BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket No.

NATURAL GAS MARKETS CONFERENCE : PL03-6-000

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Commission Meeting Room
Federal Energy Regulatory Commission
888 First Street NE
Washington, DC

Tuesday, October 14, 2003

The above-entitled matter came on for conference, pursuant to notice at 9:15 a.m.

REPORTED BY:

JANE W. BEACH

APPEARANCES:

PAT WOOD, III, CHAIRMAN PRESIDING
COMMISSIONER WILLIAM L. MASSEY
RICHARD D. KINDER, Vice Chair, NPC Committee on Natural Gas
JERRY LANGDON, Chair, Coordinating Subcommittee, NPC
MARK A. SIKKEL, Chair, Supply Task Group, NPC
WILLIAM N. STRAWBRIDGE, Assistant to Supply Chair
GERRY A. WORTHINGTON, Leader, Resource Subgroup
JOHN HRITCKO, JR., Leader, LNG Subgroup
DAVID J. MANNING, Chair, Demand Task Group, NPC
HARLAN CHAPPELLE, Assistant to Demand Chair
KEITH BARNETT, Leader, Power Generation Subgroup
DENA E. WIGGINS, Leader, Industrial Utilization Subgroup
SCOTT E. PARKER, Chair Transmission & Distribution Task Group, NPC

APPEARANCES CONTINUED:

RONALD L. BROWN, Assistant to T & D Chair

MARK T. MAASSEL, Leader, Distribution Subgroup

RICHARD C. DANIEL, Storage Subgroup

BYRON S. WRIGHT, Transmission Subgroup

P R O C E E D I N G S

(9:00 a.m.)

CHAIRMAN WOOD: Good morning. This open meeting of the Federal Energy Regulatory Commission will come to order. We want to first of all thank all the folks from the NPC work group who are here today to discuss their very timely and important report.

We want to thank the members of our Staff, particular Andrew Soto from my staff, and all the rest who have organized today's special focus on the natural gas market issues raised in the NPC report.

As you know, last year we began a new tradition -- twice is a tradition around here, so this is the second one, of having a focus on the natural gas markets in October of each year, and I suspect we'll continue that in the years to come, much as we focused on hydroelectric issues in the December timeframe.

This year, this topic has such a broad impact that we dedicated an entire day to it. This is not to say that there are not other natural gas issues that are of interest. As a matter of fact, we have left open the last hour of the day for an open forum on non-NPC issues. It is a time for us to focus on general issues in the gas industry.

So many of those are wrapped up in this report.

It's a very appropriate way to break into these issues.

I'm going to ask Bill if he has anything to add before we jump in.

(No response.)

CHAIRMAN WOOD: Rich Kinder is Vice President of the NPC Committee on Natural Gas and Jerry Langdon is the Chairman of the Coordinating Subcommittee for the NPC. At this time, I'd like to turn it over to you gentlemen, and let you all break it open for us.

MR. KINDER: Thank you, Mr. Chairman and Commissioner Massey. It's a real pleasure to be with you today.

I am really here representing literally hundreds of people who worked on the recently-released NPC Gas Study. We've titled this Balancing Natural Gas Policy: Fueling Demand for a Growing Economy.

As most of you know, this represents the culmination, really, of a year-long industry effort to evaluate the long-term balance of natural gas supply and demand. We appreciate the opportunity to share the results with you today.

We also look forward to a dialogue that I hope will develop today in terms of questions and answers from you and from anybody else. I think our feeling is, Mr. Chairman, that the primary purpose today is to really initiate the first of what I hope would be many necessary interactions between the industry and the Commission as we strive together to move to a balanced future for natural gas.

(Slide.)

MR. KINDER: As our first slide shows, this is just a little background on the National Petroleum Council. Of course, it's a federally chartered, privately funded, advisory committee.

It was really established shortly after World War II. It exists solely for the purpose of providing advice to the Secretary of Energy, and operates under the Federal Advisory Committee Act. This means, among other things, that all of our activities are open to the public.

The Council is composed of about 175 individuals from industry, government, academia, and other backgrounds who serve at the invitation of the Secretary. I've been in this industry a long time, and this is really one of the most broad-based groups of participants, so I think that when you listen to what this study has come up with, you may agree or disagree with it, but it has been certainly vetted across a whole wide spectrum of the industry.

(Slide.)

MR. KINDER: I think the study could not be more timely. I won't bore you with the details, but Secretary

Abraham requested a new study on natural gas in March of last year. We thought it was very timely at the NPC, and we're delighted to take up the task.

As the quote from the request letter illustrates, the Secretary wanted a new study on natural gas to examine the potential implications for new supplies, new technologies, to look a perceptions of risk and what he termed other evolving market conditions that may affect natural gas supply, demand, and delivery through 2025.

In addition, we were asked to provide advice on actions that industry and government could take to ensure adequate and reliable supplies of energy for consumers. We really took this charge seriously and looked very seriously at what these actions should be.

I think you will see that as the presenters talk today. Obviously, as you know, NPC studies are conducted through voluntary resources provided by member companies, and we organized ourselves as shown on this slide.

(Slide.)

MR. KINDER: We had a Committee on Natural Gas, which was composed of a Vice Chairman from each of the three areas. I happened to chair the T&D part of it. Lee Raymond chaired the supply side, and Bob Cottell, the demand side.

But the real work was done by Jerry Langdon and the Coordinating Subcommittee. I'm not going to say that they should get the blame, but they should certainly get the credit for the good results. I'm going to turn it over to Jerry in just a couple of minutes, but let me just say this:

Again, I want to emphasize that this was a major integrated effort of all sectors in the natural gas market. We had consumers, including power generators and industrials. We've had a lot of cooperation.

There wasn't always agreement on every issue. It was a lengthy process, but we had the input from everybody and reached an agreeable set of facts and positions at the end.

We had participation of producers, including independents and majors, U.S. and Canadian, and we had various representatives of infrastructure, including long-haul pipe, storage and distribution. I think our basic conclusion -- and you're going to hear this throughout the presentation today -- is that North America will not be self-reliant for it natural gas needs, if we continue to gain the benefits of natural gas for the economy and the environment.

So the effort really revealed the need for a complete solution, and it revealed the perils, I think, of the piecemeal approach. We believe we need reliable, flexible infrastructure, we need efficient markets, we need flexible demand, and, of course, we need diverse supplies.

That all sounds very good, but I think the applicable question today probably is, so, you're going to talk to us about supply and demand, and take an analysis of the broad side of both sides of the equation. What is there for the FERC?

Obviously, the role of the Federal Energy Regulatory Commission is huge in this. We hope that today will establish that there are numerous things that we hope industry and the Commission together can cooperate to assure that the best scenario for natural gas in the future will be achieved for this country.

We found, for example, Mr. Chairman, that though needed infrastructure over the period is less than that proposed in the results of the '99 NPC study, it's not atypical to reach an industry trend. We believe that over 57,000 miles of new pipeline facilities will be built over the study period, which extends from now till 2025.

We think an average of $8 billion per year will be invested in new and existing infrastructure. A lot of that, of course, is capital for expansion, but we also have extensive capital that we would call sustaining capital that's got to be spent over the next ten, 15, 20 years, to keep our system in shape and to assure safety, reliability and its ability to meet future uses.

In addition to miles of pipe, we think storage is going to play a critical role, particularly as we attach new sources of supply. We think it's going to be necessary to build over 700 Bcf of new storage capability during this period, and we think it's going to be necessary to enhance existing storage resources where it's feasible.

So what we hope we will be able to do is work together with this Commission to achieve certain things. We hope that in a very generic sense, we will be able to get prompt permitting and project review. I know that this has been a real cause of yours, and we need this for infrastructure to attach available supply, specifically from the Rockies, we need permitting and project review on a prompt basis for new LNG terminals.

You're going to find LNG is a very important part of what we're talking about today in the supply perspective. Not only do we need permitting for LNG terminals, but we need it for the pipeline connecting facilities that are absolutely essential to integrate those LNG facilities into our national pipeline grid.

I think that in a broader sense, we need to improve all of our infrastructure project permitting and review processes. We need to get collective goals set up front to get all parties and agencies involved.

I know this has been another objective of yours, and obviously we need to address issues and to weigh alternatives, but we need to move projects through the various processes in a timely, efficient, and cost-effective manner. I guess our overall goal would be that projects that enter the process and successfully exit such process with a FERC Certificate, can then proceed to implementation according to the established conditions of the approval, with minimum delay.

We hope to encourage new tariff services. I hope this will be discussed throughout the day. We need these to meet the changing character of the demand we forecast over these next 20-plus years.

We think, as I said, that we need more flexible storage services. We need new facilities in the storage area, and we're going to have to redesign some of our existing facilities.

What we'll be seeking and hoping to achieve over the next period of months, or as quickly as possible, is some kind of regulatory certainty. We seek an environment that facilities infrastructure investment.

I think that you will find that the capital markets of this country are not going to allow companies like ours to put $8 billion in the ground every year for the next 20 years, without regulatory certainty.

We also need regulatory certainty with respect to parties' abilities to enter into long-term contracts. These facilities, whether transportation or storage, will just not be built without long-term contracts.

And we would also request that the FERC become the official lead agency for coordinating proposed interstate natural gas infrastructure projects, coordinating with appropriate federal, state, and local agencies. We think this would be an important step towards streamlining the process for permitting.

Finally, and very generically, we hope to have FERC's support for market transparency, for timely and accurate data availability, and for allowing the markets to work efficiently.

That's an overview of the world as we see it. With that, I'd like to turn it over to Jerry, who has done a fantastic job of chairing the Coordinating Subcommittee. Jerry?

MR. LANGDON: Rich, thank you very much. Importantly, thank you for the commitment that Kinder-Morgan, Exxon, Keyspan, and others have made to this work. It's been a significant contribution.

I'd like to say at the beginning, too, that this has been a terrific government-industry partnership. We've had literally people from the Department of Energy at the very highest levels. The Department of Energy participated not just passively in this work, but very actively in this work. Everybody from Bob Card, who is the Deputy Secretary, has been very engaged in this process.

Mike Smith has been very involved and others. More importantly, Mr. Chairman, Andrew Soto has made a tremendous contribution to this effort. For that, I very much appreciate your willingness to lend his intellectual support to this effort.

I want to just reiterate what Rich just said: Supreme Court rules are in effect. We will stop whenever you have a question, and we will make sure that those questions get answered.

We do have a fairly lengthy presentation. I think that if you have the patience to deal with it, there will be kind of a soup-to-nuts approach here, and we'll get to it.

Finally, I want to thank you, Mr. Chairman, for this forum. This has been the first opportunity where we have really had a live body like the FERC to sit down and walk through what some of these policy objectives are, and our recommendations.

So this is really a good opportunity for us, and we will, by the way, have additional data available to support what we're doing and what we're going to tell you today. That will be out in probably the next week or two. We hoped to have had it ready today and we're just running a bit behind, so we'll have it quickly, the integrated report.

I have the enviable responsibility here of the first couple of slides, of having the ability -- I get to tell you what we're going to tell you, and I get to come back at the end and tell you what we've told you.

(Slide.)

MR. LANGDON: I think what we're going to tell you today is that we've taken a hard look over 18 months at the natural gas industry. And we think there is a fundamental shift in the way the industry has operated and will likely operate in the future.

We think the gas markets have changed dramatically in the last 15 years since restructuring; that demand has grown considerably as a result, in large part, of electric power generation in this country, but we think demand remain strong, and we'll be looking at natural gas to fill a big piece of that.

A bit more difficult thing for us to talk about is the fact that while demand has grown, we think domestic supplies, drilling activities, and the response to drilling activity has now begun to plateau. We're going to find ourselves in a situation of having more and more difficult times trying to keep up with growth in demand, or even existing demand.

Then, lastly, in particular, if you look at what's happened in the last three years, in particular, tightening supply and demand balances have begun to create not only higher prices, but more price volatility. We think that in competitive markets where you have tight supplies, that this volatility is likely to become something that we have to deal with.

with.

We have to learn how to use tools to mitigate. It's just going to be a factor of everyday life going forward.

(Slide.)

MR. LANGDON: Importantly, one of the things you will not see in this report, is a model of the status quo. We think the status quo of conflicting policies at multiple levels of government that favor gas usage over other fuels, is hindering efforts to advance available supply and in places, has increased restrictions on the ability of consumers to respond. It's simply is a possible that just is not sustainable.

The study is based on the knowledge that the market -- suppliers and consumers -- will respond over time. I think it's important to understand that that scenario, the status quo scenario, is not in here.

We haven't looked at it. The truth is, we peeked at it and didn't like what we saw, so we went back and took another look at these two paths that we're going to show you. One is near the status quo and has some elements of the status quo; the other is more of a balanced approach.

What I'm going to do on this next slide is talk about the two cases we studied. You should note that even in the worst case, or the reactive path that I'll show you in the future, it does assume that Arctic pipelines will get built; that there will be substantial amounts of new LNG imported.

Access to the lower 48 for new exploration will improve, and that energy efficiency will increase, and that additional generation capacity will be built.

(Slide.)

MR. LANGDON: These are the two approaches that we looked at. We framed our analysis by considering two scenarios for public policy at the local, state, provincial, and federal levels. I think, importantly, a lot of what we have to say is implementable or has implications at the state level, but there are also federal issues as well.

The first is the reactive path where we continue to experience conflicting policies, with decisions made in reaction to advances as they unfold. Then there's a balanced future where public policies at all levels are aligned to benefit consumers.

This study has a lot of background, and, as I said, a lot of good detail. We will have the integrated report, which will have a lot of that information available in the next week or so.

Then, following that, there will be a taskforce study group. Each of the task groups has written its own report and those will really be the unvarnished opportunity to look at a lot of the data that underlies the recommendations and conclusions we came to. That will be coming along very quickly.

Most importantly, I think you should recognize that in both of these cases, protecting the environment was a given. We didn't back off of the environmental standards, and, in fact, we continued them forward.

(Slide.)

This is a sort of a bottom line. The task group chairs will provide you with the details. But the reactive path results in higher consumer costs and greater economic risks, in contrast to the balanced future, which is the lower priced environment.

You should note that these are average annual gas prices. This doesn't take into effect the swings that we would have, volatility swings, way outside this line in all probability and it's calibrated in 2002 dollars for the length of the process.

With that, we're going to give you the background on why we think we've reached this point in our history. I'll turn it over to Mark to start that process. Mark Sikkel is vice president with Exxon-Mobil and chairs the supply task group.

Oh, I didn't do my last slide. I'm sorry.

(Slide.)

(Laughter.)

MR. LANGDON: That one crept in. Let me go back real quickly. We do think the recommendations that you're going to see throughout this involve these areas we'd must improve demand flexibility and efficiency, increase supply diversity, sustain and enhance our current infrastructure, and promote efficient markets. The result is obviously higher economic growth, higher employment, and stronger industrial activity. I think it's worth noting that the balanced future case is an and-and-and approach. It includes all of these. It's not a cafeteria approach. You have to do them all.

Or said differently, our model assumed that they all improved in some way to be able to get to that balanced future. With that, Mark, sorry about that.

MR. SIKKEL: Thank you.

(Slide.)

MR. SIKKEL: Just a few other introductions until I get into it. John Hritcko with Shell will be covering the LNG portion of the presentation and was a big asset to our supply effort.

Next to John is Bill Strawbridge, my assistant for the past year through the process. To his right is Joe Worthington, also with Exxon-Mobil who lead the resource efforts. If I get in trouble, two of those guys can help me here a bit. Obviously lots of other folks worked on this study. We're just going to try to represent that work today and I sure would encourage your questions because I'm going to talk about our results but I'm also going to try to lead you through the process we went through and that may stimulate some questions as to just how we went about it.

(Slide.)

MR. SIKKEL: This first slide summarizes our approach. We set about to conduct a comprehensive review of the North American resource base. All that was really geared around was, you know, how much gas are we really working with in North America?

We also wanted to look at historical production performance. We wanted to look at the existing basins, how much we produced, what does that tell us about the amount to be produced in the future? We wanted to look at new supplies because we've got a long term outlook here, 20-25, we assume that some of this will come into play. They certainly did.

When we looked at those things we also wanted to consider the effects of advancing technology and how that might impact new supplies as well as the regulatory environment and we did some focused work on the access issue.

But fundamentally what we were about was the production outlook, how much resource did we really think was going to be commercialized and produced and we'll show you those figures.

(Slide.)

MR. SIKKEL: To do that, we had a very extensive group involved and had a lot of industry support as shown in this organization. We had a supply task group which was where my responsibilities lay. Then we had several subgroups, resource as I mentioned, led by Exxon-Mobil on the conventional resource side and Anadarko on the non-conventional side. Shell with LNG, Shell and Texaco led the technology subgroup. Burlington led the environmental regulatory access work. The arctic work was totally led by the Prudhoe producers. It was very much a collaborative effort, a consensus process and contributions from a lot of different directions.

(Slide.)

MR. SIKKEL: This next slide gives our bottom line outlook. This is the overall slide projection including some history. Obviously that top line matches demand which is what we're all about for the U.S. and Canadian demand. You see if you look at the components that the Lower 48, which is really the blue wedge at the bottom, is pretty flat in this outlook, if you go back to Jerry's price projections. We've got quite a robust price projection and that keeps those traditional areas flat in their production outlook over this time period.

Canada, which has been really rolling over the last decade in helping to meet some of our U.S. gas requirements, really plateaus and stays pretty flat through the outlook period as well. The growth in the long term comes from the arctic projects and LNG.

We'll come back to some of these components but those splits and the diversity of supply reflected therein are pretty important. I guess I should also acknowledge the growth that you see in the deep waters of the Gulf of Mexico and also in the Rockies that help offset the decline in some of the more traditional areas.

(Slide.)

MR. SIKKEL: Overall for the supply work, we landed on three significant findings for the work. The first related to the North American producing areas that they will provide a significant portion of the long term U.S. gas needs but won't meet the projected demand. This was one of the fundamental questions we set out to look at. We're saying this really even in the robust price environment that those projections reflect and so I think it's an important finding.

We also commented on the fact that increased access to resources could provide some benefits to consumers. Basically all we're saying there is, if there's value in better utilizing those resources and providing access to some lower cost resources.   I'll talk more about that.

Finally, we had a finding about the new sources that could meet a significant portion of new supplies but also high cost and long lead times and we're facing barriers to development of that need to be overcome and we'll talk about some of our recommendations on all these.

(Slide.)

MR. SIKKEL: Our overall recommendations are summarized with these three. They're all geared really around reducing impediments to the way markets work in getting on with the job. You want to increase access and reduce permitting impediments to the lower 48 resources. We think we should see enabling legislation by the Alaska Gas Pipeline this year to help facilitate that project.

Then to process LNG permit applications as quickly we can, we set an objective to see if all those permits couldn't be handled in one year or to for those projects. We'll talk about some of the specifics behind that further on.

(Slide.)

MR. SIKKEL: This next slide gives you a little road map on how I plan to go through the rest of the discussion. I'm going to start with production from traditional North America basins. To do that I want to do a little bit about the work really on the resource bases, talk about production evaluation, talk about our cost estimating work and how we look at technology. That all leads to an assessment of the commercial resource and the production outlook and we're going to have about a few comments about access to arctic gas and LNG.

(Slide.)

MR. SIKKEL: The first major section is the resource base.

(Slide.)

MR. SIKKEL: This slide is kind of busy but it reflects an important methodology that we went through to assess the resource base. We had to look all the components' proved reserves, growth that are on people's books today, growth to those proved reserves we know from history that we will see growth in existing fields in terms of reserves and production. We had to make estimates as to what that would be.

Then, finally, new fields, what's undiscovered out there that can contribute to the outlook. We also had to assess the cost of finding, developing and operating those things and use that to develop the commercial resource estimate by modeling the supply-demand balance.

On proved reserves we took the available data. We didn't just take it as it stands. We did decline curve analysis from today's production levels to confirm as today's production declines as we expect, do you get something close to that proved reserve number? In fact, we did. So we felt like that was good data to use. We looked at growth of proved reserves in existing fields. Basically what that was about was projecting recoveries per well in existing fields, extrapolating them to some economic limit and then deciding basically at that point that there would be no further growth in using that kind of methodology to arrive at a growth figure.

Finally we did work on new fields that was statistically based as to the field size, distribution, chance of success, all this work was done on a basin by basin basis with somewhat different methodologies for conventional versus nonconventional gas but quite as specific process. We used the best data we thought available in the public domain, the USTS assessments, the NMS assessments, the Canadian gas potential committee assessments.

These were assessments where there was a clear methodology in which we could understand where the numbers came from. We can interact with the people as to improve our understanding of the numbers so we thought that was the place to start and then we used historical cost information for a number of sources.

We used those in a series of industry workshops to basically validate this data prior to our own use.

(Slide.)

MR. SIKKEL: In that workshop process is really summarized on this slide. I won't go into a lot of detail on it but we had a core resource team that was varied in size, say four to eight people in the center of the slide. To the left we have some best practice teams that looked at the methodologies to ensure whether we were using the best methodology and a consistent methodology as we looked at all the basins.

Then we had the series of workshops shown across the bottom of the case. In some of the cases multiple workshops where the group felt that additional discussion was needed to reach conclusions on the resource base. Then finally we used all that in the model run process.

It was quite an extensive process, one we forget a bit, because a lot of this work was done six months or so ago, so it was early in the process.

(Slide.)

MR. SIKKEL: It led to this kind of information. On the left we show 17 regions and we really consolidated the technical resource base information until 72 regions were evaluated and this was a summary of that information.

To the right we show nine top areas in terms of undiscovered technical resource. It's probably interesting to look at what some of those are with Alaska being first, the Gulf of Mexico second, Rockies third, with a big nonconventional component, Western Canada, and so forth.

So when we talk about meeting growth from the Rockies and the Gulf of Mexico, this is why because most of where we assess that undiscovered potential would be in those areas.

Also noteworthy is what's missing from this chart, some of the traditional areas of west Texas and the midcontinent area where a lot of gas has come from in our history. This helps give you a sense on the kind of information that was used in the mode.

(Slide.)

MR. SIKKEL: I summarize all that in terms of the total evaluation of the technical resource base. We show the lower 48 on the left in this slide and North America on the right. You can see the lower 48 is split out between these components of proved growth, new field discoveries and nonconventional.

Relative to the '99 assessment, our 2003 assessment is fairly close in the lower 48 although we did use lower figures for the growth component because of new information on the recoveries per well that we saw in recent history. Then if you look to the right and compare to North America in total, the Canadian numbers are down a bit. The team saw less gas in the far north Arctic offshore. They also saw a smaller component of nonconventional gas in Canada.

