residential, and also in transportation very soon.

United States still have a problem in terms of the transportation industry which we still have cars that a lot less efficient than the western European and Japanese car. And so with $60 or $70 per barrel would impact that in the near term, or at least in term that we shift into a more efficient transportation modes. In public transportation there's a lot of, you know, natural gas vehicle movement around the country. And that started in California a long time ago. And has some impact.

But I read somewhere that if the United States was able to move to a more efficient car, similar to the one the Japanese and European, the transportation demand would be reduced for oil by 10 percent. And that's a lot of barrels.

So, the reaction of the global economy

to a sustainable higher oil prices there is, I would think in my own view there's a significant potential to be similar to the reaction that the United States economy and demand structure has done in 1980, which was tremendous.

MR. FORE: Let me add something to what Leon's question. You know, during that time period from 1970 you had the ANS come on, which was an elephant field, and so you had more spare capacity. You had the North Sea come on during that timeframe, which was more spare capacity.

And then you had within OPEC, they took back their production from the Seven Sisters at that time. And the key became deliver, you know, each one was trying to establish their dominance, so they put in -- production capacity, which made that great big spare capacity that you don't see today.

And I guess the question becomes to you, try to go down, if we find another elephant field someplace in the world, it will probably drive the price down because you'll get the spare capacity. But if you don't, maybe it'll stay at $60.

But you had a lot of production coming on there after 1970.

DR. HEGAZY: And to go back to the modeling issue, and this is one that I remember that trace every model, been in modeling almost all my life, is you started with oil prices. You know if you continue with this oil price certain things will happen.

And then there will be a pressure in oil prices to change either up or down. How do you model that. Do you start with certain oil prices, and then after five years do you start with a different paradigm in oil prices. That takes a lot of time and effort and all of that.

The only way usually, and specifically traders type, and institutions and companies handle this is through hybrid modeling in which the stochastic or the random is nature of everything is assumed.

So you don't come up with a reference point forecast or just an expected value of the forecast. Because expected values has a probability of having, say, 50 percent if you're lucky.

If oil prices goes to 70 percent, how much risk your oil business would be exposed to. That is something usually every institution has to look at.

That's why moving in the future into a more hybrid stochastic modeling forecast, you know, is a lot more -- I know is strategic move, but that's what the industry's doing.

MR. TAVARES: Thank you. Okay, any last questions before we end this session? Anybody on the line? No.

Okay, what are the next steps. Any comments, suggestions that you want to make, we can submit it to us by Friday, this coming Friday. The docket number is 06-IEP-1D. Or you can email it to docket@energy.state.ca.us.

Now, our schedule is pretty tight. We have a draft report that we need to make public for comments by May 25th. That's our date.

And then we're going to have a workshop, or actually a hearing, an IEPR Committee hearing on that assessment on June 7.

So, as you can see, our schedule is very very tight. But we are moving forward, that's what we have. And we received all the comments and suggestions.

And I thank you for coming.

Any comments, any last things?

Okay, well, we are adjourned then. Thank you very much.

(Whereupon, at 1:00 p.m., the staff workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Staff Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 4th day of April, 2007.