Still, all of these assessments are over 2,000 TCF, which is a lot of gas. The issue is not so much resource base. It's what it costs to get it, what it costs to produce it, what kind of recoveries you get from the wells when you produce it. That's some of what I'll get into in the next section.

But that's the essence of our story around the resource base.

CHAIRMAN WOOD: Why was the Mexico slice missing in the '99?

MR. SIKKEL: We just didn't assess Mexico in '99. We also in our overall evaluation just treated Mexico as a net importer into Mexico during the study period so the assessment we did really didn't have a lot of bearing on the analysis this time around either.

It was lower than what was done in '92 because of some reductions in proved reserves and then, consequently, subsequent reductions in growth of proved, as well as the undiscovered piece. It didn't play a big part, it just wasn't assessed in '99.

Moving forward, the next section is production performance.

(Slide.)

MR. SIKKEL: Again, the methodology here is important. We analyzed the production performance on all gas wells drilled since 1990. There's a lot of data available in this regard. So it provided a lot of useful things to analyze. We looked at some significant performance parameters for each producing basin as to what kind of recovery trends we saw in the wells, what kind of trends there were in initial production rates, what kind of decline rates -- we evaluated the rate of base production decline from existing wells and we also analyzed the production response to increased drilling activity in the 2000 - 2001 time frame. I'll show you a bit of that.

All of this trying to help us get our mind around, well, what should you expect from additional development and how do we calibrate the kind of production response we might see?

(Slide.)

MR. SIKKEL: These next slides are a little hard to see but they get into that a little bit. The one on the left shows the recovery per gas connection which shows a clear decline over the past ten years. This isn't a new phenomenon. It's just part of the characteristics of a maturing resource base that, over time, you're going to see directionally lower and lower recoveries over time. The western Canadian decline is more significant than the lower 48. The recent years are really biased by a lot of low rate shallow drilling that has really helped to hold the Canadian production figures up. But the recovery per connection is falling again. This is just indicative of a maturing resource base, something we need to consider in our forward outlooks. We have this kind of information on a basin by basin basis and we used it in projecting the forward outlook.

MR. HEDERMAN: Mr. Sikkel, could you call that a little more on that relating to Canada a more severe decline rate path versus the lower 48. If it's a function of maturity I would expect it to be the opposite. I was wondering if you were going to get to that later. That's fine.

MR. SIKKEL: I don't know that I have anything to add. From a maturity perspective it's not shown in these slides. I just know that when you look at the wells drilled in the last three or four years in western Canada, they increased dramatically, that it's a lot of very shallow, low-rate, relatively low-risk production.

So I think that makes this more precipitous than maybe it really is. Beyond that I don't really have anything to add relative to the maturity.

I don't know, Bill, if you have anything else?

MR. STRAWBRIDGE: But you do have your chart coming up on the next page which talks a little bit more about Canada.

MR. SIKKEL: Yes, I'll show you a little more detail.

MR. HEDERMAN: We don't have to get hung up on it right now.

MR. SIKKEL: Hold that thought for just a second and we'll see if that helps.

A different kind of plot to the right shows the coal bed methane recoveries. These are different in that they actually -- production increases with time as they dewater and then begin to decline.

It shows different vintages, different timeframes. And the early stuff with the higher recoveries was the San Juan drilling. Over time we see lower and lower recoveries as people pursue lower quality kinds of opportunities.

Some of the more recent stuff in the Powder River Basin -- again it's just reflective of the kind of opportunities that are there.

As Bill was suggesting I had on this next slide a few more examples.

(Slide.)

MR. SIKKEL: We show the Anadarko Basin to the left here and as well we show the initial rates. Those are the blue lines. And the initial decline is in green. And how the initial decline is increasing. But as well for some time the initial rates have been increasing with improved completion technology and crack technology and so on. But even those have fallen off over time.

When you look at the Canadian figures, really none of the indicating figures are that strong. The initial decline rates have continued to increase, as well as the initial rates falling off.

So, you know, the specifics of why that's happening in Canada I can't comment further on. But you see it in all the indicators in the western Canadian basin.

That's really all I wanted to say about those areas we have in our report. And I'll report a lot of additional examples of this type of analysis. We used it to try to get a handle on how we project and go forward.

(Slide.)

MR. SIKKEL: Related to that we also looked at these decline trends of existing production. If you look at that plot on the left, the beige represents the decline from 1990 if you did no additional drilling. If you just stopped drilling over a decade ago, that's the kind of production outlook we would see.

Obviously with each year's drilling activity you get some additional production but then also begins to decline. But what you see in those wedges is that that decline rate is increasing and that is what's reflected in the plot at the right.

So when we say we have to run harder to stay even, this is part of what we're talking about. If there's that much more drilling or improved performance to keep things flat, that continues to be a struggle.

(Slide.)

MR. SIKKEL: This final slide in this production performance area just looked at the question of the response to the doubling and the rate count in the 2000/2001 timeframe, where we saw a little bump in our production rate.

Despite the doubling of the recount that's reflected in that upper left plot, and if you look at the bottom plots, we analyzed where the incremental drilling occurred. And it was really in the places you'd expect relatively lower recoveries -- Powder River, Mid-Continent and Rockies.

And then to the right of that, what each well made in that first year, we were able to pretty well come to the kind of production response that we saw. When we see where that increased drilling is occurring, it won't be surprising that we won't be getting any kind of massive production response to that rate count increase.

It's just another calibration relative to what we might expect from an increasing rate count. And obviously we expect a response, but we don't expect too much of a response.

CHAIRMAN WOOD: Why are those Gulf wells so much more productive in the first year?

MR. SIKKEL: Different rocks. Basically it's much more permeable rock. You expect them to be high, relatively short life.

The rock use in some of these other areas are total rock, lower initial rates, but much longer life. It's just a different kind of producing characteristic.

MR. PINKSTON: On the incremental drilling recently why is so little focused on the Gulf of Mexico?

MR. SIKKEL: You may get different answers, but it's largely opportunities. There's been a lot of things drilled up on the shelf. There's a lot of discussion about the potential of a deep shelf. Some of that is built into our modeling.

From there you go into much deeper water, where you've got much more challenging activities. Where people can find this high-rate, highly productive type of opportunities, they've pursued it.

I think part of what you're seeing is, even at these prices there's less left to pursue. And as well there are areas like the eastern gulf and the Atlantic and the Pacific where they don't have access to go pursue those kind of opportunities.

But you see very limited drilling activities in those kind of areas during this timeframe.

MR. CUPINA: Mr. Sikkel, is it fair to say that even as the technology has improved and the drilling activity, and therefore you'd expect better results and more production?

On the other hand what's offset that is the resource base has declined so much that there's a net decrease?

MR. SIKKEL: The resource base is just very mature. The Gulf of Mexico shelf has been on a very significant decline. We expect that to continue even despite these technology advances. Technology is a big help. I'll talk about that in a few more minutes.

But in some areas we just don't see it allowing you to stay even. That's why the Gulf of Mexico as a whole will stay relatively flat. But there will be the deep water compensating for the declines on the shelf, okay?

(Slide.)

MR. SIKKEL: And this next section gets to costs. I won't spend a lot of time on this.

(Slide.)

MR. SIKKEL: But again, a lot of what this is about is the costs of the supplies, which are important -- that real attention is paid to this.

We used public and commercial data bases. We used real data: API, Jordan Association data. We used M&S data for the Gulf of Mexico. We used Petroleum Services Association in Canada. We used good facilities data.

Then we benchmarked that with industry and said, okay, this is our assessment of what this should cost in this water bed for this depth of drilling and so forth. How does this compare to your experience? Give us some feedback and so use that to calibrate these numbers.

We found that the cost information compare pretty well to the '99 study. We did find that our costs were higher for drilling for deeper reservoirs and put more granularity in the model.

Relating to drilling those deeper reservoirs, one other thing probably worth mentioning is we assume lower rig attrition than the '99 study assumed. The '99 study had fairly aggressive assumptions about how fast rigs would be retired.

In this kind of forward outlook from the price projection perspective we just assumed and our drilling colleagues confirmed that there would be very few rigs that would be down. They'd all be working. We'd keep them busy and so we spend money to maintain them, but we don't have to build as many new ones.

Then just a few examples of that kind of granularity. This shows the Gulf of Mexico drilling cost work. It shows you different water depths, different plays, different drilling depths. And it was this kind of granularity we were able to include in the model to try to include in the model to try to assess what the production response would be.

And you'll see how it compares to the '99 study. So where we could, we tried to make improvements on the granularity of the modeling work.

(Slide.)

MR. SIKKEL: Similarly, for just some other examples we show the south Texas gas well costs by drilling depths and comparisons to the '99 work as well as the people involved and the higher costs associated with the deeper drilling. We have this kind of granularity for all the basins from four to five depth tranches kind of thing. So it's a pretty full sum of model from the data perspective.

(Slide.)

MR. SIKKEL: So we take peace and we couple that with work on what technologies do.

(Slide.)

As I mentioned, Chevron, Texaco led this subgroup to look at how new technologies would impact supplies. We had six workshops with industry experts to gather their insights in the area. Soon they developed technology improvement parameters for the model input.
I'll show you those in a minute.

Importantly, gas production is -- in 2025 -- is 14 percent higher than it would be without these technology advancements. Different people react differently than that.

Some think that's a lot. Some think that's a little.

Personally I think that's quite a bit -- 14 percent. Without the technology improvements we would have 14 percent lower projection of production in 2025. I'll show you a couple of sensitivities around that.

(Slide.)

MR. SIKKEL: This matrix shows you the kinds of technology areas where we were able to make adjustments for the different cases, the reactive path and then some high technology and low technology cases.

CHAIRMAN WOOD: What is the difference there? Just embracing more of what you found. Reactive would assume no new technology?

MR. SIKKEL: No, reactive assumes the technology improvements shown. The high and low basically assumed either more success in applying technology or correspondingly less. I'm trying to think if there were any principles that really drove that. Anything in particular, Bill?

MR. STRAWBRIDGE: No judgment.

MR. SIKKEL: Just judgments about, well, if you try to put a range around how much this would advance, what would it be?

I will say the group tended to see technology improvement as more incremental in nature than breakthrough in nature. And of course it would have been difficult for us to forecast a breakthrough when that might occur -- how you might model that. So it's probably just as well we did it that way.

Fundamentally the conclusions of all this though is that technology is an important factor. It's been an important factor in the past and continues to be an important factor in the future.

MR. WRIGHT: Just hold it for one second. I was looking at the drilling costs. On the reactive path, does that mean the drilling cost is actually going down?

MR. SIKKEL: That's right.

MR. WRIGHT: On the reactive path drilling costs decline more than under high advancement and low advancement?

MR. SIKKEL: Yes, and there are some subtleties to that. I think in that case if you look at the recoveries per well, you see how much higher they are.

In the high advancement case I think they attach some costs to that in that high advancement case that helps to offset some of the advancement in the drilling cost categories. So some of these buckets influence one another as they made assumptions.

MS. STRAWBRIDGE: That's correct.

MR. SIKKEL: So yes, it's not necessarily linear or anything like that. It was in the judgment of the group. And they had, you know, a diverse group -- large companies, small companies, service companies, and so forth -- providing advice in this area.

They didn't come up with any silver bullets relative to how you capture the historic contribution of technology to our business. They talked about that a long time. But I don't have any wisdom to give you about that.

MR. HEDERMAN: In terms of how you end up on the rapid technology advance path or the reactive path et cetera, were there any findings related to who would be funding the technology development or what the different funding levels might be?

MR. SIKKEL: We didn't make any different changes and assumptions on the reactive path or balanced future relative to technology. We did comment on the fact that the federal government's share of funding for oil and gas research is relatively low relative to other areas.

But the group didn't really see themselves in a position to judge the appropriateness of that. They did suggest that DOE look at that and consider whether that is appropriate. Given this environment, whether maybe some additional research in the gas area is appropriate.

MR. HARVEY: You also just indicated a minute or two ago that you had costs by each basin. Did you have technological factors by each basin as well? Or were these --

MR. SIKKEL: We had them by different timeframes. I think we were trying to tailor them to the kind of advances that would be needed in the significant basins, but I don't know that we really applied them on a basin-to-basin basis, did we?

MR. STRAWBRIDGE: We had the capabilities for each one of our producing basins to use unique technology factors. Particularly the Gulf of Mexico would be very different than an on-shore environment. So we had that. As Mark said, we had the technology factors applied over different time horizons as well.

MR. HARVEY: So you did, as you developed these factors, use different drilling technologies?

MR. STRAWBRIDGE: Yes, the Rocky Mountains will be different than the Gulf coast, which is different than offshore.

(Slide.)

MR. SIKKEL: This next slide just shows what I've already summarized. It shows the effect on the production of -- with the high case and the lower case. And in fact with a no-advancement, where we just take out the technology effects altogether.

And obviously you can see it's significant then as well the effects on the Henry Hub gas price versus the reactive path case or the high and low technology case. So just to give you a sense for the impact that it has we did do some comparison of risks with the EIA work.

I'll talk more about EIA forecasts in a minute, but generally our technology parameters were pretty similar. I think the one area we had some difference was EIA assumed more improvement in exploration success over time than we assumed. Our folks were a bit less optimistic.

So you take the resource. You take the cost, the technology, the price projection. And it leads us to commercial resources and production outlook.

(Slide.)

MR. SIKKEL: That's really the next section. This is a bit of a summary of the modeling methodology. We've already talked about it a bit, but basically we're developing the cost and supply for each region using the data we've already pulled together.

The model pulls together the lowest cost supplies until that demand is met and determines the equilibrium of the resulting price, the price as established by that last increment of supply.

In the modeling work we did, the Arctic gas and LNG components were fixed components of these model runs as opposed to something that would vary. So --

CHAIRMAN WOOD: What is fixed? The volumes and the costs?

MR. SIKKEL: They were fixed in terms of volume so they were exogenous inputs to the models. And you'd have to go back and look and say does this make sense to the price projection that we had and so forth.

John will talk about it more. But fundamentally the LNG group determined what they thought would be reasonable or possible may be in this kind of price environment from an LNG perspective.

And that's what we put in because it wasn't sufficient to meet the demand of that price projection. The model had to continue to look to these traditional producing basins for additional supplies and that's part of why you get the kind of price projections you do.

CHAIRMAN WOOD: What about the areas where you've got -- or it's not all for basins or you've got no reserves there. But it's much more speculative. How much of those kinds of numbers are at the core on the supply here?

Which are the new fields on which you don't really have any indication from earlier data or any kind of sub-surface knowledge?

MR. SIKKEL: I'll show you the wedge that comes from new discoveries in just a minute.

CHAIRMAN WOOD: All right.

MR. HEDERMAN: Is this model kind of the latest version of the hydrocarbons model?

MR. SIKKEL: Yes, it's the EEA model that was used in the '92 and '99 study.

MR. HEDERMAN: Thanks.

(Slide.)

MR. SIKKEL: This slide just takes that technical resource here for the lower 48 and calibrates it relative to how much it gets commercialized. It shows how much is commercialized at different price levels and it in essence creates a bit of a cost to supply curve. I'll show you a little bit more on that in a minute.

But basically at $4.00 about 760 Tcf gets commercialized, about 60 percent of this technical resource. Remember, that gets produced over a very long time. Don't think of that as kind of an instantaneous volume that's available to you.

But also the thing to note in the wedges in that plot is obviously the -- is essentially all commercialized at any price. Then the higher cost components, the new field and the nonconventional. You see more and more of those wedges as you go up in price.

That all tends to make sense relative to what the model is illustrating.

(Slide.)

MR. SIKKEL: These next two curves just show some of the granularity we have in terms of those kinds of cost to supply curves by different region and by different resource types. It provides some ability to compare.

This is some of the first data like this that I think is available and people can make their own judgments about. Does this look real? You know, one versus the other?

I think some indications from it were certainly appropriate relative to growth on the right, being a relatively lower cost source of supply than the other supply sources. So it's just the kind of information that would be available when all the output is out there that people can use to build their own judgments about it.

Again it just shows that amount of resource commercialized at various price levels.

CHAIRMAN WOOD: By growth you mean the secondary recovery type issues.

MR. SIKKEL: That could be a source of growth or extensions to existing reservoirs or drilling additional fields. You know history would say that, you know, fields grow well beyond their additional assessment when first discovered. We just get smarter about how to develop them. And we would expect that phenomenon to continue.

CHAIRMAN WOOD: Why is mid-continent kind of out of the track there?

MR. SIKKEL: Just less resource being accessed today than in the past. I don't have the mid-continent-specific slides in here, but they are available for all the basins if you'd like to see them. And they will be in the report.

CHAIRMAN WOOD: In the eastern interior.

MR. SIKKEL: Appalachia. There's a lot of resource there. It's just a question of how much will be accessed and newly developed in this price environment.

MR. LANGDON: It's primarily defined in the -- too, right?

MR. SIKKEL: Right.

MR. CUPINA: These seem to indicate the higher the prices, the greater the supply, and that's expected. But at the same time, right now we have historically high prices, yet we started off talking about declines. So where's the mismatch?

MR. SIKKEL: I don't know that there's a mismatch. It's just that each increment is a bit more marginal and a bit smaller than the increment before so that the first 50 cents of a price growth doesn't necessarily give the same response as the next 50 cents. That's what these curves reflect, that bend over in time.

Eventually you reach a point that some of those resources are not commercial kind of regardless.

MR. HEDERMAN: Looking back at page 13, probably the biggest difference I see between the '99 and this study is the drop in the reserves growth. Is it all just the rapid decline rate in the drilling? Is that the primary explanation?

MR. SIKKEL: It's really the work we did on recoveries per well. Based on the analysis of the well -- basin, I'll show you a little reconciliation to the '99 work and to the EEA work. There were also some differences versus the '99 study and the technology assumptions. We're a bit less optimistic than they were in '99. But that and the recoveries per well and the resource base were the three key ones.

(Slide.)

Just to continue on because I want to leave plenty of time for everybody else. This just shows those projections with a little more granularity than we saw earlier.

Obviously the mature region is declining and the growth from the deep water, Gulf, and nonconventional areas. Also nonconventional production is growing as a share of overall production, which I think is unexpected. But this outlook would say it would be 40 percent of what we produced in these traditional areas in 2025. That's a significant component.

(Slide.)

MR. SIKKEL: To the question earlier of, well, what share of that future production comes from different areas, this upper left plot has drawn a lot of interest.

But it just shows if you take the proved reserves today and let it decline as we expect it will, then you add in the wedge for growth of those proved reserves, you get a big wedge of additional undiscovered reserves that has to be found and produced, some of that conventional and some of that nonconventional.

I hope that gets to the earlier question about how much comes from these other areas. This is what we've been doing in time.

It's just that obviously the proved wedge is declining faster than it used to do, so it makes the task that much more difficult than to the right you just see some plots we did relative to the expectations for production over 48 and at some different price levels with production declining and a more historic kind of $3.00 price range. That's why we get the outlook we did.

(Slide.)

MR. SIKKEL: Just to close out this section, a few comments about activity levels. We do see growth in activity from, say, the last decade, but not from recent history. So we think this kind of outlook is do-able in terms of the drilling requirements. The same is true of the capital requirements both for exploration and production.

(Slide.)

MR. SIKKEL: Then, finally, this last chart. And I won't spend a lot of time on it, but it talked about some of these earlier projections.

In the upper left you can see that our outlook, even at a higher price projection, is lower than the '99 NPC or the 2003 EIA outlook. We've already talked about the '99 study at the lower left. But if you look to the right versus the EIA outlook our offshore outlooks are very similar.

The EIA is much higher than this outlook than the onshore. And the reason they are shown at the top, the higher the resource base, the higher nonconventional recovery is in a different activity mix.

We've been sharing some of our information with the EIA as they put together their current outlook. That's a lot of kind of the traditional areas.

I had a lot of good questions. If I can, I'm going to move on to access now for a minute -- and try to keep moving.

(Slide.)

MR. SIKKEL: I'm going to go through this pretty fast. I think you're familiar with the issues here. But we wanted to take a hard look at this area and the complexities of the regulatory and environmental outlook and really quantify the impact and recommend actions that could be taken to support develop.

We wanted to expand on the '99 study work, go beyond lease stipulations to conditions for improvement. We compiled habitat maps for the major basins. We estimated the cost and timing impacts of the regulatory process. We tried to quantify that statistically and recommended improvements.

(Slide.)

This complicated flow chart is the process we went through developing the maps, calculating the percentage of each basis impacted by different habitats, trying to quantify the requirements associated with these habitats, and going through basically a simulation process to assess, well, what does that mean relative to access to resources and the costs and delays associated with meetings those requirements.

(Slide.)

MR. SIKKEL: I just put in a couple examples of the kind of habitat maps we developed. We used an environmental consultant to put these together. One shows the big ranges. I think we have 50 or 60 of these kind of maps for various basins.

Another shows some of the grizzly bear and other areas that have less impact on this particular basin, the Green River. There are some of these maps where raptors or other species -- you know, the entire map is covered. It's an area that is impacted in its entirety by that species.

(Slide.)

MR. SIKKEL: We put together quite a detailed analysis matrix with 50-some line items for each basin as to okay. You need to deal with a certain issue in a certain area. What kind of activities do you pursue? What's the probability of that happening? How much time does that take? What are the costs associated with it?

Not in any way to suggest that those activities aren't appropriate, but looking for ways to streamline the process, improve your ability to kind of get the window you need to do the work you need to do without any detrimental environmental effects.

CHAIRMAN WOOD: How many basins were reviewed in this manner?

MR. SIKKEL: Four. They are shown in this next slide. Green River, Uintah, Powder River, and San Juan. We show that leasing percentage that comes out of the EPCA study work by the Department of the Interior and assessment that this really impacts a broad area associated with the facts that requirements are often such that you are essentially closed out during the course of the year from getting into certain areas even though they should be accessible.

And there are costs associated with that as well as time delays. Then what we did was --

(Slide.)

MR. SIKKEL: -- given those effects, if you could improve your access and your streamlining of these processes 50 percent over 5 years, which is a pretty modest kind of improvement I think, 10 percent per year, and you couple that with lifting the OCS moratorium at the beginning of 2005, what kind of effect do you get?

And we show the price and the effect related to that as well as the reduced access case, that says basically the trend continues. And we see access to less and less resources over a 10-year period.

The map just shows the amount of resource that is either off limits to the moratorium or that is off limits associated with our conditions of approval.

MR. PINKSTON: What was the basis for the resource projection on either coast? Has there been enough exploration work?

MR. SIKKEL: It was really the available information from the MMS. There was not a lot of new data.

We had to update that from prior assessments. I thought the folks made a few adjustments, but the numbers are not all that different.

And then, just to keep moving, we made a number of recommendations in the access area.

(Slide.)

MR. SIKKEL: I won't go through these, but they are all around: streamlining processes, improving processes to insure the time it takes it takes to go through the appropriate processes can be minimized.

(Slide.)

MR. SIKKEL: And then similarly the OCS recommendation to pursue a phased lifting of the moratoria to try to get access to key gas-bearing basins.

(Slide.)

MR. SIKKEL: A final section before I turn it over to John. Two comments about the Arctic work.

(Slide.)

MR. SIKKEL: As I indicated, this work was co-led by the Prudhoe Bay resource holders. Basically the assumption was that the frameworks were achieved and the conditions would support these projects coming forward in the timeframe of the study.

We had MacKenzie starting up in 2009 at a Bcf per day, expanding to one and a half in 2015, in Alaska starting up in 2013 at total capacity the following year. We did look at some sensitivity cases around it. And nonetheless the pipeline case increased average prices by about 8 percent in that timeframe.

(Slide.)

MR. SIKKEL: Our recommendations here are pretty straightforward and I hope the enabling legislation will be passed this year and then some other recommendations are Alaskan fiscal certainty.

CHAIRMAN WOOD: I know we're going to get to the demand side later, but does that slug coming from the north -- I assume that some of it gets diverted to the oil sand production.

MR. SIKKEL: It does, and there's a lot of uncertainty as to just how much will come south. But we did look at what the oil sands consumption would be. You have to couple that with the declines in production in western Canada overall. And then MacKenzie gas coming first. So all that is part of the mix.

(Slide.)

MR. SIKKEL: One last comment just about documentation. I have covered a lot pretty fast, but I want to assure you that there will be a lot of transparency and depth to what you see about our work, the resource-based work, this production performance analysis, the cost estimating work. That information will be available soon.

Also we think there's some benefit from future efforts to try to standardize some of the assessment methodologies from collaborative work with EIA on some of their outlooks and so forth.

Then as well we'll leave behind some modelling capability that can be used by others to continue to serve these issues. So a lot of good documentation. With that I'm going to turn it over to John to cover the LNG piece. I have left him three minutes.

MR. HEDERMAN: One quick question. You mentioned the one model earlier. What's the second model that you are talking about there?

MR. SIKKEL: We also did some work with the Altos model outfit in California.

MR. HEDERMAN: Didn't that used to be called NARG?

MR. SIKKEL: Yes.

MR. HRITCKO: Thank you.

(Slide.)

MR. HRITCKO: Good morning. What I wanted to do today is take one piece of the MPC study while it's gotten a great deal of attention here, particularly over the past year, that being LNG.

As with all the subgroups -- I think Rich Kinder remarked earlier this whole study is replete with many experts in the field in the LNG subgroup. This is no exception. We have representatives from all aspects of the business from the LNG supply side, terminal operators, the pipeline representatives. We have consultants representing LDC interests.

We had a good mix of overall input into the discussion. Throughout the year we started this process approximately a little over a year ago. We lamented the fact as we progressed through our studies that there was report after report and study after study that kept coming out talking about LNG and in essence stealing our thunder.

However, I think the value of the recommendations that you are going to hear today, while they won't be appreciably different from what you may have heard, in many other forms throughout the industry I think it's good to have a validation of those results from some of the leading experts and participants in the field.

(Slide.)

The objective of our subgroup, as pointed out here, was made fairly specific in our request from the NPC: that being to assess the cost of LNG in the value chain. In order to do that, we have to look at all parts of the chain, from supply, transportation, regasification, evaluate the competitive global market, prices for not only supply but also the shipping and assess to the extent we could global markets and, in particular, we used this input into the modeling efforts done in the North American models for our own market studies. We identified controlling assumptions that would affect the pace of the growth of LNG. This is a complex process and doesn't come on instantaneously and there's numerous factors that have to be considered, particularly when you look throughout the chain.

So we did that as a group, broke down the chain and looked at all the individual pieces and tried to determine exactly which factors were critical in development of this LNG supply. We developed three cases for the modeling and, as Mark had indicated before, the LNG piece is exogenous to the model; in other words, the model doesn't generate the numbers that we had here today. We actually came up with an analysis of the supply, the shipping, the regas capacity, and came up with a determination of prices, a range of prices from various parts of the world to U.S.

markets and then looked at the probabilities or the potentials of this LNG coming into being into the U.S. market.

We came up with what amounts to, in the model, a reactive path, a balanced future and then a load sensitivity, which we'll discuss further in these slides. We formed recommendations, which I want to spend the most time on at the end of this discussion, and also developed an LNG primer, which will be available later on this year which will go into much more detail about all of those aspects throughout this whole process. While we had parties that were participating throughout the world and the U.S. in the LNG business, we had to key off of publicly-available data that would be generally available in order to tie in -- so all our information is based on information that can be accessed and verified from public sources.

(Slide.)

When you look at the LNG portfolio, you have to look at the full value chain. We often term the LNG as the LNG chain. You have to look at the characteristics of each of those; it starts with the production, goes through the liquefaction process upstream, you have to look at shipping to move the product from the supply area to the market area and then also regas -- our group looked through to the regas' abilities themselves. Then we had interaction and interface with the T&D group, which we'll discuss later on the implication of having these terminals sited at various locations and what the impacts would be on the downstream pipes and the market.

But to say the least LNG is a business that, to be economic, requires economy of scale to be captured. You're looking at very significant reserves for any particular supply project, looking at 7-10 TCF, investments of $2- to $5 billion that could even be argued to be on the low side. There are projects out there today, just to access supply themselves; companies are investing $5 billion-plus for supply alone. Volumes are large; you're talking about half a BCF to well over a BCF in one of these projects. This necessitates a long-term market structure in order to develop these projects initially, although we are seeing the development in the market place of spot trades or short-term trades that are being used to provide more efficient fillers for various times during the life of these projects. We can counter some of that.

However, what we're looking at here throughout the study are the long-term supply projects which would in fact underlie a growth of regas capacity in the U.S. There was no assumption made and no argument presented that would say that LNG regas capacity would be built on spec and based on spot, so we have to look to the long-term market.

The timing of these facilities that we had included in our assumptions, particularly for the regas development -- when you look at developing a terminal, you have to spend at least one year in preliminary development, often more, to become successful on a project. We assumed a two-year permitting process for a project, that includes everything from Federal to state and local permits in order to construct the facility and then the design, engineering and actual construction of the facility takes approximately three years. We had those assumptions embedded in the development of our supply.

MR. WRIGHT: Excuse me for just a minute. Your timing of two years for permitting doesn't quite jibe with the recommendation that we have one year for LNG permitting that was mentioned earlier. That's the wish, isn't it?

MR. HRITCKO: That's the recommendation in order to achieve our balanced future case, which is considered our high case. We need to do this in a much more efficient, faster process.

CHAIRMAN WOOD: Is it practical?

MR. HRITCKO: As a practical matter, with the model assumptions as they exist today, we assume a two-year process.

Also, a balanced future, we did assume a quicker turnaround on those models. So in our high case we are assuming that these regas projects are in fact being delivered at a much faster rate.

(Slide.)

The next slide gets to a quick overview of the worldwide reserves. I think it goes without saying that the natural gas reserves throughout the world are vast. We certainly aren't, as a global economy, running out of gas supply. You see figures here pointing to something around the order to 6300 TCF of reserve worldwide with regard the LNG supply, there is an existing supply. It is growing. Projects are being announced each year in new areas going out to develop either expansions of existing projects or new projects. We have long-term supply outlook for LNG being quite robust. So we don't see a problem with the worldwide supply of LNG.

(Slide.)

The next slide sort of colors in some of the details behind this. We give you some history of the LNG business since its inception in the early 1960s and where some of this LNG is going. Obviously, the bulk of that, everyone is aware, is sold into the Asian markets: Japan, Korea, Taiwan, China is now becoming -- they're working on terminal development to become an increasing importer of LNG. But we also have European countries. We have from the early days four existing terminals in the U.S. during this period of time that we see here. We dwindled to a very small volume; we are increasing that. And this goes to our projection of the future.

We see a market worldwide that's growing at a 6-10% rate per year, which can double by the year 2020 or 2025. So we see a very strong supply picture worldwide.

(Slide.)

Our group looked at supplies, once we got our hands around global supplies that are available, we have to look at supplies. Not all supplies are equally suitable for delivery into any North American market. So we ended up breaking down the world into essentially three trenches of supply: the Atlantic Basin, Middle East, and Pacific. We see the numbers that we have here -- quite large supplies, these are, in fact, low numbers today given the fact that many of these numbers were developed six months and pushing a year ago. So there have been projects announced since then that would even increase these numbers to a larger degree.

We looked also at the cost involved in moving these supplies to the U.S. markets, whether that be in the Atlantic, Gulf Coast or Pacific Coast, adding up everything from the drilling/acquisition of supplies, the liquefaction costs, the shipping costs to the various portions of the United States, then the regas cost. We see here a really broad range of between $2 and $5; however, I'm about to say that a good portion of that supply came in the Gulf of Mexico delivery locations, well within the $3 to $4 range, which worked out in the model as market. It indicated very well the model picked up all the supply that we had available. So we had no problems showing deliveries of this supply into the marketplace at any prices that would not meet the market-clearing price. Also, the last column, the BTU range, which I'll get to a little bit more specifically. There is one issue that we have to come to grips with in certain supply areas: not all supply will be able to be delivered into the U.S. market at existing pipeline quality specs. So we have to consider the quality implications and what impact that may have on the supply availability. The broader our quality assumptions and the broader our capabilities are as an infrastructure and as a business in the U.S. to be able to handle these various supplies, the more diverse our supply base will be.

(Slide.)

Looking at some of the factors, as I said before, we stepped through the total LNG chain, starting off with supply, going through transportation, regasification terminals, and then, to a lesser degree, some of the issues at the front end of how some of these issues impact on the U.S. market. From the supplies, as I've said before, these projects are massive capital projects involving many billions of dollars. You have to consider the geopolitical considerations and construction timing of those projects, all of which have to be coordinated right down through the chain, with the shipping, with the regas project, to the marketplace. It makes for quite a complex chain of events that must be handled both from a project standpoint and also a commercial standpoint, including a large number of very large project sponsors that have to have their various objectives met throughout the chain. So it is quite an undertaking to develop these projects.

Shipping: There is an existing fleet of slightly over a hundred tankers available today. We're looking to have something on the order of about 146 LNG carriers by the end of this year, depending on where you're counting from. There are various backorders of ships that are available. Most of these are being dedicated to the various projects. However, as I said before, the timing throughout the various parts of the chain often are such that a tanker may be delivered a year or so in advance. It is employed through time charters on shorter term or spot charters, as well as to be used until the long-term shipping.

But we looked at all the aspects of the shipping and concluded that, with the number of suppliers that are out there available to manufacture these ships, even considering the backorders and the quality of the tankers that are coming off, we did not see a long-term project. You may have short-term displacements in terms of one supply project comes on and one tanker may be available for short-term; our overview was that the shipping would generally in the long run meet the demand requirements and would be built with the supply projects.

Regasification terminals, of course, we have a myriad of issues that project sponsors are grappling with in the U.S. today in terms of siting these facilities. Location is the key. Access to deep-water ports and, too, sufficient infrastructure on shore to be able to move these large volumes to market. We have various new technologies that are being explored: offshore gravity-based floating projects, direct regas, are all being proposed in addition to the traditional on-shore facilities. All have special requirements.

Public opposition and the permitting are two of the key areas, and the bulk of our recommendations that I'll discuss go to some of those issues. We know the public is very much concerned about LNG. A lot of this stems from just lack of knowledge of what the product is. A lot of misinformation. So there's a lot of work that needs to be done to educate people that will, in fact, get to a lot of the issues involving timing of these projects that a more educated marketplace will in fact embrace the notion of having LNG new gas terminals built much more quickly than those who are concerned about it.

Pipeline interconnections. As I said, the T&D group will talk about those more in advance. But we also have to be concerned with the LNG interchangeability issue, which in fact speaks to the supply portion.

MR. HEDERMAN: I'm sorry; I'll give you a quick question on the offshore option. Are there any offshore regasification facilities in operation anywhere today and what's the cost impact of doing that rather than conventional onshore?

MR. HRITCKO: There are no offshore regasification facilities in operation as yet. Of course, we do know that Chevron/Texaco has a facility being certificated right now within the deep water port offshore Gulf of Mexico. I don't believe that will be the last cost coming in. It should be comparable to facilities that would be onshore, and that's the reason many sponsors are beginning to look more seriously at these alternatives. But it is a new technology and it is something that, while it's a new technology, it's an application of existing technologies in a new fashion.

(Slide.)

The next slide gets to the bottom line of our study. It shows overall the terminals we have projected. The blue first is sort of as a base. We see the four existing terminals in the U.S. and we have red dots indicating in the various locations around the coast.

We also included two terminals in Mexico: Alta Mira and Baja. The group had assumed at least one terminal in Baja would be built. We see five U.S. terminals and two Mexican terminals in the reactive path, that increasing to seven terminals, along with the two terminals in Mexico under the balanced future, and we see the build-up here considering all these various aspects. We went through and, of course, the assumption was that the existing terminals would be reactivated and expanded first, then the new terminals would be added to that.

Under our reactive path, we end up in 2025 with a total of about 12.25 BCF a day of import capacity. That increases to 15 BCF a day under the balanced future.

(Slide.)

The next slide actually provides some volumetric data that goes behind some of the geographic information as to where these terminals and how the buildup would come about. And it shows that ultimate buildup up to 2025.

I think the key points that I'd like to make on this particular graph are that all three scenarios are common, at least through the latter part of this decade, and that gets to the point that the primary activities will be on the existing terminals and it takes a number of years for the projects that are on the drawing boards or in the permitting process to come on-stream later on in this decade.

Beyond that we see the various assumptions as to the development of these volumes. I think basically what we're seeing here is that our supply will support the development of these terminals and that the factors that do control will have an effect on how much -- there won't be an infinite amount of LNG being brought in, as some people have been concerned about, that it will overtake conventional production. These graphs certainly get to the fact that while this will be an important aspect of filling the gap in our future needs, it does in fact illustrate that there are limitations on the amount of LNG that will be brought in.

MR. WRIGHT: John, I just had a real quick question as I read the graph two slides ago where the balanced and the reactive cases were added in. I thought they were exclusive in terms of --

MR. HRITCKO: The projects themselves are additive. You can, in fact, look under the assumptions of the reactive path you have ultimately ending up with 12.25 BCF a day total. The balanced future, however, adds to that two additional terminals. That is additive. We did see a marked difference. If you have an increased number of terminals or a decrease in the amount of time for permitting and broader acceptance of LNG to markedly change --

MR. WRIGHT: As I was reading the report, I thought it said that the balance -- you would only need two new LNG because --

MR. SIKKEL: The import is actually higher in the balance case than the reactive case.

MR. KINDER: This shows even in the reactive case you have huge need for LNG, as you can see. That's an enormous increase to be talking about, 12 BCF a day, a market for LNG, even out that far. And the balance future case -- which is obviously what we've strongly recommended, which would also embrace speeded-up permitting -- gets you to that higher number.

(Slide.)

MR. HRITCKO: This next slide shows some of the pricing sensitivities that will run as part of the overall study.

(Slide.)

You can see that under the balanced future, which is the high case with LNG -- of course, these prices also reflect the Artic gas and some of the other gas coming on -- you'll see the price impact is quite dramatic. Where we have decreases in the future projected price versus on our low sensitivity case where we only have two additional terminals built, we actually see a sizable increase in the price of gas assuming these market conditions in the LNG supply is not made available. So there is a price implication for not having the regas capacity of this LNG brought into the marketplace.

(Slide.)

My final slide gets us to the recommendations which I'd like to point out, sort of the meat of the discussion here today. As we discussed, we'd like to see the permit process for new regas capacity reduced to a one-year period so that we can do that by bringing in streamlining, and by that I mean more coordination of the various agencies both within the Federal, state and local agencies that are all needing to meet specific requirements.

We're not talking about excluding any particular permitting processes, just doing this in a more efficient manner, coordinating the acquisition of data, the use of data among the various agencies. I think some of the activities that have already gone on among Federal agencies with MOUs among various agencies and departments has moved us in that direction.

I think it's especially critical that our team has identified a great number of areas in the environmental permitting process which forms the bulk of much of what goes into these applications that can be shared throughout various agencies at all levels of government. We could use that as ways of streamlining and improving our processes.

Also funding and staffing of agencies was a critical area. With regard to FERC, FERC has been the traditional reviewer and continues to be the reviewer of onshore facilities and you have embedded staff and people with a skill set that understand the process. However, there are agencies under the Deep Water Port Act who are coming up on the learning curve fairly rapidly. They have a number of other activities that they have to coordinate as well. In order to process the number of applications that we think will hit the regulators, additional emphasis has to be placed and resources properly placed in the various agencies and departments to adequately review these.

But then even beyond the permitting stage there will also be a need for additional manpower and staffing for just the sheer day-to-day handling of the cargoes coming into the U.S. That will be anywhere from additional Coast Guard personnel to inspect the tankers as they come in, to people handling the paperwork at the dock and loading facilities with this increased activity that hasn't been seen in the history of the U.S. energy market. So there's a lot of areas that need to be focused on within the government that need the appropriate resources.

Undertaking public education, as I said before, that is a key area because as we see it the public has some knowledge of LNG but many times, while they may not come out in opposition to LNG, we find that they just don't know enough about it and are skeptical of the claims made by the sponsors and industry. We think that will in turn, if we can educate them and bring them up to speed on the industry, and that includes activities here within this Commission -- as I said before, which is uniquely positioned because of its history in LNG -- we think there are avenues there to educate the public that can be developed.

Update natural gas interchangeability standards. Here what I'm talking about are the supply characteristics. Interchangeability in the most basic sense: the ability to substitute one gas for another without seeing any appreciable change in the burner performance or safety of the product. As you refer back to that slide, throughout the world we see that LNG is used effectively in many market areas there. It is in fact interchangeable in most markets. Our system has been designed and developed primarily attuned to our own supplies developed domestically, particularly in the Gulf of Mexico. Typically, a lower BTU because of processing in the Gulf.

However, that isn't the key element in interchangeability. Interchangeability, as I said, gets to the burner characteristic and it gets to safety, incomplete combustion formation of carbon monoxide in residential appliances, it gets to power generator processes in turbines, it gets to processed gas users who use this product who may experience differences because of the slightly different gas supply. It also gets to basic measurement and control where you have slightly different chemical compositions and higher BTU of gas that have to be accounted for so they can be properly measured and billed to the marketplace.

There's a broad range of activities under this rubric of interchangeability that goes beyond just the BTU. We believe, and we've seen, it starts actually going into the interstate grid. While interchangeability is traditionally thought of as a local distribution company issue, it actually begins at the interstate pipeline. There are activities that have to be looked at, there may be adjustments that need to be made going forward to the pipeline system in order to make the gas -- allow this gas to be brought in. However, these aren't insurmountable and they aren't overly expensive. I can speak from my personal experience or I know the experience of some of the folks in our set group who have faced some of these issues already. They're finding that as you approach this issue that the various downstream customers, once they understand what the issue is and they actually look into it, there are in fact many ways in which this issue can be addressed.

So we see this as starting -- as part of a process of all these specifications being included in pipelines so they can't accept this gas but then flowing all the way down to the end use customers and the LDCs. It's an issue that spans the industry but it's something that must be addressed. The bottom line is if it's not addressed, we're limiting ourselves to the amount of supply globally that we can access if we limit ourselves to, say, a 10/50 standard.

MR. PARKER: Can I just add something there from the NPC standpoint? As we got together as a group, we just wanted to make sure as we talk to the Commission today that we aren't focused on one project, one plant, one pipeline, one input point. It's really a national issue. We need to take a step back and look at the distribution companies and the pipelines and the LNGs -- it's a total effort to look at the standards and what's required and what's needed from a safety and reliability standpoint to make sure we can get the supply. So in the study we actually asked, I believe, DOE to do some work in trying to gather all the parties up and analyze what it looks like from a regional perspective. It's more than just a one-point thing.

MR. HEDERMAN: Could you explain, just in your initial thinking, if this is an important incremental supply, it would seem that the solution is there at the regasification plant gate, that this processing is necessary rather than adjust the whole system?

MR. HRITCKO: That would be fine if all you were looking for globally in your supply would be new incremental projects that in fact build that type of infrastructure into the liquefaction process. In other words, remove some of the ethane and heavier hydrocarbons. However, there is a tremendous amount of LNG already available that we can avail ourselves of. We have to look at our quality specs on this side of the chain as well in order to be able to access the LNG that's out there and bring that on immediately.

MR. HEDERMAN: But why not downstream of regasification? I thought you were talking about upstream of liquefaction.

MR. HRITCKO: I may have misunderstood. I thought your question was going to upstream with liquefaction. There are things that can be done; however, those would be for the new projects. There are many projects in place, liquefaction supply projects that don't have that capability right now and would be prohibitively expensive. There's no market for such products if they are moved upstream. In order for us to immediately have access to some of the supply that's out there now, we have to face that from the downstream of the regas.

Also for us, for our market to in fact look more like the global market for natural gas -- and we're finding there is, in fact, no reason for us to have such a narrow range of quality specifications -- in fact, when you look at interchangeability, our system can in fact become a broader spec system that will allow this to be used.

MR. HEDERMAN: Even on combined cycle gas turbine?

MR. HRITCKO: Yes, indications are from our technical experts reviewing this with the independent power producers or large utilities, we find that the interchangeability is not as great an issue for those applications as they are maybe for certain process gas users or even local utilities that may have a peak shaver located on lines.

MR. PARKER: Your question goes to the heart of why we need someone talking to the whole industry, because those are the type of questions that need to be asked: do we need to change our standards or does there need to be more processing? What's driving that? So that's when we talk about working with the LDCs, the industrials and the power plants and the LNG producers, to try to look at that from an overall national standpoint.

MR. HRITCKO: To add to that, when you look at that issue, you'll rapidly find that you have a much better economic situation by looking downstream of the regas rather than taking these products out upstream. It's much more cost-effective to the marketplace.

MR. SOTO: What role do you see this Commission playing in that effort to create a national audience to address these issues?

MR. HRITCKO: As I mentioned before, I see this Commission, with its expertise and background and unique knowledge in LNG and also purview over the interstate pipeline grid being sort of the first line of where the gas supply is going to be entering into the marketplace as being, if not the lead agency, a key lead agency, a key agency in terms of reviewing these supplies.

This is something that is relatively new. It wasn't looked at somewhat during the initial phase as an LNG introduction into the U.S. market back in the Seventies and early-Eighties. However, it hasn't been an issue since then. So now it's at the state -- or at the level of the market that we have to revisit that issue. And we believe that FERC, with its background, is uniquely positioned to be able to assist in that process. We would ultimately see that this would manifest itself in slightly different quality specifications for some of the interstate pipelines that are going to be receiving this LNG as a supply.

MR. CUPINA: I have a question. But first, I'm going to plug our process and point out that the Hackberry Cameron terminal, which is the first new one in 25 years, the Commission dealt with that in 15 months, I believe. We're confident that we can probably meet your one year with our new prefiling process where we bring in all the stakeholders well before filing. So I direct any sponsors' attentions to that.

My question, though: I think two weeks ago we had someone make a presentation on behalf of NGSA. One of the points that was made was that there may not be an assured gas supply for the terminals, at least not in the short term, because of the competition for LNG worldwide. And he pointed out some of the countries and the growing competition. I just wondered if you would address that. I was kind of skeptical about whether that's true.

MR. HRITCKO: You're skeptical about whether there's a competition?

MR. CUPINA: I more or less assume the gas supply is there, the liquid is there. So I was surprised to hear that it might not be there because of competition.

MR. HRITCKO: I think this gets to my comment earlier, the graphs that showed our buildup under the various cases. We did, in fact, have a great deal of discussion and looked into the possibility, because the question was raised, if there is so much natural gas throughout the globe, why aren't we just inundated with LNG?

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The fact is that there are factors that do, in fact, throttle that unbridled volume into the U.S., some of which would be sitings of the terminals, acceptance by the public, permitting process, but also the fact that these are complex commercial processes and, in fact, they are being competed for throughout the world.

The U.S. isn't the only place that has a maturing supply base. If you look at Europe and its traditional North Sea production, which has served the past 20 years, it, in fact, is also experiencing the pains of the years of being developed.

So you have countries that are looking more and more toward LNG for supply and you have competitive markets out there that are able to pay comparable prices. So when the spots are on LNG projects, a liquefaction project looks at the marketplace overall, and they obviously are going to try to get the best price they can, but then also diversify their supply.

You won't see people just going out there developing purely for the North American market and there will be competition for that supply. It won't automatically be assumed that it will come to the U.S.

MR. LANGDON: While we acknowledge how quickly FERC moved on the other terminal, we think there's certain states where it is going to be more difficult to process than in Southern California, for example, which might be a longer process, if you tried to site one there.

Our hope is that a template can be developed where you can meet that one-year standard across the board.

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MR. HRITCKO: Finally, our last recommendation to industry standards should be reviewed and revised, if necessary. We are not proposing any specific changes on the standards, but we believe that it's not accident that there has been so few accidents in this 40-year history of the business.

Standards throughout the world and in the U.S. have shown existing codes and regulations do result in an exemplary safety record. However, it goes without saying that all processes, no matter how good, can benefit from a best-practices review.

Here again, FERC should be in a position, as a reviewer of these projects over the years, and with this unique expertise located within the Commission, we see them as being a key element in terms of reviewing some of these going forward.

I guess, to summarize, our subgroup reviewed all of the activities and assumptions that were asked of us. In the study itself, we found the natural gas is, in fact, plentiful, globally.

The bulk of our supply to meet North America's needs will, in fact, be produced domestically. However, LNG will serve as a key piece of the supply picture, going forward to fill part of that gap.

We have much work ahead of us in order to bring that to fruition, but we think that LNG can be, in fact, a safe, secure, and reliable supply. Those are our findings of the subgroup embedded in this report.

CHAIRMAN WOOD: Going back to the map, on the chart like this, you envision five additional projects to make the reactive case, in addition to the four we have today. I assume one of those would be the Hackberry. I'm just putting names on these dots here.

In the red and white boxes, we've got the two Mexican projects. We've got one offshore of Louisiana. We've got the Hackberry. What would that other one be? The Chemier Project?

MR. HRITCKO: We were careful to not identify any of the particular locations with a particular project.

(Laughter.)

MR. HRITCKO: However, what these points do, in fact, refer to are actually locations within the model that had supply nodes where we were able to most readily be able to put the supply into the model, so that the model would be able to calculate the impact on the market.

CHAIRMAN WOOD: The two yellow boxes would be, I guess, the Long Beach and then Calypso; is that right, Rob? Is that the Florida one, the Calypso one. Is that the name of the one off the Bahamas?

We've already approved the pipeline there and we don't have to do that. That's actually a vaporization project, right? That's in the Bahamas.

We've got that one and the two up here on the East Coast or what?

MR. HRITCKO: Again, those are generic projects.

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CHAIRMAN WOOD: What's out there? Fall River?

MR. HRITCKO: Right, and Weaver's Cove?

CHAIRMAN WOOD: That's one project, right? What else do we have? Those are the only ones. Probably some people come by my office to talk about them and I can't talk about them. So I'm just asking you guys, which ones are these?

MR. CUPINA: The other red dot for the East Coast could be another one south of Massachusetts, but we're also -- some of the spots are trying to keep these close at this point.

CHAIRMAN WOOD: Of all these red dots here, the only two that seem to be kind of non-public items are one of these indeterminate ones on the East Coast and offshore Louisiana. Of course, we aren't dealing with the Louisiana one, so that one maybe is out.

MR. HRITCKO: There is an offshore terminal.

CHAIRMAN WOOD: Even the two yellow ones seem to be largely underway, well beyond the chat stage.

MR. HRITCKO: They are in various stages of commercial discussion, however, the yellow ones, in particular, have not actually gone forward on processing. They are filing applications, although I believe Long Beach has initiated the prefiling process.

Of course, one of the Bahamas projects had its pipeline application approved by this Commission, however, they still have much work ahead of them on the Bahamian side to site the terminal.

MR. KINDER: Again, let me emphasize that it was not the intent of this group to pick specific projects. We just sort of geographically sited --

CHAIRMAN WOOD: I'm just trying to ascertain how realistic it is that we can actually get to the yellow case, and knowing kind of where each of these projects is in the pipe, kind of helps me figure out --

MR. MANNING: Mr. Chairman, if I could just speak to that, briefly? Sommmerset is in the discussion phase. There's a Canadian project with discussions going on in Maine and Sommerset, Massachusetts, Weaver's Cove.

There are multiple discussions going on in the Northeast alone, so --

CHAIRMAN WOOD: Is the one you referred to in Canada, the St. Lawrence one that I heard about last week?

MR. HRITCKO: That's actually a new one that came in.

MR. MANNING: There are two: One in Nova Scotia and one in the St. Lawrence. These are all just in the discussion phase. That's why we avoided that discussion, but the discussions are going on.

CHAIRMAN WOOD: I've got a question from the Committee here. If we get more than these dots, do we get a credit on one?

(Laughter.)

CHAIRMAN WOOD: I'll trade you an LNG terminal for an offshore drilling permit.

MR. PARKER: One thing we looked at, Mr. Chairman, is, if you couldn't get these permitted on the East Coast, what can you get in the Gulf? We talked about that a little bit. It just means that your pipelines are utilized at a higher level.

CHAIRMAN WOOD: We have seen some of these gas quality issues pop up in some of these tariffs that we've dealt with. The one that we just did a couple of weeks ago, came in for trunk line. It was one of the pipes down there. It was much less of a concern. It gets diluted by all the riches and the gas gets diluted from all the rest of the gas flowing up from traditional sources here in the country.

I guess, just thinking out loud, we've got to deal with, if we do have more market areas, LNG injection, we don't have that, duration factor quite as available.

MR. HRITCKO: That's right; that's why it makes it even more imperative that if we are to access certain supplies that our technical folks say, in fact, are usable in the market area, we need to address our quality standards.

MR. PARKER: I think that from the pipeline side, though, the dilution only goes so far. You bring more terminals on and you get more supply coming in, and you're not going to have the ability to blend down to the level you see in these.

CHAIRMAN WOOD: Is the ultimate result of that particular discussion, that you actually have at the retail user level, a richer gas coming out, or that the LDC has an obligation then to get its gas down to -- are the end uses in Japan and France and Italy, are they all at a Level-50 gas at the burner tip?

MR. HRITCKO: Their LNG supply sources are, in fact, much higher Btu upon delivery. However, you have to look at specific markets.

For instance, in Japan, the characteristic of the market is that that gas is being used to generate electricity to serve the market. You don't have gas being used to the extent you have here in the U.S. for space heating purposes.

However, it is acknowledged by the technical experts, I'm told, that the Btu can, in fact, be higher and still be burned in appliances today in the U.S. It's simply the fact that we've traditionally had -- we've tuned our system to a much lower Btu standard and what we have to do is reassess what it is that is impacted by this.

In fact, one of the issues, as you have mentioned before, within the Cove Point situation, was, in fact, that they used nitrogen blending. Prior to acceptance of that, there was extensive testing done on burner appliances by outside consultants that showed that blending this high-Btu gas with nitrogen, in fact, provided a gas that was fully interchangeable with pipeline gas, proving the point that, yes, you will, in fact, have a higher Btu going to the burner tip.

However, you don't have to sacrifice safety or operational considerations at the burner tip.

MR. PETERSON: That interchangeability there, does that have any modification to appliances?

MR. HRITCKO: Many appliances do not have to be modified. There are areas where you have to have, particularly in process gas and utility users where they have, like I say, processes that are peak-shavers, pre-treatment will be affected by having, say, higher ethane in the gas stream, but many of appliances perform perfectly well at the higher Btu level.

MR. PARKER: The problem we had, even in the NPC study, we had all the parties here. We had the distribution companies, the pipelines, the LNG, the producers. We couldn't find consensus at the table to that exact question, so that's why we say somebody just step back, instead of looking at it from a Cove Point or an X, Y, Z pipeline and say okay, we need to look at this from more of a large infrastructure standpoint of we're really going to have this much LNG come onboard. Those are the questions we think we need to be delved into.

MR. HRITCKO: One other point: Not to belabor interchangeability, although it is extremely important, in certain markets, particularly California, Southern California, I know that, as a sponsor of the project in Baja, we've been very much concerned with interchangeability, as are the California markets, particularly on a yield-per-fuel basis.

They are looking to use natural gas as a vehicle fuel, and changing the quality specifications would, in fact, impact that as well. And we're doing a lot of work surrounding that activity.

(Slide.)

MR. SIKKEL: The last little bit of the supply story is summary. It's less of a summary than just sharing with you, a recap of some of the sensitivities that we ran.

I think we showed you most of these as we went through the story, except maybe the end points, which are the high-resource assessment and low-resource assessments that are in the ten percent probability range on either end.

(Slide.)

MR. SIKKEL: And what they represent is about a 35-percent change in resource base, so a big change in the resource base can give you the kind of price effects and volume effects that this shows.

The lighter gray reflects demand sensitivities that will be talked about later, but it gives you a bit of a sense of how these things wrap up and the relative size of the change associated with some of the cases we ran.

(Slide.)

MR. SIKKEL: And even more useful, if you look at the last slide, it just racks these up on a bit of a demand curve or it plots it versus the change in supply and the change in price. And it gives you -- you just sense again, the relative change caused by different sensitivities, and the consistency of the result in terms of the modeling effort which was done.

There were some other sensitivities that were run. These were just some of the principal ones on the supply side that we're trying to illustrate.

MR. HEDERMAN: I don't want to go off on this as a tangent, but as long as I have this supply expertise in front of me, let me ask this: About ten years ago, I had some colleagues I worked with pretty closely at JNOC, the Japan National Oil Company, who were making fairly serious investment in hydrates as a supply option, which was way out of the ball park, because you had to get to $5 a million Btu for it to make sense.

Now that $5 a million Btu looks possible, are hydrates still out of the picture?

MR. SIKKEL: The technology team did look at hydrates. There is a writeup in the technology report about it. Their feeling was that it was still far enough down in the future that it really wasn't something that we should consider for these results, although in the latter years, they were a bit less certain about that assumption.

Out in that timeframe is when I think they felt there might be some commerciality. They also talked to how hydrates might grow, the rate of growth you might see, some useful thinking that may be of interest to you in the final report.

So it didn't make it in, but there is some commentary on it.

MR. CUPINA: One last question on the LNG presentation: On the slide it says competitive LNG potential. In fact, the value chain cost to the U.S., do those represent the range of marketplaces that are necessary to sustain this kind of development in LNG?

MR. HRITCKO: What those represent are the delivered price out of the re-gas facility into the North American market. We factored in from various locations, whether it be in the case of the Middle East, the Atlantic base, or the Asia-Pacific, from the wellhead all the way through the regasification process and adding up those costs.

And that would be a delivered price that you could achieve those supplies into that particular region, whether it be Gulf Coast or West Coast.

MR. SIKKEL: That really completes our supply review. And we'll pass it on to David Manning.

MR. MANNING: Thank you, Mr. Chairman. We're going to switch panels here.

CHAIRMAN WOOD: Let's take a stretch.

(Recess.)

CHAIRMAN WOOD: Let's get together and talk about demand. We'll go back on the record. David, you're on.

Okay, panel two. The outlook for gas demand.

MR. MANNING: We'll be fine, Mr. Chairman, thank you.

We have, as you can see, reformed our panel. I'd like just to introduce the presenters from our demand group. We have Keith Barnett who heads up Electric Power, Harlan Chappelle who has been my assistant in this role, and Dina Wiggins, general counsel for Process Gas Consumers. So I'm going to introduce the demand section if I could.

(Slide.)

MR. MANNING: I'm going to take you to our first map. As you can see by the pie charts, there's a single message there and this is certainly preaching to the choir. This is not only an important resource, it's an essential resource. I think on the left hand side as you'll see it on the map, it introduces some very interesting dynamics between the three elements of the demand which we are focusing on.

For the most part you've got a liquid power market. You've got for the most part regulated residential and commercial market. Then of course, you have the industrials that not only compete for gas supply with those two markets but also you compete globally. That raises a very interesting dynamic which we will pursue in this analysis.

Also, as you will not, Mr. Chairman, as you did raise the issue of consumption within northern Alberta within the oil sands -- that is one of the issues that we have on the demand side because there are a number of extensive projects which are contemplated or in development in the oil sands. They are largely heat intensive and gas intensive, but there's also a great deal of work going into substitute gases at each source and also to drive efficiency.

So while there's been a great deal of speculation as to the demand, the consumption of the Canadian Frontier pipe, there is no clarity on that, I would suggest.

There is certainly an outcome which sees some new supply but we spoke to that earlier.

(Slide.)

MR. MANNING: If I could just talk about our approach for a moment because I think this is very significant, just back to those refilling issues.

As you can see, we have some pretty intensive gas use. That's going to come up as it's addressed by each of our panelists.

(Slide.)

MR. MANNING: Sector by sector I believe is important. Our previous study which was done in 1999, was a product of the era of the 30 Tcf rule but, to some extent, the challenge of the study was to enter that debate in terms of how are we going to get there. There's a debate going on between different sectors but, for the most part, a demand number of 30 Tcf was assumed as Jerry Langdon pointed out at the outset -- we have a different market picture now.

As a result, this analysis I think, has been very robust. We have got a very significant review of the electric power, both in terms of current capacity, anticipated capacity and fuel choice, led by Keith, which he will address.

We have a pretty significant review of the industrial gas process obviously focusing on those which are more gas intensive. We also of course throughout will also be evaluating the role of efficiency within these markets. We also had an LDC team. I'm going to turn to that in just a moment, and those who participated -- but we looked at efficiency already achieved and efficiency going forward.

You should know that the U.S. and Canada achieved in concert a single demand model and we have modeled Mexico as an end point and received some help from DOE in terms of getting a better understanding of that market.

(Slide.)

MR. MANNING: Very important, as I indicated, we have -- economy and demographics was one team led by Les Deman. We do, of course, have Dena and Keith here. We also have a residential and commercial led by Ron Lucas.

What you see are the core companies who participated in the demand study, but we also had regional both in terms of use and in terms of the region.

We had a very good outreach effort. We had a number of open discussions. We had day-long workshops with respect to a number of participants beyond that listing. I think it's very important that, in the power sector, for instance, we had major gas consumers who were also large nuclear providers. We had major gas consumers who had large use of coal. That was our intent.

(Slide.)

MR. MANNING: Turning to our findings, if I can call this, this is our distilled findings of the demand group in this study. First and foremost, greater energy and efficiency and conservation for both new and long term mechanisms to moderate price levels have reduced volatility.

Of course, because of the lead times required, we would see efficiency and conservation as the most immediate opportunities for the volatility, which continues to be a major issue that we're asked about.

Number two, power generators and industrial consumers are more dependent on gas fired equipment than they were previously and are less able to respond to gas prices by utilizing alternate choices of energy. Very important issue for volatility and an important issue to discussions of the peaks that we faced last year.

Thirdly, gas consumption will grow but that growth will be moderated as the most price sensitive industries become less competitive and some industries and associated jobs reload outside North America.

Once again, very important issues are being faced in this study.

(Therefore, the objective is to improve demand flexibility and efficiency. Recommendation number one -- I'm giving you the distilled version again -- encourage increased efficiency and conservation through market oriented initiatives and consumer education and recommendation.

Number two is to increase industrial and power generation capability to utilize alternate fuels.

Our analysis now begins. We are going to show you the demand outlook.

(Slide.)

MR. MANNING: We're going to view macroeconomic indicators, industrial demand, power, residential and commercial, and I'm going to turn it over to Harlan Chappelle to talk about that.

MR. CHAPPELLE: Thanks, David.

(Slide.)

MR. CHAPPELLE: This is the demand outlook. We'll come back to that. The big picture here is we've been through a period of about two percent per year growth. What we see in our scenarios, both the reactive and with the balanced future, is balanced growth -- it's about a two percent a year growth. And as we go through this, you'll see how that is built up in these major sectors here.

I would point out that the co-generation swath was facilitated by EIA's changed reporting. As you can see, it is a fairly significant piece of the puzzle here.

(Slide.)

MR. CHAPPELLE: Trying to describe natural gas demand is essentially trying to describe how our economy behaves. We had to make some broad assumptions in our model. These are averages. It is important to understand that. But it hopefully is transparent enough that people can understand and see this, through varying assumptions that they might have.

The key macroeconomic assumptions here are GEP growth. We've seen approximately 2.8 percent in the year we're in currently and then 3 percent per year thereafter -- industrial production, 3 percent per year, Canadian GDP growth, 2.4 going to 2.6 percent and an inflation rate of about 2.5 percent.

I'll show you two slides that will hopefully put this into a little bit of a context. Other key assumptions here -- and these are as the modelers say, "exogenous" inputs to the model -- weather, 30 year NOAA average; oil price, WTI $20 per barrel flat in real terms after 2004, and then other key substitutes for or alternatives to, gas are listed there.

(Slide.)

MR. CHAPPELLE: GDP is, with all experience, fluctuates all the time. What this graph basically shows is that fluctuation through time. The spikey part. The others are simply averages. Our group of economists looked at this and we had a broad range of economists from different parts of the energy participating in this group. They used this kind of data to say, we find it credible to assume, if we're going to have a number of 3 percent per year GDB growth, from that comes a lot of demand assumptions, because our economy, being so gas and energy intensive in general, our energy use is highly collated to GDP growth.

(Slide.)

MR. CHAPPELLE: Industrial production. I don't want to spend a lot of time but I just want to make the point the 3 percent number is one that represents the whole basket of industries. It's the complexity of this diagram and the differences in different sectors that led us to some of the things Dina Wiggins will talk about and how we felt it important not to go as had been done in previous models, simply using a plug number for quote industry but to try to break it down and get more descriptive. We think we've made a step in the right direction there.

(Slide.)

MR. CHAPPELLE: Data also mentioned. These are just big picture issues before we get on to the actual demand sectors, the importance of efficiency. Many would say that efficiency is the source of supply. That would be a good way to look at it.

If we wanted to look at efficiency as a source of supply or reduced demand, each of our sector reports actually goes in and looks at historic energy efficiency. This is somewhat of a cartoon because it assumes something that we don't believe would happen, that is, that we wouldn't actually have efficiency gains in the future. But it is descriptive and illustrative of the continuing contribution of the market's reaction to higher prices and decisions that individual consumers make to change their water heaters, to put in more efficient air conditioners and for power generators to go to combined cycle instead of steam boilers, and for industrials to change out boilers.

That wedge out there in 2025, 5 plus Tcf a year, represents notionally the contribution of continuing to drive for energy efficiency.

CHAIRMAN WOOD: When you hear the phrase, "demand destruction," is that included in that or is that a separate issue?

MR. CHAPPELLE: That's a separate issue. That would be in that main body there.

With that --

(Slide.)

MR. HARVEY: Can I ask a quick question? You used some macroeconmic assumptions to feed the model. Did you spend any time thinking about the macroeconomic implications of the price paths coming out of the whole model? I know that's not what you were designed to do, to run the model, but any discussion of that --

MR. CHAPPELLE: Absolutely. It was an iterative process. We asked ourselves those questions over and over. In fact, we did some sensitivity analyses to try to understand what the implications might be. It's all part of that process and this $20 a barrel, what would happen if it was different than that? What if GDP growth was higher or industrial production was higher? We had an economic rebound.

MR. HARVEY: Anything in terms of through the '90s we saw $2.00, I guess in real terms, two, two-fifty natural gas in a war with plus or minus $5.00 natural gas coming forward. Did you all kind of look back and say, "What might be the macro implications of that?"

MR. CHAPPELLE: In a simple phrase, yes, we did look back and asked ourselves what that would be, but we really had to apply it to the individual sectors. How did they behave? How did they respond? And yes, it's a great point.

With that I'm going to hand it over to Dena Wiggins to talk about industrial demand.

(Slide.)

MS. WIGGINS: Thanks, Mr. Chairman.

I'd like to cover three areas in this overview of what we did in the process to look at industrial demand. First I'd like to give you some background on the industrial energy consumption.

Second, I'd like to go into a little bit of a process and modeling effort that we have undertaken in this study and third, then, I'd like to go into some conclusions that we drew and the findings that we came up with in the process of conducting the study.

The first couple of slides that you will see up here are what I call the "why do we care" slides. These slides are designed to show why the NPC in conducting this study decided to look at industrial demand and spend this kind of time modeling industrial demand as we did in the study.

Starting with the regions, you can see that there are a number of regions where the industrials consume a fair amount of energy, the west south-central, the east north-central, the east-south central, the south-Atlantic, Pacific and middle Atlantic.

You can also see that, in all of these regions, industrial consumption of gas, which is the green bar here, is either comparable to or exceeds the consumption of other types of fuels, industrials use natural gas for a variety of reasons. Sometimes because it's clean burning and enables them to comply with environmental restrictions. Sometimes.

In particular industrial applications it's the preferred fuel. They just prefer that fuel because of its burning characteristics to other fuels.

Also, at least in the past, natural gas has been relatively cheap. We've seen some changes in that recently.

(Slide.)

MS. WIGGINS: This is a busy slide, but it has a great deal of information in it that informed our analysis. I'd like to spend a few minutes on this one. Here again in the upper left hand corner, you can see that the industrial sector is the second largest energy consuming sector of any of the other sectors if you take that natural gas consumption piece out of that. That's the blue part of this bar and if you break it into the component parts, you can see that natural gas is not consumed by all industrial sectors in the same amount.

As a matter of fact, and this gets back to what David and Hal were talking about earlier, there are seven industrial sectors that are the key energy consuming sectors, chemicals, petroleum refining, paper, food, stone cleaned glass and primary metals.

Also you can see in the upper right hand corner, industrials use natural gas for a variety of reasons as feed stock, process heat, boilers and other.

These facts informed our analysis and helped shape our approach to this modeling effort. Rather than looking at industrial demand as a monolith, as we had done in prior studies, we decided to investigate natural gas demand by industrials with more granularity than we'd done in the past, so we focused on those seven gas intensive industries.

We also focused on the primary industrial uses of natural gas, which are the top bars, left side.

(Slide.)

MS. WIGGINS: We then relied on EEA for modeling our industrial demand and we relied on their extensive compilation of data that they have put together over the years, data that is not otherwise publicly available. We had a lot of fun in this process, sort of teasing each other as to who had the hardest job. And without telling all the ins and outs of that debate, I will say that it was a challenge for the industrial sector because of the lack of publicly available data.

As I said, we relied heavily on the EEA compilation of data and also we went out and conducted an extensive amount of outreach efforts. We involved representatives from those key natural gas consuming sectors. We had additional data from them and we used the expertise in those groups to test our efforts and to test our preliminary results.

(Slide.)

MS. WIGGINS: Particularly, we use those outreach efforts to test demand sensitivity. In our modeling efforts, we were at the upper end of the historical norms. And there was not very much data to calibrate sustained higher natural gas prices and how those would impact industrials. That was one very important outreach effort that we undertook.

For example, one thing that we decided to do as a result of those efforts was to assume that for industrial capacity that was idle for more than two years that would be a program that would shut down and would never come back on line. And that gets to your point, Mr. Chairman, about demand destruction. There had been previous efforts undertaken that assumed that once natural gas prices moderated those closed plants would come back on line. Through our outreach efforts, our industrialists told us that's not a realistic assumption.

At some point, once our plant has been offline, it will never come back on. We also used our outreach efforts to get insights as to how the various industries used natural gas and what kinds of drivers impact their future use of natural gas. This slide summarizes the information that we received in that outreach effort. This just hits the highlights of some of the key gas-intensive industries.

Chemicals is primarily used as a feedstock and for steam and process heat. The demand growth will be driven by co-generation and hydrogen needs. For petroleum refining, it's used as steam generation and process heat. The demand growth will be driven by hydrogen, co-gen and heavier crude feedstocks. For paper it steam generation and lime calcining. Demand growth will be driven by co-generation and process reconfigurations. For primary metals it's process heating and lower demand and increased competitions from imports will affect their future.

(Slide.)

MS. WIGGINS: The next couple of slides summarize additional information that we obtained from our outreach efforts. And in some we had our industrials paint a relatively gloomy picture of expected industrial growth. It's reflected in the current economic down turn.

There are also, in some sectors, a concern for the long-term viability. One of the interesting things we found out is that the price of gas for some industries is not the primary driver. There are other things that are the primary drivers, such as labor prices, raw materials, proximity to markets, exchange rates. And for some consumer products, and this gets to a point I made earlier, there's a preference for natural gas. They will continue to use natural gas regardless of the price unless it gets too high. In which case they will just shut down. But there is a preference for wallboard for natural gas for drying because it ends up with a clean board.

If you switch to something like resid, it can leave kind of an oily residue on the wallboard and consumers don't like that. There are also regulatory limitations to energy-intensive retro sets. A number of industrials told us that even if they want to go out to retrofit existing fits to make them more energy efficient, they are prevented from doing so because of resource review processes where it's very difficult from them to get the necessary permits. In particular, from the bulk paper industry, we heard for a continuation of PURPA or something similar to continue their use in CHP.

(Slide.)

MS. WIGGINS: One of the things that was very important in this process had to do with fuel-switching capability. I've said before this Commission before that I think there is a common misconception that for many industrials if you want to stop using natural gas all you have to do is go to the plant and flip a switch and you can all of a sudden use something else. It's just not that easy.

The last publicly available data that we had was from the Department of Commerce, e.g., a MEC study. That showed a 20 percent capability of fuel switching. The industrial we met with would simply have laughed at that number. It is not a credible number for them at all. So we used the input that we received in our industrial outreach efforts to dial that number back for the purpose of this model. We used something in the range of 5 to 10 percent fuel-switching capability.

CHAIRMAN WOOD: That means 5 to 10 percent of the total MCF consumed by these customer classes could actually be displaced by oil.

MS. WIGGINS: Or some other fuel, right.

CHAIRMAN WOOD: That's low.

MS. WIGGINS: Yes, it is low. Actually --

CHAIRMAN WOOD: Are they just not making good processes now with fuel switchability like the power plants?

MS. WIGGINS: In part that's the answer, but I think there are a number of factors that have impacted that fuel-switching capability. In part I think it's that there are some industrials who, at one point in time, had fuel-switching capability and they gave that up. We heard anecdotal information that in order to get permits to expand their plants, for example, they had to give up fuel-switching capability.

Sometimes people, just because of perceived local opposition to any other use of fuel other than natural gas don't have that capability, and perhaps, never had it. Sometimes it is because of capital investments; in an era of economic downturn, it requires money to maintain a dual-fired system. And some industrials have just decided that it wasn't worth that continued investment. So it's really a variety of factors driven in large part, as we heard, by some of the environmental restrictions.

MR. HEDERMAN: I'd like to thank you for coming up with that estimate. Since I took this job, I've been alarmed at how little I could find out about current fuel-switching capability.

MS. WIGGINS: We were alarmed, too.

MR. HEDERMAN: In your review, do you think this is a good enough number to be able to be using it? Or is there still a need to do an assessment of this, either at EIA or some place else?

MS. WIGGINS: I would welcome a more rigorous assessment of this. From the meetings that we've had, I feel confident that this is an acceptable range for us to have used in our modeling efforts. But I certainly think it would be worthwhile to have somebody come in like another EIA Department of Commerce study and really scrub that number.

MR. HEDERMAN: Thanks.

MR. PINKSTON: At today's prices, one more question on that. This 5 to 10 percent that's waiting to be switched or would it be switched now?

MS. WIGGINS: It's capable of being switched.

MR. PINKSTON: But still currently burning gas?

MS. WIGGINS: It could be. It's not how much has been switched at any point in time, if that's your question. It's what is sitting there that could be switched off to another fuel. That would be starting out using gas and then could switch off from gas.

MR. MANNING: And will add to that. In the Arctic sector we have the same issues there. But certainly that capacity is fuel-switching based on pricing, presumably. But of course, Mr. Chairman, as you know, we have occasionally had approvals for power generation at the state level. At the local level, we've been prohibited from doing that in new generation sources. So you see the same thing happening on the industrial side.

They've had to give up often because of local support, or lack of support. They've had to give up that capability. But where we talk about switchability, presumably.

MR. HEDERMAN: You may what to confirm this, but on an industrial and electric, this is dual-fired capability. You can make generation decisions or consumption decisions based on price.

(Slide.)

MS. WIGGINS: Here's some additional information from our outreach efforts. I just want to pause on the bottom half of the slide. Our outreach efforts consistently reflected industrial concerns over recent higher natural gas prices and a belief that the higher natural gas prices are detrimental to the industrial sector.

Industrials have less demand response of this than in the past due to environmental restrictions and gas-favored process investments. There's a fundamentally different downstream market for products that's less liquid and less transparent. And there are non-domestic factors that impact natural gas demand -- world markets, emerging economies and things of that sort.

(Slide.)

MS. WIGGINS: I'm going to go very quickly through these next few slides. The main point of these slides is to show that because of the importance of the chemical sector to this analysis -- you'll recall one of the earlier slides -- they are the largest natural gas consuming sector among the industrial. And because they use a lot of natural gas as feedstock, in our modeling effort, chemicals was modeled very differently than the other industries.

There will be detailed information in the integrated report about those industries. If you want to pursue that today, there are other folks here who can respond to those questions. I'm very happily to be known as a FERC geek, but I'm neither an engineer nor a modeling expert. I know a lot more about modeling than I did at the beginning of this process. But the experts are here to answer those kinds of questions if you all want to pursue that.

(Slide.)

MS. WIGGINS: This gives both the model input and the outputs from our modeling efforts. In sum, I think this confirms the gloomy picture for the industrial sector that we heard in our outreach efforts. If you can see in the historical period of 1992 to 1998, you will see relatively higher industrial production and growth rates. And I believe just about all of the sectors up there -- gas is relatively higher in the historical period than we're projecting into the future.

In the future of 2001 to 2025 you'll see that the total industrial production growth rate is only expected to be 1.1 percent of actual drop off and actual gas consumption.

(Slide.)

MS. WIGGINS: The final slide summarizes our findings for the natural gas consumption for the industrial sector. We're seeing low growth to no growth for the natural-gas-intensive industries. We're seeing the competitiveness of individual plants and industries threatened, with some of the industrials being particularly on the bubble. In particular, ammonia, methanol and primary metals will probably experience additional demand destruction.

There is significant stress on North American olefins, particularly, the ethane-based ethylene. You can see in the lower left-hand slide on the history there was much more consumption of natural gas in the past than we're expecting for in the future. That trend is also true for the end uses of natural gas as well. Keith?

MR. BARNETT: Thank you, Dena.

(Slide.)

MR. BARNETT: I'd like to start by talking briefly about the process. I don't have any specific slide. The power group also conducted outreach meetings. We conducted three regional outreach meetings and have attempted to get stakeholders to come in and discuss with us investment decisions, dispatch issues, fuel issues, emission limitations and a whole range of things that people who make investments in and operate power plants face.

I think those meetings were successful. And I'd like to publicly thank the participants in them as well as the power team that worked along side of me. Much of the credit for the product goes to their thoughtfulness and their rigor in analysis.

Moving to the first slide that we have.

(Slide.)

MR. BARNETT: You saw earlier that natural gas is important to our nation, and it is very important. But I would say that electric power is even more deeply woven into the fabric of the lives of Americans, Canadians and Mexicans. It just touches our life in so many different ways. As GDP growth changes, so does electric power. It has, it is and it will continue to grow as our economy grows.

Back in the 1950s and 1960s, the way that power consumption actually grew faster than GDP electric power consumption grew faster as the electrification of the country and the saturation of electrical appliances began to occur, roughly coincide with the higher energy prices of the early '70s, that relationship changed and has been on a relatively constant straight line, as shown on this graph, since the early 1980s. We've assigned a coefficient of .72 to the change in GDP as it relates to the growth in power demand.

As Hal mentioned earlier, we did have a team of economists. The term "herding cats" come to mind because they gave me a lot of help with this .72 number.

(Laughter.)

MR. BARNETT: I learned about macro-economics, micro-economics, and super-economics, regressions that I didn't think you could do the way they did them, and a variety of other approaches. Point 72 is the number. We'll revisit that briefly, but we've exhaustively pursued this. As gas fuels more and more hours of the need to supply electric power, it will become even more closely coupled to GDP than it currently is. It's become a fuel of choice for power generation. And as I move to the next two slides, I would comment that there's potentially some profound implications of what you'll see on these next two slides.

(Slide.)

MR. BARNETT: I call it potentially profound. If you look at that wedge right there of power generation capacity, that's not a model projection. That's iron on the ground or iron that's being constructed on the ground. This country has built somewhere between 200 and 220,000 megawatts of gas-fired generation going back to '97, '98, much of which is not dual-fuel. You made that comment earlier, Mr. Chairman, and it was a true comment.

That's potentially profound because as it sits right now this generation capacity is available, ready to run when the economic climate, when the demand for power and the weather or economy or the local regional supply of generated capacity calls for it, it will run.

Early in the process a question came up at one of our meetings. Are these just going to be bark turbines, much like bark fiber occurs in the fiber optics world. The potential certainly exists for that. But the reality is other people are not going to make investment decisions to build to capacity to replace this. We spent, as an economy, $100 billion putting in this capacity and it will run.

I will tell you it's going to consume natural gas. And it shows the projections out into the future of what the capacity mix will be. You see continued contribution from coal, albeit, at slower than past rates of growth. This case, by the way, is the reactive path generating capacity. In there you see a continued, steady increase in renewables. We'll talk about what drove that renewable capacity growth as well.

(Slide.)

MR. BARNETT: Moving to the new slide, which is again zoning in on just the gas-fired capacity, on the projected side it actually shows up a little bit better than it does on the projected slide. Also, underneath it we had the EPA non-attainment areas. I apologize. You can't really see those on your slides.

Here are the three key points about this slide.

First, the gas-fired capacity that's going to be built in every region except the Pacific Northwest and MAPP, more than half of it is already built or will be built by 2005. Notwithstanding the fact that you cannot see ECAR or MAIN on there, that's also true for them as well.

However, I looked at this slide earlier and what happened to ECAR. I ought to know a little bit about ECAR since I work for American Electric Power. And I can assure you they do have some gas-generating capacity. We'll touch on that again in a little bit. I will point out these ozone non-attainment areas in the Northeast. There are some down in the Houston and Dallas areas and then the rest -- southern Arizona, much of California, parts of southern Oregon as well are all non-attainment areas for one of the EPA designated pollutants. That will be important to remember when we talk about some of the new growth assumptions that occur.

(Slide.)

MR. BARNETT: The next slide, again, is a reactive path. What it attempts to illustrate is the model projected results -- just how much projected electricity will be generated by type of capacity out into the future. You will note that coal continues to be the primary contributor of electric generation in this country for this study.

Green people thought this was a very profound thing since this is a natural gas study. The study leadership encouraged us to just do what we needed to do and look at the process in the most fair and forthright manner and make the assumptions based on the accumulated wisdom, as they called it, wisdom and judgment of the power team.

You can see that nuclear and hydro-electric are constant. Both of those are exogenous input into the model. The model did not dispatch those. I will talk about that a little bit more when we do some capacities. So if you have questions on it, I'll be happy to address it now. But gas does continue to grow substantially as a contributor to the annual generation of the country. Moving to the model assumptions for a new generating capacity.

(Slide.)

MR. BARNETT: Essentially, the model is set up to where it calls for new capacity when reserve margins are projected to be hit due to electric power demand growth and existing supply stack. These are assumptions for new-built capacities. We'll talk about some other assumptions momentarily.

We made the judgment that there would be no new coal plants built in the non-attainment areas of the East Coast or in any of the states abutting the Pacific Ocean. They're just not going to be able to permit and build those coal plants there. That's an assumption that's based on our judgment. Other people can dispute it. And there have been announced projects in those areas. I'll just leave it at that.

In addition to that, though, we didn't allow the model to build coal in the regions where we allowed coal could be built before it hit those reserve margin thresholds under the theory that if there were margins to be made, people would look at it and to make investments in fully environmentally-compliant coal to attempt to capture, as a merchant generator, the margins that would potentially exist under an environment where gas prices are higher than they have historically been.

We limited coal in Florida. And we also limited it the total amount of coal to 14 gigawatts per year. And I'd also say that the model results never actually were impacted by that. They go right up to that limit. But actually they could have built a little bit more before they bumped up against that particular limitation.

We also made the assumption that for renewable generation capacity would be able to economically compete in the reactive path. We primarily ended up with renewable and we chose wind as the proxy for all renewable without, in fact, saying they are the winning technology. And I want to emphasize that the NPC, in general, and the electric power team, specifically, was not in the business to pick winners and losers in terms of technologies or individual power plants or any of those aspects of it. We just made these broad-based assumptions.

In the balanced future we almost doubled the amount of renewable generation up to approximately 150 gigawatts of installed capacity. And it was geographically diverse around the country, the reactive path. It was more concentrated in the western United States.

We also went to some differing, alternate fuel capabilities between the cases. And then after each case, we looked at the emissions that would have occurred under that generation capacity and how it dispatched to ensure that no current environmental emissions would be exceeded.

MR. MURRELL: Before you move on, when you used reserved margins as a trigger, were those reserve margins comparable to the reserve margins that each region uses for reliability purposes or was this more of an economic figure?

MR. BARNETT: We tried to do it in the economic figure. Fifteen percent was the proxy that was used. We were looking at broader -- we've going to certain states and control areas. We were looking at it on the NERC regional basis. I do believe in two regions it was a little bit higher than that. It was as high as 18 percent in one of them. Does that address what you needed? Okay, really it was a reliability issue, not just economics.

(Slide.)

MR. BARNETT: On the next slide, and I don't want to spend a lot of time on this. These are the primary generation technologies that we allowed to compete. Just simply put, these are ones we chose. We noticed that hydro-electric is not up there as a primary technology to compete. The reasoning is because those were exogenously placed in megawatt hours that the model touched on. I'll describe those assumptions in a moment.

The bottom line is that gas-fired technology won frequently, and coal, the super-critically wholly-environmentally complied was also the winner in terms of the primary generation capacity. Again, renewables were assumed to compete, but by and large, the absolute magnitude of those were a little bit more force-fed into the model process.

One of the reasons gas competes so effectively is, look at those lead times. Your market investment risk is so much shorter that you're able to make those. You're able to build smaller plants. You're able to get them sited. Your overall investment risk criteria is substantial.

I also will need to, after this point, broach the subject that came up in the earlier discussion around LNG and the interchangeability of it. I would just say that I would point back to Scott Parker's comment earlier. If and when the FERC begins to address pipeline quality gas standards, you need to have a pervasive, extensive stakeholder effort to make sure that you get it right.

The combined cycle -- the question was asked about combined cycles. People that have invested in the combined cycles and combustion turbines have warranties with the manufacturers. Those can be impacted by the dew point, the gas qualities, and the liquids in the gas or potential liquids in the gas as well as -- maybe more critical -- the environmental controls on these plants are tuned for the gas quality that we have in this nation.

I'm not saying don't do anything. I'm saying make sure you reach out extensively. And I would point back to Scott Parker's comments, just make sure you're thoughtful about it and take the appropriate amount of stakeholder input from all levels.

MS. WIGGINS: That includes the industrials, right, Keith?

MR. BARNETT: I told Dana I would include industrials.

MS. WIGGINS: I don't want to get left out here.

MR. BARNETT: I had previously been a gas supplier to the Timkin Company in Ohio where the fluctuation in gas BTU that they had over the cycle of a year had profound impacts on their tapered bearings. In the summer when the interstate gas isn't flowing up there, they had to throw away, sometimes, hundreds of thousands, if not millions, of dollars worth of products at the end of that. So it's a significant issue. Don't take it lightly.

(Slide.)

MR. BARNETT: Other modeling assumptions related to electric power is very critical. Low growth remains coupled to the GDP growth on the reactive path over the time period of the study. We reduced that coupling effect from .7 to .62. That has an impact. In the balanced future, we reduce it from .72 to .55. You can actually see the difference by the Year 2025 in the amount of electric generation created by just this efficiency.

Input -- we assume that hydro-power capacity remained unchanged. And that the annual gigawatt hours were sort of historic averages provided by region. Of course, individual hydro power facilities are constantly trying to upgrade and increase their capacity.

We also know there's an ongoing effort to maybe remove some of that capacity from the market. We're not here to pick winners and losers. We think, to the extent that you do lose capacity in the relicensing process with improvements in the other capacity, by and large, may make it up. That was an assumption and it's something that you'll have to examine very carefully -- at least, for those that are under FERC jurisdiction.

Nuclear plants will have at least one successful relicensing, every single one of them. Again, we don't pick winners and losers. In the reactive path, the actual capacity growth would be limited to 2 percent. And that would all occur by, I think, 2012.

In balanced future, you actually have 10 percent capacity increase. On the books right here as we sit today is approximately capacity increase that is proposed over the next 10 years. American Electric Power just recently received a small upgrade in its Cook plant. We think these will occur. But again, we think the difference between these two cases is that we're not naive enough to believe that every single one will get relicensed. We're not picking winners and losers. But we're just saying that capacity creep will take care of some of that.

A really major distinction between the two cases is the impact of the EPA regulations, which are due to be promulgated in draft form this December. Depending on the nature and scope of those regulations, we have presumed potentially 20 gigawatts of coal-fired capacity being retired in 2009 and 2010. That capacity, frankly, the assumptions are very quick to describe 40-year-old coal plants, or older, 200 megawatts or smaller, not coal-located with a large unit where you may get another impact from it.

Or based on my judgment, and a couple of my team members' judgment, not critical plants. There maybe a few plants that because of a variety of issues could be determined to be critical. And we came up with 20 gigawatts. Frankly, depending on those regulations, it could be half that. It could be two and half times that. It's a pretty important issue to the country over oil and gas steam units continue to retire through 2010. And frankly, we went back and forth on this issue substantially. Other than to say that people are, in fact, retiring some of the older dual-capable units. We finally decided to back and allow some of them to retire, even in the face of higher gas prices based on the projections in this study.

We've also showed transmission capacity between regions increasing by 50 percent over this study period. This is not gas transmission. This is power transmission. Without getting into a laborious explanation of EEA's model, in this particular case, what this essentially does is take the historical interchange between regions and increase that by 50 percent on an annual basis over the life of the study, which would, in effect, allow lower cost generation to flow into higher costs areas and then post-processing after each one. We look to see does it still make sense that this region was higher cost versus the other region. If it did, then we allow that run to stand with those increased interchange flows to occur.

We didn't attempt to model market rules, market designs, transmission congestion. We didn't have the capability in our model. Nor were we really charged by that by the NPC to do so.

(Slide.)

MR. BARNETT: We have what I call "directly coupled sensitivities" and "indirectly coupled sensitivities." The chart after this, which we'll move to in a moment, really only touches on the high and low GDP growth, high and low ratio of record low growth -- that's that .72 factor -- to GDP growth. The fuel flexibility case had, of course, the primary reactive path and the balanced future cases.

We also looked at the results of the weather-sensitive data. We looked at the results of higher oil prices. And then we ran a case that we've called the carbon reduction case just to see what might or might not occur. None of those are put on the graph. The graph is already busy enough without them. But just to let you know that we did look at those specific models.

(Slide.)

MR. BARNETT: I would point to the two most bold lines on the path. The red line being the reactive path and the green line being the balanced future.

The balanced future ultimately results in less gas being consumed by electric power. It occurs because we don't have to have as much power. Remember we have a lower coefficient. We have much more fuel flexibility, more coal is built in this case, although not a great deal more, substantially more renewables. There is a host of reasons why that has occurred. More oil is built as well, particularly, at the end of the study.

But you can see there's a wide of potential outcomes approaching 3 trillion cubic feet differential between the highest case and the lowest case of the sensitivities. That, in and of itself, is roughly a 10 percent swing on the North America market, and I'm not including the Canadian sensitivities in these. That's a pretty profound range of outcomes.

I would also point to the initial divergence between the green and red lines. Back in the 2009/2010 time period, when they begin to diverge significantly -- that is directly pointed, that assumption, around the coal shutdowns. That's where the spread begins.

(Slide.)

MR. BARNETT: I'd also like to touch on -- Andrew had asked us, as we were preparing for this, to ensure that

I did touch on power and gas markets. Clearly, they're an important factor in our evaluation and analysis. But I will intersperse a couple of comments here and try to identify those. But it may not be directly, shall we say, the NPC analysis. There would be an outcome of other work that I've done for my company or for Edison Electric Institute. But the natural gas market and the power markets are connected. And they're going to get more connected. This particular slide shows the 2002 generated capacity and the amount of electric generated by fuel type.

I guess I would point first to ERCOT SPP. As you can see from the slide, it has the largest area where natural gas produces power. I can also tell you, though, that people who analyze this for a living would suggest that natural gas or natural gas and oil are on the margin in ERCOT -- not ERCOT SPP, but ERCOT alone. Something over 95 percent of the hours of the year.

We grouped these together in a large macro way just to make the chart readable. But in ERCOT, for example, when you look at the correlation between power prices and natural gas prices, you see that in the two-month out and longer dated contracts were people are trading futures, whether they be financial futures or actual NYMEX-type futures, that the correlation between gas price movement and power price movement exceeds 98 percent for most of the seasons of the year.

As you come to only one month, and further up, that drops to something in the low 90 percent. And then you get to the day-ahead market, the correlation drops down. Again, depending on the season of the year as low as 40 percent to as high as 80 percent.

MR. BARNETT: The annual average is roughly 50 percent for the day ahead. And correlation of course just means that markets are moving in the same direction within the same band.

Even the Cinergy market, which is up in ECAR, where you can barely see the gas wedge -- the two-month out correlation between NYSources, Columbia Pool, and Cinergy Power prices is very highly correlated. If the gas price goes up, the power price goes up; if the gas price goes down, the power price goes down.

Only until you get to literally the day ahead and week ahead markets, where the market can clearly see the supply-demand fundamentals in power, does the ECAR market diverge and in fact is negatively correlated in a fair number of months around the summertime period.

But in the forward markets they believe and they trade as if gas was on the margin most all the time.

MR. HEDERMAN: As you started talking about this graph I was thinking, gee, I wish he did the marginal percentages rather than just straight percentages. Is that in the detailed study? Do you have that cut?

MR. BARNETT: We're going to get a person from CERA to put it -- that is their estimate. In my judgment it is a relatively good estimate. So in the detailed power thing there will be an estimate of the gas and oil on the margin by region.

I think it has got more regional breakdown even than this.

MR. HEDERMAN: Thanks.

(Slide.)

MR. BARNETT: Looking at the slide in front of you, once again going back we pointed out the profound implication of all the gas -- generations. This shows a multi-year history of the types of capacity that were added in the 60s and 70s, 80s, 90s. And then you see the enormous spike in 2002.

The real reason I put this chart in here is two-fold. One, to point out again that the markets are going to become even more dependent on natural gas than the markets have been in the power markets.

Secondly, if you look at the capacity additions in the late 80s and early 90s, had I been artful enough to have figured out how to put the ERCOT and ECAR price graphs on here in a way that didn't really crowd this graph up, you'd have seen that capacity was not built in those areas.

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Reserve margins were hit during unusually high demand periods caused by weather. And you had the price spikes in the power market. The power markets have their own supply and demand fundamentals.

As a consequence of those price spikes, the deregulation and the wholesale power market, the change in the philosophy of who is going to build, own, and operate power generation became the opportunity for people to invest. And they got a price signal that said we need capacity.

Some may argue that they may have overshot the mark, but the point being here that the gas-fired capacity has been built and it was built in response to supply and demand within the power markets.

Looking out over the next several years, post-2005, who is going to build what capacity?

With environmental uncertainties facing us with the long lead times around coal, with the prospect of high gas prices and hodgepodge of environmental regulations -- some that we know and some that we don't know -- and this large swath of gas-fired generating capacity, the investment risk is substantial for rebuild in the power industry. I'll just characterize it that way.

(Slide.)

MR. BARNETT: Looking at my last slide, we want to make the point that efficiency matters. If you look at the graph on the right-hand side, you can see that using EIA data with the annual heat rate for generation from gas-fired plants (and this includes some of the industrial as well), it runs from almost 10.2 heat rates to under 10 before it began to climb back up to 10.

Why did it climb back up? We weren't building anymore capacity so the less efficient steam units were being dispatched more and more. And so you just raised your average.

You can see the rather dramatic result of the new gas-fired capacity that's come on-line. It dropped from an average of 10.2 down to 9.2. And this is a nationwide average.

To give you some specific examples, both American Electric Power and Centerpoint have announced that they are mothballing some older steam units. Most of these gas-fired steam units also, by the way, have the ability to burn oil, be it number 2 or number 4 oil.

If you look at those units, having an average heat rate of 12, that they operate at a 50 percent capacity factor -- if those were replaced with the new combined cycles, and they are being replaced with the new combined cycles in the market, that saves 130 Bcf a year -- just shy of 300 million cubic feet every single day.

So AEP and Centerpoint have made the decision, rather than make our own electrons, we're going to buy from the market to supply our needs. Efficiency matters. As you get more and more pervasive here with combined cycle --

and the theory, as I have been told, behind some of the investment decisions was that people did anticipate just this sort of behavior occurring in the marketplace.

Here's an example of how it works and works well in ERCOT. There are other considerations. Some of them are just location, location, location that's required for voltage support, regional system reliability, the fact that they do have alternate fuel capability -- and that's been proven to have some value -- or that the regulatory impediments keep these on as well.

Particularly in places where you have multi-state jurisdictions where fuel costs flow out to the rate-payers across many states, the increased O&M, the state in which the generation capacity resides -- that's a tough one for people to choose to switch to oil or to buy and do certain other things.

So there are impediments that keep the older units on.

With that I'll turn it over to Hal for the residential and commercial.

MR. PINKSTON: I had a quick question. You mentioned a risk for generation investment. Would that be an issue in three years or five years? It seems like a lot of studies are showing a glut for the next five years. Did the model show that time?

MR. BARNETT: If you'll go all the way back to the new capacity chart, it shows very little capacity that's built until about 2010. First and foremost, I think we've only allowed it to build about two gigawatts of coal, because if it wasn't already under construction like the mid-American, which just started under construction, we frankly don't think they are going to get started.

We have a few of them embedded in there. Very little gasoline is going to be built. So most of the short-term stuff is renewable. And there's not a whole lot of that either.

So really until 2010 not a lot of capacity gets built because not a lot of capacity needs to be built other than a few very regionally constrained areas, where the finer granular level than we were modelling.

MR. BURRELL: Mr. Barnett, before we turn to the next, can you describe what you believe the current cut of fuel switchability in the generation sector is and how that's changing.

MR. BARNETT: Actually I appreciate the question. I kind of glossed over that.

If you look at EIA and FERC data for that matter, it suggests that in the existing generation fleet, approximately 150 gigawatts can burn oil or gas. Yet we do not see that behavior of that magnitude of switching even

when we had natural gas price spiking above $10.00. We certainly saw a lot of switching.
But we didn't see anywhere near approaching what that data would suggest.

Based on our outreach efforts, based on the publicly available data, it appears that certainly less than 10 percent and we think less than 10 percent of the new gas-fired generation that's being built has alternate fuel capability.

And we frankly assume going out that as much as a third that gets built will have alternate fuel capability in the face of a persistent higher gas price. Again, I kind of alluded to it a moment ago. There's some reasons why some people don't switch even though they have the capability.

In fact, one of the recommendations in the detailed area of the report is we are calling on the government in this case -- I think EIA -- to specifically go out. And we are in the process of modifying their form A-60 right now.

But to specifically go out either with that form further modified or some other survey and find out the reality behind the fuels, which frankly if you look at the form and if I have burners that can burn oil, I'd probably have to mark that I can burn oil even though my tanks were torn down 10 years ago and I don't have a pipeline.

Am I duel-capable or not? Theoretically I am. But reality? No. So it is substantially less than it would suggest.

Not speaking for the NPC study, but if you look at analysts out of Wall Street, if you look at entities like Cambridge Energy, Pyra, et cetera, they have an assumed number both in industrials and in power generation of how much can switch.

Those numbers do seem to be born out in the weekly and annual storage numbers for natural gas. However, if you go and analyze the DOE oil numbers and look at distillate and resid demand, it doesn't add up. There's a disconnect between the analysis you did looking at gas only versus looking at the oil data as to how much switching is really occurring today and prospectively.

(Slide.)

MR. CHAPPELLE: We'll complete the major demand sectors with residential and commercial demand. I'll try to go quickly through this and sum up and then talk about markets briefly.

(Slide.)

MR. CHAPPELLE: Just as with the industrials and with power generators, commercial and residential consumers have continued to embrace natural gas as shown in this graph -- growth in both customers and then demand.

(Slide.)

MR. CHAPPELLE: The key drivers in our modeling approach, demographics: where are people living, where are they moving to? Weather in the short-run clearly in this sector is the driver. Price response, more so in the long run, and some of this has to do particularly in the residential area with lack of price signal, if you will, to consumers.

We used again the EEA's model. It is regionally disaggregated. It looks at demographic trends-driven GDP. Regional population growth is the model for residential housing stock, commercial floor space, and a penetration of gas-based technologies -- new water heaters, pool heaters, that sort of thing.

The GDP elasticity that was in that model is based on historic data. The best data that we have in the United States is a 15-year period, 1984 to 1998, and then a smaller period in Canada.

What the model basically does is compare historic gas price responses to the price responses to the price elasticity during those periods. It's transparent. It may not be correct because of the timing and the price magnitudes. But it is a transparent model and is something we felt gives a good approximation.

Weather is clearly again the major variable in the short run, particularly for the residential consumers. Commercial floorspace tends to light whether it's cold or dark and run air conditioners and heaters and things such as that.

We did contrast two different scenarios as we've talked about. And in the balanced future we used a slightly higher efficiency gain than we did in the reactive path. The reactive path case continued to have the same efficiency gains that we have seen in the last 10 years or so.

(Slide.)

MR. CHAPPELLE: What are the bottom-line projections of that? In residential consumption, going back to some of the points that I just made, you see in the reactive path where you have more -- oh, I'm sorry, less energy efficiency than in the balanced future.

You see a higher consumption of gas for residential. And in the balanced future you see the efficiency effects.

You also see another commercial side. You see a little higher on the commercial side, basically a subprice response in the balanced future because you have a lower price in the balanced future. Therefore, the commercial consumers would use slightly more.

(Slide.)

MR. CHAPPELLE: This graphic shows you the difference in the efficiency trends over time. We've just selected three time periods and showed you what the difference in BCF per year would be in terms of efficiency gains in these.

We used a fairly crude approach to the efficiency gain, but again transparent. We assumed that if we had better market signals to consumers, if we had more consumer education, a number of factors would go into a consumer response in a balanced future.

This ties directly to our recommendations.

(Slide.)

MR. CHAPPELLE: The bottom line on a regional basis -- and again, just as with Keith, we looked at, we aggregated for display purposes. You see general growth at about one percent per year in these areas. And as I mentioned the first time that I spoke, GDP growth is clearly the driver here.

(Slide.)

MR. CHAPPELLE: So summarizing demand, we talk about our sensitivity analysis really quickly here. The key sensitivity analyses that showed us something we should focus on were, one, fuel flexibility.

Fuel flexibility -- we made a number of assumptions in each of the sectors. In the industrial sector, for example, you might remember the number that Dena showed you earlier: 26 percent of fuel switchability in the oil and gas boilers and other process units.

We used that as a target by 2025 that we could actually get back to. We progressively built that in and we made more aggressive assumptions in the power sector in terms of fuel backup.

As we've mentioned, one of the impediments to that, the local citing restrictions primarily, saying I know you have a permit or I know you want a permit from the state, but around here we don't want oil tanks. Around here we don't want oil deliveries. And so we don't want hire stacks.

That's true on Long Island and in Waco. So what we did was try to model a future in this particular case that would assume that consumer education would broadly -- in fact, be embracing some of this information at the state and local level and would allow people to make decisions on a more broad basis and say perhaps we would allow these facilities to have more fuel backup capabilities so they could respond to prices.

We also have four other cases there. And Keith talked about the electricity elasticity. In other words, what if we actually had greater electricity demand as a result of GDP growth? That would have the effect of higher gas prices and lower demand.

(Slide.)

MR. CHAPPELLE: This is another way of showing it like Mark Sikkel showed earlier for the supply side, the fuel flexibility being the most significant on average over the 25 years, about a dollar an MBtu difference.

(Slide.)

MR. CHAPPELLE: Here's the picture of where we would see demand growing in our modelling from today in the orange to 2025 in the blue. It's interesting we have the information probably actually more granular than this in our modelling.

And again it's a transparent framework. To understand assumptions and what the implications and the modelling results would be, the final picture that we showed is essentially one of the first.

(Slide.)

MR. CHAPPELLE: That is, this demand growth has been about two percent per year for the last decade or so, then has flattened out in recent years in response to a number of factors.

We see that flattening probably continuing in the higher-priced environment and a general increase -- you see it all averages out to about a 1% per year growth.

(Slide.)

We have two recommendations that David Manning went over with you earlier. Keith and Dena both covered this. The first of these is to encourage increased efficiency and conservation through market-oriented initiatives and consumer education. The subsets of those are shown there. Educating consumers, reviewing and upgrading efficiency standards, providing market signals to consumers to facilitate efficient gas use, improving the efficiency of gas consumption by resolving the North American wholesale power market structure.

If you think about what Keith said about the composition of his power team, you would imagine that there are more than one opinion on market design and the regional transmission organizations represented at the table. But all embrace the idea that the organized markets in resolving these issues would have an effect. And even the assumptions Keith made earlier and articulated for you would be the outgrowths of resolution of some of these issues. It does have an effect on investment in power generation and, in fact, when there's uncertainty we tend to default to the easy answer that's quick. That has been gas-fired capacity in recent years.

We need to remove regulatory and rate structure incentives to inefficient fuel use, going back to some of the issues that Keith talked about at the state or multi-state level. Perhaps you have a regulatory compact that actually causes you to make more money for your shareholder by running something that's less efficient, even though there may be more efficient alternatives in the market. We recognize the benefits of cogeneration. We uniformly indicate that there's a need to provide industrial cogeneration facilities with access to markets.

Finally, removing barriers to energy efficiency from new source review. Consistently, in the power and in the industrial sectors we saw this anecdotally and specifically. Time and time again as a reason that was cited for not making decisions that would otherwise lead to fuel flexibility and more efficient gas usage.

Our second major recommendation is increasing industrial and power generation capability to use alternate fuels.

(Slide.)

Providing certainty of regulations to create that clear investment setting, expediting hydroelectric and nuclear power plant relicensing. As Keith said, we're not suggesting winners and losers; in fact, we're not even advocating -- or approving relicensing here. That's not our role. But we are saying by expediting that it clears the air from an investment standpoint and it will have an effect on natural gas.

We need to take action at the state level to allow fuel flexibility. In our regulations, we tried to provide more granularity on something that's tangible at both the state and local level and go into some of the issues I talked about earlier, where you have integrated resource plans still in place, ensure alternate fuel considerations are there, allow regulatory rate recoveries, switching costs and support fuel backup. And, finally, in the power market structures -- and this is perhaps an action item for FERC as you look at standardizing the markets or you look at market designs, you would incorporate fuel switching considerations into power market structures. That's what would be an example of the way you'd do that.

An example of one that was given to us in a workshop would be tailoring the ICAP product, if you had that in your given market, to actual reliability, as Keith made the point, having iron in the ground that actually is listed as having dual-fuel capability doesn't necessarily mean it has it. That, in fact, when you have a regulatory compact -- Florida was an example of a place in that given jurisdiction, they actually were able to recover firm transmission on gas. We're not advocating one or the other, but these are two distinctly different settings and mechanisms for doing that.

(Slide.)

So flexibility and efficiency.

That ends, per se, natural gas demand. As part of his charter, the Secretary asked us for insights on energy and market dynamics.

(Slide.)

Our study did focus on the underlying fundamentals of supply and demand and the infrastructure needed to connect those. To do a full study of natural gas markets would be an undertaking of the same magnitude of what we already have done. So we felt it necessary though to at least share some of the insights that were gained, basic insights that were gained in the study on the natural gas market.

This provides our view on that, the North American natural gas market, the largest and most liquid in the world; price transparency and liquidity are fundamental. We've recently seen changes in which creditworthiness and the importance of that was reinforced. This is something you see everyday. Online trading operations again having declined; that's a difference in setting.

(Slide.)

We see as an example of that current levels of NYMEX trading below the peak, but still above the range of 10 years ago. There's fewer counter parties offering OTC instruments and creditworthiness of the remaining parties though has improved during this. What we found was that overall liquidity is sufficient to transact business at multiple hubs and access financial markets.

(Slide.)

We also found that volatility isn't new. This is a very busy slide but it's actually one that has a good amount of information. Red is the cash price at Henry hub, the blue and green are just the same information: volatility but seasonal, being winter is green and summer is blue.

As you see, volatility is not new, as I mentioned. It is an aspect of the market.

(Slide.)

It's also interesting to put natural gas in the context of two other related products that we've spoken of: electricity, more volatile; oil, less volatile.

(Slide.)

What are our conclusions that we would articulate in this study on natural gas markets? The market works. Price volatility is natural and a healthy phenomenon of a dynamic market. It's required to give consumers and suppliers signals. High volatility, though, does tend to increase uncertainty and decrease confidence in investors but consumers and suppliers do have a broad range of physical and financial tools to mitigate these. They do come at a cost. It may not provide consumers with the lowest price or suppliers with the highest price.

So, in essence, it boils down to these recommendations:

Government policies should promote free market solutions, transparency, safeguards against noncompetitive behavior and foster timely, accurate supply, demand and storage information.

With that, that completes the demand section.

CHAIRMAN WOOD: "Transparency" means what to you?

MR. CHAPPELLE: I invite a number of people to comment on that.

CHAIRMAN WOOD: To you-all.

(Laughter.)

MR. CHAPPELLE: Transparency being able to see the price, be able to understand the dynamics behind that, to -- for example, in the power market, you understand what you're going to see, what your price is for electricity, so you can make a decision on natural gas purchases, oil or coal versus the lack of transparency in an industrial setting where you don't necessarily know what that price is.

MR. BARNETT: Seeing it and believing it.

MR. PINKSTON: Not to argue with the conclusion, but what's the basis for the conclusion that liquidity is sufficient? Is that outreach to the industry or talking to people who participated that are out in the market?

MR. CHAPPELLE: I'm trying to find out where that is.

(Slide.)

MR. CHAPPELLE: We make the point that it is sufficient to transact at multiple hubs. Clearly there's been changes outside of some of the major trading hubs. This is based on outreach to many, many players in the market, many of whom were participants in the study.

MR. PARKER: I think that's the answer, is the pipelines move out and kind of create out customers and well, you buy and sell gas, is it liquid enough? The answer, I think, in general is it's certainly not as liquid as it was. It's much more difficult, but there's enough there that I can transact business.

MR. FLANDERS: You didn't mention anything much about hydrogen for any kind of diesel fuel or anything along those lines. How did you treat that issue?

MR. CHAPPELLE: Two questions there, right? Hydrogen is a major part of the chemical industry and it was addressed in there under the feedstock -- or it is addressed within feedstock. Actually, we see quite a bit of hydrogen growth.

Natural gas vehicles, albeit to the rest of the hydrogen link, natural gas vehicles is treated in our study as a subset of the commercial sector. We actually have a discussion of natural gas vehicle usage and the growth in that.

Then, in general, the hydrogen picture for fuel cells and the hydrogen initiative is one that's seen similarly, if analogously, to the methane hydrates we discussed earlier. It has the potential, but current technology would suggest that that would actually increase natural gas demand if we wanted more hydrogen for those sorts of applications because of the current technology, so we didn't actually show additional demand for hydrogen in the study period as a result of any initiatives for natural gas -- I'm sorry, for fuel-cell type vehicles.

MR. MANNING: We didn't show any relief to natural gas demand coming from the hydrogen economy with current technology. We mentioned earlier that we had modeled a carbon case -- carbon reduction case. We actually just did a sensitivity around that and, of course, whatever the outcome it was going to be increased demand for natural gas. So we didn't model the various different scenarios or approaches. So they would be two very current issues that in both cases we saw those as increasing our gas demand and we did not put those in the study.

MR. FLANDERS: Thank you.

CHAIRMAN WOOD: Anybody else?

MR. FLANDERS: We did talk about questions from the floor. Is this the right time for that?

CHAIRMAN WOOD: Any questions from anybody in the audience for our demand panel -- or actually our supply panel, too, is still here.

(No response.)

CHAIRMAN WOOD: Well, if not, we'll take a lunch break -- Yes, Ma'am, I'm sorry.

MS. LANE: My name is Erin Lane. I work with

Cascade Associates. We represent some southern gas companies.

Two of the points that were made were that it's necessary to remove the incentives for inefficient fuel use, and also obvious throughout the presentation that efficiency is highly important. I guess my comment is that nowhere do we address the full fuel cycle and how utilizing gas where it's needed most, at the site of usage, could really reduce a lot of the need and demand for natural gas. And we're basing a lot of this on central station power plants, and that electricity when it comes out of our plugs is 100% efficient and that's not necessarily true. So if we're looking at the whole energy system, we may not need to build as many central power stations. So just something that -- not really a question, just a comment and something that maybe people should think more about.

CHAIRMAN WOOD: Any reactions?

MR. MANNING: Very quickly, as you will see: We actually have now broken out, for instance, cogeneration. So cogeneration, which used to be lost either in industrial or within power, now appears in its own band.

CHAIRMAN WOOD: Is that the other --

MR. MANNING: Not the other one, the charts. When you look at the power generation suite, you actually saw a cross-hatched section between industrial -- so certainly we do address combined heat and power technology. Within that, we've also, as you saw, been very aggressive in terms of renewables. I don't think this is a study of station power, I think this is a study of gas use and we have recognized in there not only that there's been a significant track record of efficiency and conservation in all sectors -- perhaps no more so than in the power and industrial sector with the use of cogeneration and combined heat and power technology -- but also, of course, we have continued to model that forward.

Keith, anything in addition?

MR. BARNETT: In the detailed report, we in fact are going to address distributed generation and some of the issues, impediments, and opportunities that exist there. Simply put, for this type of study given the model capabilities and the analytical framework, it would have been presumptuous of us to have tasked a future that had large amounts of distributed generation when it hasn't proven itself in the marketplace today beyond what it's done.

So we've projected out trends. We have a 20-something year study -- it's very difficult to justify step function changes in behavior in the marketplace. That was why we approached it that way. We are going to touch on it. I don't even think they advised us of the real work addressing it. We're going to touch on it in the detailed report so people are aware it's out there. It's an issue and it continues to percolate. And it will have its day in the sun, so to speak.

MS. GIACHANI: Pat Giachani with the Natural Gas Supply Association. We just want to highlight one of the recommendations made this morning on the supply panel.

We're supportive of all of the recommendations that have been made in conjunction with the NPC report, but the issue of gas interchangeability standards and the need to re-examine that, we think that's very important and something that the Commission should be paying particularly close attention to, not only just for LNG but for all supply, so we have a greater diversity of supply in the U.S. We also think that working with the industry -- every segment of the industry on that issue is very important.

Thank you.

MR. LUCIERA: James Luciera with the Prudential Equity Group. I do research into the economics of regulation. I'm really kind of an interloper here, I'm not an energy person, I'm a recovering tax wonk. One thing I've been doing a lot of work on is the impact of tax considerations on energy infrastructure, particularly pipelines and power industry assets, which tend to have very long depreciation periods.

One of the things I seem to be noticing is that changing depreciation rules and other tax changes could significantly impact the economics of new investment, not only in generation capability but in transmission and new alternative technologies.

To what extent did you look at possible tax implications or tax impacts on your economic inputs and, if after-tax treatment of assets were to change, would that improve or create more flexibility or something like that?

MR. PARKER: I'll respond from the T&D side, although we haven't presented anything yet. I think we focused more on the barriers to getting projects done, to moving forward and building this infrastructure versus trying to tweak the returns slightly here or there. We felt there was more of a focus needed on what gets you to the first step to actually build this infrastructure and get it done. So that's what you see more of our focus on versus tweaking depreciation or some other factor that goes to the underlying economics.

MR. BARNETT: In the power area I had one of our planning experts chase that. I'm not as familiar with it as he is, but we certainly looked at the return on equity assumptions as it related to the different technologies. We didn't use the same return on equity for every technology. We also looked at the life of the project. We looked at tax issues. He actually calls DEA to slightly modify an approach they had for our purposes that would conform more to how utilities and IPPs look at those investment decisions. So we had a fairly fulsome treatment of it.

The expert that did that is not here. To more fully describe it, in our report it goes into exhaustive detail actually on that.

MR. LUCIERA: That would be the report of the supply group.

MR. BARNETT: I'm sorry, the power area.

MS. LEWIS: Jean Lewis with the American Gas Association. I just wanted to echo the comments of the Natural Gas Supply Association and let you know that the noise level surrounding the full spectrum of gas quality issues is not just LNG and it's certainly increased in recent years. And it's increasing daily. So I wanted to encourage an industry-wide approach to addressing gas quality issues and also let you know that this morning's discussions merely headed up the complexity behind the issues of gas quality.

Thank you.

CHAIRMAN WOOD: We like complex issues at this place.

(Laughter.)

MR. WILSON: James Wilson with Law and Economics Consulting Group, LECG. I just want to make a few comments about the modeling. I probably share the sentiments of everybody else here in wanting to commend the group for putting together so much good information on this important issue. I'm going to criticize one aspect of the modeling; I don't think the group is opposing any policy recommendations, I just wanted to call attention to one aspect.

To greatly simplify what you've done is you have two scenarios: reactive path and balanced path. And looking at your price diagram, I'd like to sort of call one of them the $6 scenario and one of them the $4 scenario. Behind that, I think that the fundamental study approach was to say that policy affects supply and demand and supply and demand affect price. I think we all agree with that as far as it goes. But I think you've missed that price feeds back on supply and demand through markets. Which, of course, is this Commission, one of their primary efforts. And I'd also mention the trillion dollar number didn't come up yet. But this afternoon, later in the slides, that $2 price difference times about 25 TCF a year times 20 years gives an estimated one trillion dollar difference for consumers.

There's a number of ways I think those two paths don't reflect the fact that $6 gas is going to feed back on supply and demand. I think it was clear from the presentations this morning that for the most part the groups were asking what is the policy effect on the two different paths and not what would $6 gas or $4 gas mean. So to look at LNG as one example under the balanced path, the whole process, including permitting, takes five years. You have 15 BCF per day of LNG in 2025 on the reactive path with $6, instead of $4 gas; permitting adds another year of that and you actually end up with less LNG.

Perhaps the integrated report will explain that better. But I had a little trouble with that. It was mentioned in the power sector under the balanced future scenario. You actually used less gas. Again, that's $6 gas and you-all's price assumption, as I understand, is $20, with gas prices that high above oil, I think you're going to see some feedback of that price in the results. Similarly, you have twice as much renewables at $4 as you have with $6.

My point is I think the last 25 years have shown that markets really respond to prices, they respond to policy, but that's a lot harder. But I think you're exaggerating the potential impact of policy on these markets and not fully appreciating the impact of prices.

Thank you.

MR. PARKER: In response, Mr. Chairman, I would say that one of the things this whole team tried to do is we believe there can be differences as you look at the data; there's no doubt about that. So as we publish the details behind this report, I think anyone -- you and anyone in the audience and in America -- can look at this thing and make their own assumptions and build up their own cases and I think that's one of the benefits of this study.

MR. SIKKEL: Just one related comment. I think certainly the one slide I showed, the price responsiveness of North American Supply, I think is indicative of where price gets built in. And I certainly agree with the point that the logic of more LNG in a lower-price environment is something you've got to think about. But certainly the recycle on that was the point, that that price might well still be sufficient to bring forward that supply if the policies were there that would allow that to happen. That's just another point of that LNG area.

MR. MANNING: If I could just add briefly, Mr. Chairman, I think it's a very real issue that we've been trying to address in terms of the dependence within the industrial and the power sectors on natural gas and the lack of ability to use other than natural gas. That, of course, bodes against the immediate market impacts of price. So we definitely have had this conversation. We are mindful of it and we think this is a very significant issue.

MR. FLANDERS: Is the 5- and 10% fuel switchability or interchangeability, what does that assume with regard to high prices and what investment opportunities -- investments in alternate fuel capability that that might bring forth?

MS. WIGGINS: I don't think that number really assumes any sort of future investment. It was something that we struggled with and we discussed as to, if we had sustained higher natural gas prices for a significant period of time, would industrials make the decisions to go out and invest in whatever it took to have an alternative fuel capability. This list is sort of taking it as it is right now. As I said, we did have discussions about what might happen in the future. We frankly just couldn't come up with a way to model that in any sort of robust fashion, so we just took it at the baseline that we have now, recognizing that that is a possibility in the future that people would make those investment decisions.

MR. BARNETT: Our marketing people trot me out to various industrials occasionally. I don't know why, but they do so I chat with them. And I'm not going to use their names, but one of the larger manufacturing companies in this country, I met with their senior fuel executive and some of their lawyers and I asked them point blank about their fuel switching capability. The response is they're getting rid of it in places where they think they can always get gas; they're keeping it in places where they're fearful that at some point they may get interrupted on gas due to pipeline capacity issues and other issues surrounding end use customers and those sorts of things.

But they don't believe they can maintain the dual capability in the face of environmental review and societal pressures. It's a small enough piece of the cost of their product that they're willing to retarget that and try to buy the gas as they need it.

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CHAIRMAN WOOD: That means it's time for lunch. We'll meet back here in about three quarters of an hour. We'll start off with the infrastructure panel and I'd like to invite our guests to come up to the 11th floor.

(Whereupon, at 1:15 p.m., the meeting was recessed, to reconvene at 2:10 p.m., this same day.)

A F T E R N O O N   S E S S I O N

(2:10 p.m.)

CHAIRMAN WOOD: I'd like to welcome everybody back.

Our third panel today is the outlook for infrastructure. We've got a good two-hour slot allocated to that. I will turn it over to Scott Parker and Scott, let you introduce the rest of your panel and jump right in.

MR. PARKER: Thank you, Mr. Chairman.

I have Mark Maassel next to me here. He's with NYSOURCE. He'll be covering the distribution side of our presentation. Ron Brown is next to me here. He's moved up to the table because, Mr. Chairman, he did the majority of the work and, in case I get any tough questions, I need him sitting next to me.

We then have Rick Daniels with NCANA who will be covering the storage portion of our presentation.

Finally we have Byron Wright with El Paso Pipelines covering the transmission side of our presentation.

Having said, that --

(Slide.)

MR. PARKER: -- we just wanted to start out like the others, just covering a little bit about the participation we had and the T&D group -- again, that's pipeline distribution, LDC type loads and storage. That was our task in this, to cover those pieces. We had broken it up along those same lines with participation of many of the interstate pipelines, many of the producers, many storage operators and not only entities and companies from the United States, but also from Canada. We thought it was important to get as wide a breadth of knowledge as we could to move forward on this.

Before I turn it over to Byron, let me just say, when we talk about permitting review and some of the things we'll hear to day, we're going to try to be as specific as we can as to what we think FERC can do with the industry about that.

We appreciate your questions and will try to work through that. It's easy to come in here and complain and say we need something better, we need more. We'll also hear us say we think you've done an excellent job over the last few years permitting projects. As we did some analysis work as to timing on permitting you can see there's been a dramatic improvement over the last few years. We appreciate that. Of course, you know, we're going to come in here to ask for some more support and help. We're going to work with you on that.

You're going to hear us talk about regulatory certainty. You're going to hear us talk about contracting practices on pipelines and storage. You're going to hear us talk about the unique issues that distribution companies face going forward in the future.

Given those highlights, we'll try to drill down in that and what we think FERC can do for us.

Somebody stole my slide. That means I need to turn it over to Byron to cover the transmission portion.

(Slide.)

MR. WRIGHT: Thank you, Scott. I was already in control.

(Laughter.)

(Slide.)

MR. WRIGHT: I guess one of the good things about working in the transmission sector is there's a lot of great publicly available data on the capabilities and costs associated with the transmission sector. The real challenge was getting it put together in a format that we could use to really model what was going on in the world as a whole. We used a nodal simulation model, the structure which is shown on this map, that tried to capture the way the transmission system should work. Each line between any two nodes has data associated with current capacity, cross data to operate it as well as the costs it would take to expand that link.

The model, when it is solved, will determine the flows between nodes based on the supplies and the demands that go into the model by node. It uses existing capacities first to try to reach a solution and then it builds additional capacity as needed to meet the market needs.

(Slide.)

MR. WRIGHT: This next slide is a picture of the transmission system in the United States and the rest of North America. Just a note about it, it is the result of 70 plus years of investment. It is flexible, it is extensive, it's got a great deal of capability -- over 300,000 miles of pipeline facilities, over 19 million horsepower compression. One of the things we came to face again as we came through this, is the age of the facilities. Over 88 percent of the pipeline facilities were installed prior to 1970. Over 52 percent of the 19 million horsepower also was brought prior to 1970, so we're going to need increasing capital expenditures to sustain the safe and reliable operation of that system.

(Slide.)

MR. WRIGHT: This is really a picture of the output of the model aggregated up to a little higher level so it's easier to understand. Just a comment -- we had participants from really all of the major pipelines operations companies in the transmission subgroup. We played around with this model a lot in the sense that we ran lots of different sensitivities through it.

In general it behaved in a way that was quite intuitive to a lot of us. It showed us results that gave us a lot of comfort that, as we went out into the future, it would present a pretty adequate picture of what was going on.

A couple of notes about it, since it is a network model, it rebalances the whole network whenever you change any of the individual statistics. or any of the individual inputs. This is really focusing on the changes and flows that happened between 2003 and 2010 in the model.

Just to highlight a few of the big issues, you can see that we're bringing in an additional BCF production a day from MacKenzie Valley as that production comes down from the Western Canadian sedimentary basin. Those red lines mean decreases in flows. That would indicate the BCF that's coming from the MacKenzie doesn't replace all the decline in native production in Western Canada. In fact, there's a decrease to the west and to the east out of the basin. The two big arrows coming east out of the Rockies would indicate that there is a substantial amount of increased flow from the development of the Rockies gas into both California and the mid continent markets.

The fact that that arrow ends at the mid continent -- instead of markets going into the Midwest indicates that it's really replacing, again, gas that it's depleting out of the currently producing mid continent basin and in a sense refilling the pipes that would otherwise be empty.

Also noteworthy is all those red lines that are coming in from offshore, the 900 million a day in Baja, California, the 700 million a day -- 750 down in Baja, and at the Central Gulf of Mexico, the Bahamas. Those are all inputs associated with LNG inputs.

MR. J. WRIGHT: Could I just ask a quick question about the 2.5 BCF that's coming in through the Gulf that's obviously not flowing into the Northeast because you've got red arrows. Is that just staying home in the Southeast for industrial load, generation load?

MR. WRIGHT: It's replacing decline from the belt to some extent. Also, there is increased load in the area to meet mostly power generation demand in the south central area.

MR. PARKER: Similarly you don't see pipelines being built away from the mid continent or the Rockies coming in simply because the gas is flowing on existing lines replacing declines.

MR. WRIGHT: I'd encourage you to kind of keep your finger on this page. We have a capacity match in a few slides and you will be able to see where capacity is getting built. That's not all the same places that flows happen either.

(Slide.)

MR. WRIGHT: This is a cut at what the capital requirements are going to be for the industry. It's going to average over $8 billion a year between transmission storage and distribution. One of the key things our study revealed to us, you can see in the green wedges on those charts, which is the new infrastructure relative to the gold wedge, which is the sustaining capital. Gold is increasing in share as it goes through time. We're having to spend more and more money on just maintaining the existing capital.

The final color up there is blue, and we show that separately just because it's such a large and singular project on its own.

That gets to our recommendation which is that federal and state regulators should provide regulatory certainty by maintaining a consistent cost recovery and contract environment to allow the industry to make the necessary investments.

MR. CHRISTIN: Why does it decline until about 2007 and then there's a peak up through about 2012 then goes down again?

MR. WRIGHT: That gets to how the model actually adds capacity. In the first few years that may actually be a reflection of, well, in the first five years, we did not let the model determine what capacity got added. We felt that, as practitioners in the industry, we had a good handle on what was likely to happen. Just because if a project isn't announced by now and we don't have at least a few of us that think it's likely to happen, it's very unlikely to happen within the next five years that it will get constructed and put in place. For the first five years that's really a reflection of our kind of industry analysis of what projects are likely to get constructed on the new infrastructure piece.

From there on out, it is really largely capital being invested and major new infrastructure is being largely driven by the need to attach new supplies to the existing network.

VOICE: In that time frame, there's a lot of Rockies pipeline being built.

(Slide.)

MR. WRIGHT: I would just call attention to those who had this in hard copy for years in the bar charts, 1998, associated with the green and 2002 associated with the blue, bars, didn't come out in at least the hard copies I saw. But that's what they represent.

The takeaway is that, back in 1998, contracts were split about 50-50 on interstate pipelines. About 50 percent of the contracts were five years and longer and 50 percent were shorter than five years. This is data that's really accumulated straight out of the public information in terms of the contracts that are posted by the different pipelines on their websites. And in 2002 that had deteriorated at least from the pipelines' point of view to the point where it's really about 35-65, longer than five year contracts, shorter than five year contracts. I would suggest that, anecdotal that understates the impact on the transmission industry because it did not capture the fact that many contracts are renewed now for shorter hauls, as opposed to the soup to nuts wellhead to delivery point hauls that contracts traditionally were.

The finding has been that there have been regulatory barriers over the last five to ten years that have played a part in that change and they can continue to impair investment in the infrastructure.

Our recommendation is that policies should address those barriers, especially in regard to contract entities providing services to human needs customers.

MR. MURRELL: Brian, before you move on, could you just describe briefly if any of those barriers are in your committee's opinion, issues FERC needs to address?

MR. WRIGHT: It's probably no surprise to you that one of our views was that one of the biggest hurdles was the road for term caps. In the recent action associated with lifting the five year term on ROFRs, our view is that most of the remaining impediments are really at the state level regarding LDC's capabilities to contract for longer term contracts.

We did not want to take a position on what the right number was, although I personally might like 20 years.

(Laughter.)

MR> WRIGHT: We thought, you know, our view is, the market really ought to be allowed to determine that on the basis of prudent considerations on each individual corporation's point of view as opposed to a fiat from a regulatory.

MR. PARKER: I would just add that that's absolutely right. Those contract terms with LDCs really is a state issue as to prudence and we're okay with that.

What we're concerned about from the FERC standpoint -- that's why we're here today -- is that, when we do long term contracts, be they 10, 15, 20, whatever they are, that both the customers and the pipelines want to be assured when they make these financial investments from both sides, that the rules don't change midstream.

So when we talk about long term contracting, we kind of couple that with regulatory certainty and that's the certainty that the deal I struck today that met the regulatory requirements of today doesn't change three or five or seven years out and totally change the fundamental underlying principles I had to invest in this $8 billion a year to build this infrastructure.

I would point more towards that and say let these contracts that are built and fundamentally underlie new construction and enhancement of our system, those long terms contracts, both from our standpoint and our customers' standpoint, need to be maintained over the long term.

MR. FLANDERS: Are there a number of factors other than regulatory policies which influence the term in which parties enter into contracts? Market factors for instance?

MR. WRIGHT: Absolutely. That's one of the reasons we couldn't arm wrestle ourselves to a conclusion as to what the NPC was going to recommend as the right contract. What we could agree on was that there were regulatory barriers and that the market would be better if they weren't there.

MR. PARKER: In the detailed write up, we actually go through and kind of just back up in history a little bit and we say, okay kind of, let's roll through history and how this contracting has evolved. Marketers came on the scene, they began holding capacity, LDCs started buying more at the city gate. We do walk through that. I think where we got through as a group at the NPC study is -- Mark will talk a little bit about that when he goes to the distribution side.

If there are barriers for the distribution companies in the new world as we stand today to take long term contracts, they would do that. They fundamentally would say, I want to do that but they won't do that because there are barriers. Those are what we need to address.

Also, again that regulatory certainty in all parties point that those contracts are going to be available.

MR. MAASSEL: Let me just second what Scott said from a distribution company standpoint. The issue is not that we want somebody to mandate them. We have to have long term contracts. We want that capability. It does make sense. You're exactly right. There's a lot of factors that go into that decision but when it does make sense it is important for us to have the flexibility to look at long term contracts and be able to sign up as needed to serve our customers.

Again, where there are barriers that say one of the things you cannot do is have a long term contract, we'd like to see that barrier removed.

MR. WRIGHT: Just one more thing. Human needs customers at the end are not just LDCs that are providing gas service to human needs customers. It also extends to, for instance, power generators that may use gas to generate power required for human needs customers. To the extent there is regulatory barriers that preclude power generators from recovering prudent levels of firm contracts because of some mandated structure in the pricing of the power pool, we'd like to see that removed as well.

MR. MANNING: Mr. Chairman, I think it's also important to note that we're raising certain issues. I think that there's some consensus on all of this material but I think what we're trying to do here is raise issues as much as offer findings. I feel compelled to intervene with respect to the demand end of the equation. There isn't always consensus on each of these issues.

MR. SCOTT: I think it's important to note in term caps, for instance, or the MPC themselves, that's not an advocacy piece. I think it's important that these issues provide analysis. But it's not every case that we have consensus on these issues.

MR. WRIGHT: Just in that vein, are you raising the issue that you'd like to see hourly rates as a standard for power providers? For power producers? That's what it sounds like you're leading to.

MR. J. WRIGHT: We have a recommendation. It doesn't address our hourly rates in particular but it that

FERC should allow operators to configure transportation and storage infrastructure to meet whatever the changing market needs are.

MR. WRIGHT: The slide show that 1998 represents a much bigger chunk of total contact. People who have expanded are the power marketing people, the customers who are now of course somewhat challenged as regard to bankruptcy and credit issues.

But the other key thing is that there are different customers and we need to be able to structure terraced services that allow us to meet their needs.

MR. J. WRIGHT: So instead of negotiated rates per se, you'd like to see negotiated terms and services as well?

MR. WRIGHT: The NPC did not take a position on negotiated terms and services. It took a position on we should be able to put tariff services in place that will allow us to meet the needs of those customers classes.

MR. MAASSEL: Let me suggest -- I suspect you are aware that LDCs and pipelines sometimes have slightly different views on this.

(Laughter.)

Mr. MAASSEL: Sorry, we are very supportive of these ideas but we need to look at the options. We need to understand what kind of new products and services take place in the marketplace today. As we get into some of my materials, I'll come back to this exact recommendation and touch a little bit on the fact that there are some very serious issues. The NPC does not take a position on what kinds of products out to be out there, how they ought to be structured, when they should be used, and there are a whole panoply of issues but I think we do recognize that these are important issues that need to be addressed.

CHAIRMAN WOOD: For this to be made into a recommendation obviously there's something out there. Can you all give me some examples where FERC has not bee as receptive of these type of configuration for customers?

MR. PARKER: I guess I'll steal somebody else's thunder. We'll talk about the storage. We haven't gotten there yet but what we've seen in some cases are where companies come in to do maybe a storage expansion and there's a vary detailed look at -- okay, you need 10 injection wells, but you can only use eight of them for withdrawal because that's the way the model worked out.

What we would say under this one is, why don't we figure out a way to use 10 injection wells and 10 withdrawal? A very specific example, Mr. Chairman, because you asked for one. Let's build that flexibility into there since we've got to spend the money to put the wells in anyway. That's what we say, let's look at anything we do in the future we need the flexibility on storage to serve the new markets, our generation markets as they come on. let's look at those, pull up those specific examples and talk about some flexibility that all parties in the industry can climb on board and say, well, there's an investment being made anyway. Let's build that flexibility into the whole system.

MR. BROWN: Another example is with horsepower. If you can put a little bit of extra horsepower in, you can do a little bit more on an hourly basis but if you put more in, then you're building determinate is made on a higher volume. You get no benefit out of the flexibility. It's stricken away from you. Your rates are lower then it's hard to get returns. So if we can be more flexible on the facilities where we can do more hourly. As we go to a power market then we'll be more and more hourly stretched on pipelines. That's another example.

CHAIRMAN WOOD: Thank you.

(Slide.)

MR. WRIGHT: The next slide is our picture of expected changes in pipeline capacity between 2003 and 2010. Again, aggravated up to a higher level to kind of cut out a lot of those small changes that are going on. Almost 2.5 million horsepower compression will be required.

Again, you can see the capacity associated with the MacKenzie Valley gas coming down into western Canada. There will be pipes basically able to meet all those needs.

Similarly, gas coming out of the Rockies coming to the mid continent and going to the the California markets without any real capacity needs. Much of the growth and demand in the Northeast is expected to be met either by increasing volumes coming out of the maritimes or LNG imports. There'll be a substantial amount of transportation capacity added really from storage areas into the market place to provide essentially the seasonal peaking needs of those markets.

MR. MORRELL: Mr Wright, before you move from this slide, I'm a little confused about what this slide is showing compared to the ones we had a few slides ago that had reduction in the mid continent as well.

MR. WRIGHT: These were capacity capabilities, the other was flows. And actually this is changes in capacity. The other was changes in flows.

So the red lines would indicate a decreasing flow through a particular existing set of pipelines.

(Slide.)

MR. WRIGHT: The next slide looks at capacity additions in the network from 2011 through 2025. 57.5 thousand miles of pipeline, 7 million horsepower of compression added. A big chunk of that is associated with bringing the 4 BCF a day of incremental Alaska supply into the marketplace, bringing that to western Canada. There will be some incremental needs on the existing pipeline system to bring that gas to market capacity wise.

Just exactly how much that is going to be, and that's why you've got a range there between 500 and 2 BCF a day depends on the rate of decline in western Canada and the rate of increase in demand associated with heavy oil or tar sands production in western Canada. It's a pretty finely tuned balance.

And the recommendation is something we've touched on already. Local, state -- I'm sorry, this is a new one. Local, state and federal permit reviews of major infrastructure projects should occur within one year -- a one year period using a joint agency review process.

What that's getting to is that the Commission, and I'm measuring this since we, I think, asked for something very similar to this in the 1999 MPC study, has made substantial progress in terms of getting the reviews out within the four walls of the Commission.

Our point here is that there are substantial other agencies that need to review and essentially pass on certificates before we can go to construction on them.

What we're asking for here is some sort of joint process that doesn't preclude anybody from having their say but allows them to have it said all at once without having multiple proceedings where we have to produce the same documents or data three or four times to different agencies at their own time frame and at their leisure.

MR. WRIGHT: Is this something above and beyond the coop agreement that we have with about ten other agencies now? Are you looking for even more cooperation than you have? That's what you're attempting to get now?

MR. BROWN: Yes. This is just expanding upon that. Coastal zone management, for example, once it clears FERC, you can expect that you go to work, but because of the Coastal zone management or the Corps of Engineers, or any other agency that then stops the project, we wanted to be a joint agency review for the coastal zone management, the Corps of Engineers, anybody that has input, puts it into the project during this 12-month period.

Once FERC issues the certificate, that's it. I mean, we're not saying that you can't challenge something in court, but we don't want agencies that should have been part of the joint agency review, then stopping the project from going forward after the fact, after a FERC certificate has been issued.

(Slide.)

MR. WRIGHT: Just to close out the transmission section, we did a number of sensitivity analyses on the system, two of which we thought would be of particular interest. We spent a lot of time talking about LNG terminals earlier today.

We looked at what if the siting problems associated with LNG terminals were just insurmountable and we really couldn't locate any on the East Coast, and, instead, had to locate them on the Gulf Coast, which, while it may be more amenable to facilities such as this, it's farther away from where the markets are.

That line tracks the expected impact on price associated with having the pipelines get more full, and, in addition, there's probably some construction needed downstream in the industry to get the gas finally delivered to where it needs to be.

By 2025, we'd have an average annual impact on price of 40 cents a decatherm, incremental, by not allowing us to locate those LNG facilities much closer to the market area, like we assumed in the study.

MR. BROWN: Excuse me a minute. That is an average annual, but because you're using the pipes to a lot higher degree, you'd have a lot more volatility as well.

MR. WRIGHT: The volatility, we've examined some of the weather sensitivity. Early in the demand section, Hal talked about one of our assumptions was 30-year normal weather.

We used that throughout the study as a basis for the reactive path and the balanced future cases. We all knew that's not going to happen, so we actually were able to go back and look at 70-plus years of weather and select the

25-year period that had the most heating-degree days and the 25-year period that had the last heating-degree days.

These are simulations, but they use actual weather patterns that have happened in the past. We applied them to the system to see what the impact would be.

We took the dates off here because that's not really what we're trying to talk about in terms of when any specific year happened. What we wanted to do was to establish the range.

In any given year, the weather could impact the price between $1 and $1.50, more or less than it would otherwise be on any kind of straight-line basis. So it's much more difficult to see what the trend is when you can't see beyond the weather.

With that, I'll turn it over to Mark Maassel.

MR. MAASSEL: Thank you, Byron.

(Slide.)

MR. MAASSEL: I'd like to spend a little bit of time talking about the distribution side of things. As was pointed out earlier, a lot of the things I will touch on here are actually state regulatory issues, not FERC issues.

But for the sake of completeness and the sake of just making sure that all the issues are on the table, we thought we'd walk through the discussions. The distinction I'll be making, largely follows the FERC jurisdictional guidelines, versus those areas that are regulated by something more local.

When I say "something more local," we did not distinguish in this study between municipal-regulated, state-regulated, investor-owned, owned by municipality. The issues we considered were really whatever entity it is that happened to get the gas at the city gate and bring it to an end-use customer.

Again, I will loosely say LDC. I'm sure that throughout this presentation, it's what I'm used to, but if you'll keep in mind that it does include municipalities and other forms of people bringing that gas to the end-use customer.

(Slide.)

MR. MAASSEL: Let me back up and tough on some of the things that David Manning and his team brought forward, just in terms of looking at how we assessed the growth and the impacts needed on the distribution infrastructure.

The key to the expansion of our system is really driven by demographic trends. It is the growth in population, and there is this continuing shift where there's more residential growth in the southern parts of the nation versus northern. That's all built into the analysis work David did.

From our viewpoint, the critical issues were that the number of residential customers expanded from roughly 61 million to roughly 81 million over the course of this study. There were also expansions in the customer areas all served by this group of distribution type companies.

The demand group had taken a hard look at the impacts of energy efficiency and conservation, both of which are critical to us and are very important to our customers. We see those trends continuing, and the impacts on those facilities that we need to build, are built right into this analysis, again, by using historic data for costing and sizing and names and other issues. That information is built right into this information.

The costs do vary widely, as you look at the type of work you're trying to accomplish, the area of the country you're trying to accomplish it in. Again, we simply took all of that data, accumulated it from across the industry, made sure we did some benchmarking to check the validity of the information, and put it together into the model that we actually ran.

The model that is used to look at the expansion of the distribution system is a post-processor model, in other words, it happens after the major run that takes the supply and demand, matches them up. We take the information at the end and put it into our model, take a look at how the distribution grows.

We did assume O&M costs throughout this entire period, and the life of the facilities that are constructed, exceeds 25 years. Noting that's built during the study is replaced during the study, however, of course, you've got facilities that have been in the ground for a long time.

Those facilities do require maintenance going forward, and those costs are built into this. Finally, we did make an assumption about improvements in productivity, which are large and technology-driven, and I'll touch on them going forward.

(Slide.)

MR. MAASSEL: You've seen this chart before. Roughly $135 billion have been spent to expand nationwide infrastructure. From an LDC standpoint, it's roughly $4.8 billion a year, just a little bit less than that. That's just slightly less than the historic average for the last ten years.

The number does not change, particularly as you look at the reactive path versus the balanced future, simply because while residential in the balanced future is slightly less gas consumption than in the reactive path, the reverse is true on the commercial side. Again, you heard that explained earlier.

Because of the lower prices in the balanced future, there's actually more commercial activity in that case than what you see in the reactive path. Again, from a distribution standpoint, the expansion of our systems look very much like this.

The one place we used the definition slightly differently than what I talked about a minute ago, is in looking at the costs for maintaining our system. The Pipeline Safety Act has impacted distribution companies as well, because the Department of Transportation definition brings some of our facilities into that Act, and we need to meet those requirements.

As a matter of fact, it's something on the order of 22,000 miles of distribution company piping that is actually classified as transmission for purposes of the Pipeline Safety Act and compliance with that Act. That leads us to something in the neighborhood of the $2.7 to $4.7 billion in costs you see shown on this slide, and those costs were also added into this.

One thing we have not added into this from a cost perspective, is anything related to security of our facilities. If there is something that comes along in the way of terrorism and other issues, those costs are not built into this.

You can look at all of this information and I can tell you that I don't see anything here that suggests that we can't accomplish these kinds of expansions going forward.

In fact, with good regulatory policy and with good financial climates, these are all achievable kinds of investments.

(Slide.)

MR. MAASSEL: There are some challenges. I'd like to touch quickly on them. They are similar to what we were just talking about.

At the transmission level, there are siting issues on an individual state basis. In some cases, for some larger projects where we get involved with there will be a great value to creating something akin to the joint agency review process we just talked about. Again, it would be done on the state level.

There is a model put together by NERUC and the IOGCC that strikes me as a good thing to look at for people considering how we would really put this thing together. The need for capital will be important, going forward.

One of the very significant changes that we see right now is a different use for the funds that are generated by distribution companies. Throughout the '90s, the majority of expansions of distribution company systems were done from internally generated funds.

One of the very significant changes that we now deal with in this marketplace is the fact that the price of gas has gone up. And as we fill the storage field to serve customers in the wintertime, a lot of our cash is being tied up, if you will, with the inventory.

By putting that gas in storage, what that really says is that we are likely in the future to face the need to go out into the financial markets more than what we have been required to do perhaps in the last ten years.

To do that, we need to be very strong as an investment entity. To give you a feel for the size of this industry, if you took the roughly 200 distribution companies that are members of the American Gas Association, took their market capitalization, it's less than General Electric, so this industry needs people to really pay attention, have stable regulatory policies, really watch what it is that is happening, so that we are able to compete in that kind of a capital marketplace.

The reliable gas service is an issue we touched on earlier. We do recognize, as we talked about when Byron was presenting, there is a need to look at new kinds of services to meet the changing demands of the various customers, no only of electric power generators, but also distribution companies and others.

However, that's an issue that takes an awful lot of careful thought, because new products can in some cases, impact the LDCs, so some of our traditional purchases, some of our traditional responsibilities to serve that human needs customer.

There's been a process put together, agreed to by the PGA. A letter was directed to you earlier this year, Mr. Chairman, indicating that through that framework, we're going to sit with our brothers in the pipeline industry and try to work together through some of these issues and see if we can't draft some answers.

The NPC was able to go a little further than that. We just wanted to raise it as an important issue and say that we at least had a framework for that.

The other thing I'd like to touch on is this conflict, if you will, the tension between revenues and capital requirements. Again, energy efficiency is absolutely critical to this industry. It's important to our customers. It's important as we move forward in terms of balance of supply and demand that has somewhat unintended impact of an impact on the distribution companies' revenues.

There are some very novel approaches to dealing with that issue. The state of Oregon came out with a very innovative tariff structure that we believe addresses this issue very directly as we move forward, and we see increased efficiency levels driven by the marketplace.

Those kinds of options will need to be considered and thought through in the various cases and in the various states. It's termed conservation tariff. What they really did was tie their revenue to sort of a projected, if you will, consumption by customer use, per customer.

Even as that usage shrinks, the revenues are able to be maintained so that they can do the kinds of things they need to do to maintain their systems, provide the quality service to customers.

(Slide.)

MR. MAASSEL: We touched on the fact that there is a one-percent improvement in cost of installing distribution facilities, and that's really driven by enhancements in productivity. The enhancements in productivity through the '90s, averaged something more than two percent.

However, at this point, it's probably unlikely that we'll be able to continue as an industry, all of the staffing level changes that occurred in the past. Instead, we need to rely much more on the technology innovations going forward.

The concern we have at this point is that the funding mechanism historically used for research is disappearing. For us, there is a need to move forward with something to replace that, recognizing that the benefits to customers from safety, from improved techniques, for replacing and installing pipe, for locating the installed facilities, whether they are ours or another utility's underground, and, frankly, for dealing with environmental remediation. Those are some of examples of areas where customers benefit through the development of technologies.

The recommendation is then that regulators should, in fact, encourage collaborative research among utilities and others to develop more efficient and less expensive infrastructure options. This is an area where DOE has done some work. It's not a significant amount of work, and we think that it really is important that the industry continue to be a part of these types of options.

In the study, what you see is that this leads to an estimated $300-400 million a year savings for customers as we move through time and become something that's truly significant in terms of the industry.

(Slide.)

MR. MAASSEL: The final slide I'd like touch on, really takes us back to one thing that we were talking about earlier. It's the expiration of contracts. I'd like to simply point out that the issues related to this are many and complex.

The ROFR issue is certainly something that we as LDCs have some concerns with, and we feel needs to be dealt with. But at the fundamental level, again, as I stated earlier, we need to take a look at more at the state level than here, to have the flexibility on the long-term contract. It make sense to make sure that we actually have the capability to go out and sign that contract, to make sure that we are able to deliver the gas to our customers.

This will also join, I suspect, at some point, with the idea of how long is that contract in terms of the length of the pipe? In recent history, LDCs have tended to move closer and closer to the city gate. There will be firm contracts from their city gate back to the first liquid point in the marketplace. It may not go back any farther than that, and there may be a question that we may need to address in the future that says do we need to begin the way we did historically, going all the way back to supply basis in order to be sure that we have supplies for our customers in wintertime.

Those were all issues that are in front of us. Again, the recommendation is the same that you saw a minute ago. This slide is identical to the one Byron shared with you.

MR. CUPINA: What's the trend on retail unbundling? For a few years, there was more and more unbundling and now there aren't such increases. Do you see us going back to rebundling?

MR. MAASSEL: I don't think we're going back to rebundling. I think it has reached a plateau. Much of the reason that the states have adopted policies on pipeline capacity -- what's the role of the LDC? Does someone else step in and become the supplier of last resort? Who is the one who really needs to have the capacity?

I think the issue at the state level is, we need to have an entity clearly identified that it's your responsibility to make sure those pipeline contracts are in place. Let's make sure that the customers in the state do not end up without gas.

I'm sure, at this point we're speaking more about that human needs customer. Certainly, the types of customers that we deal with on a routine basis, have purchasing capabilities far beyond anything that would require a utility to be involved. They don't want us there.

(Slide.)

MR. DANIEL: Thank you. Natural gas storage is a very small part of the natural gas industry in terms of capital, employed in terms of people. But it is a very large part of the flexibility of the industry. That's really why we're devoting as much time as we are here to gas storage.

A very large component of the physical flexibility of the gas industry to meet both highly variable demand and match it against fairly constant supply, is really the role of gas storage.

I'm going to talk very briefly about the storage task force in doing their work, and a bit of time talking about the changing nature of demand being put on the storage infrastructure. Some of those trends we see going forward. The bulk of my time I will spend talking about how we went about estimating the quantity of storage capacity that we think will need to be added to meet growing seasonal storage demand over the period.

Also, to talk about that, I will need to spend a little time talking about the very murky issue of how much storage capacity we currently have because it's pretty hard to get a firm starting point in terms of how much we need to add without that.

Also I again will talk briefly about weather sensitivities because gas storage, as I am sure everybody knows, is very strongly affected by weather sensitivity.

(Slide.)

MR. DANIEL: The approach the storage group took is really broken into two parts as shown on this slide. Most of our work and most of what I'm going to talk about here is really trying to come to grips with the estimate of the aggregate North American demand for seasonal storage. We also did some work on trying to do some regional specification on whether the demand for open storage is going to be at some of the regional economics around storage. And I'm not going to spend much time on that. They will be details on a regional nature in the final report.

In terms of the aggregate storage demand the way we went about it is essentially assuming that gas supply in the future is going to be continue to be relatively flat year round as it has been in recent years, because we are going to be, as you heard earlier this morning, in an environment throughout this period where supply is going to be hard pressed to keep place with demand and the gas producers are going to be wanting to keep gas production pretty well at the highest possible levels year round.

Demand, on the other hand, is highly variable and, thanks to some very detailed by the demand group, we have a lot of information on daily and monthly demand trends. That's largely what we used in forecasting the trends in demand for storage. The approach we took is really to look at during the traditional summer period, the seven months from April until October when gas supply typically exceeds demand. Estimating year by year through a forecast period how much excess supply there is that is available to go into storage and then similarly in the winter how much shortfall and supply there is to calculate each year of the forecast period essentially how much gas you need to put in during the summer to meet the extra demand in the winter.

Actually, those numbers, when applied backwards to the last few years come pretty close to matching how much gas actually was stored if you look at the bottom and the top of the inventory levels in North America.

On a regional basis we looked at regional storage development costs and regional summer-winter price differentials to try to estimate the economics of where storage ought to be added. The model that was used did give us output on regional development patterns and storage and, as I said, that will all be detailed in the final report.

Just one word of caution. I think the storage group has been looking at those results. This also is reflected in the final report. But we did come to the conclusion that probably the model was trying to build too much storage in market areas, so we don't think we adequately reflected the geological constraints from adding market area storage and that's the direction that more storage would probably have to be built in.

(Slide.)

MR. DANIEL: This chart gives you a picture kind of at the end of the period 2025 of the makeup of the daily demand profile. As you can see, it continues to be highly seasonal. In fact, it becomes more seasonal and more weather sensitive year by ear throughout the period. That's due largely as you heard this morning in the demand presentation, from the fact that residential commercial demand which is highly seasonal, highly weather sensitive, continues to grow quite robustly, as does power demand, which has a significant winter peak as well as a summer peak.

Really, what doesn't grow and even declines slightly is industrial demand, which tends to be flat year round demand. What that means is, the seasonality and weather sensitivity of gas demand increases over this period and, as a result, is going to put more pressure on gas storage.

Also, because of the electric generation load, it amplifies the winter peaks because there's significant power demand peaks in the winter. It also creates a secondary summer peak and that secondary summer peak, as we have seen in recent years now, competes with gas intended for injection into storage or gas supply during those periods.

As a result, storage facilities in the future are going to have to have much higher injection capabilities in the shoulder seasons to compensate for that at higher peak day withdrawal capability both in the peak of the summer and the peak of the winter.

Aside from needing more seasonal storage as you will see in a moment, we would need a different type of storage. High deliverability, more flexibility, more capability responding to day and even inter day demand.

MR. PARKER: The main thing that doesn't jump out at you but I'll add that the study reflected is, because of these higher summer demands the price of gas actually flattens out on an annual basis in the study. So you don't have what you would expect to see nowadays, a high winter price and a low summer price and the high winter price.

The actual price starts to flatten out. You see the same level of pricing throughout the year or closer to the same level of pricing and it is really reflective of these higher summer demands in the model as we move forward.

MR. FLANDERS: What does that do for seasonal arbitrage?

MR. PARKER: NPC isn't a marketeer. They didn't look at what that would mean. But clearly you can make your own withdrawal assumptions by the data. But clearly, there's less of a spread on an average annual basis than you would expect to see from the past.

MR. DANIEL: We had quite a bit of discussion on that issue in the storage subgroup. There are quite a bit of different views on who's going to be contracting for storage and who's going to be using it that will probably impact those pricing trends. The scenario where you have very low summer-winter differentials is probably consistent with one of our major users of storage and the future becoming once again the local distribution companies when they come in and are really filling storage all summer on a relatively price insensitive basis. They would simply meet volume targets by the end of the summer so they prop up gas demand in the summer, equalize it more or less with winter demand, and you have this flattening of prices. They would be under that scenario, the storage customers, if you like, and they'd be contracted for reliability purposes.

Another scenario, and who's to say which of these scenarios might occur, where the major contractors for storage in the future are again the energy merchant companies looking for the seasonal price arbitrage and the amount of gas that needs to be stored simply won't get stored unless those seasonal differentials occur.

In reality, which mix of scenarios? It's difficult to say.

MR. HARVEY: To follow up on that, because it's an important point, it would be required that that be the scenario in effect in order to encourage the development of additional storage, I think.

MR. DANIEL: You could get additional storage under another scenario. You could have all these fees stepping up and contracting for long-term storage capacity to meet their obligations to serve their reliability concerns. That would stimulate storage under the one scenario. Under the other case, it would be more the arbitrage player.

MR. HARVEY: Does the model then shift those costs to residential customers? To commercial customers? Does that follow through, then?

MR. DANIEL: No.

MR. HARVEY: That's a pretty substantial incremental investment targeted to a certain class of customers, so it's kind of non-intuitive to hear that the market driver for this kind of activity isn't really there in this model.

MR. DANIEL: I'll come back to that. That's kind of the state the storage industry is in right now. There is a real transition in terms of who the storage customers are.

MR. HARVEY: Is it fair, then, to say that basically you added storage in order to balance the supply? As you pointed out, supply on the sort of smooth path where wells are fully used pretty much all the time?

MR. DANIEL: That's exactly right. In the end, we looked at the underlying demand as opposed to the price outputs of the model to say somebody, whether it's the LDCs or energy merchants or whomever, for this market to work the way we're projecting, somebody's going to have to store this amount of gas each year. That amount of storage capacity is going to need to be built regardless of who the customers are.

MR. HARVEY: So you cannot kind of solve for it that way? Thank you.

MR. PARKER: Just to clarify, the cost of the development of storage is all bundled into a model and is all rolled through. As you probably didn't say it belongs to this customer or that customers, if the model didn't build the storage then you have to assume it is now building through more pipeline infrastructure to get the deliverability required by the demand group.

The model makes choices by those costs. It clearly would have cost it more to build more pipeline infrastructure than in this case, to build the storage that it built, so it made an economic decision at the lowest cost.

MR. BROWN: But if you don't balance the supply-demand that's storage, then you've got extra pipe which you also have to have extra supply to fill the pipe and then you've got supply that has to be shut in in the off peak.

MR. HARVEY: One of the less expensive ways to deal with that would be this question over here would be some demand response kind of activities which, on a rolled in cost basis would be a lot clearer. But that wasn't sort of modeled as another supplier of this kind of capability.

MR. DANIEL: Actually you do see a little bit of the impact of that on a slide I'll be coming to where we talk about the second case where there is greater energy conservation and efficiency in the residential sector and I will show the degree of impact on the amount of storage required. It does reduce the amount of storage somewhat but not a whole lot.

MR. BROWN: The fuel flexibility and fuel switching capabilities do go a long way to help balance out storage.

MR. HARVEY: Absolutely.

MR. BROWN: Without that being built into the model we would to have had to installed more storage.

MR. HARVEY: Thank you.

(Slide.)

MR. DANIEL: This is the same recommendation we saw with the discussion in the pipeline section. Coming out of this changing nature of demand storage is FERC should allow operators to configure transportation and storage and related tariff services to meet changing market demand profiles. There will probably be a wide variety of solutions proposed by different storage operators and I'm not even going to try to represent those potential solutions here today.

The point is the same as under the pipeline review.

(Slide.)

MR. DANIEL: This chart just basically tries to list various -- where this incremental demand for seasonal storage comes from.

On the left hand chart, the pretty small dotted line shows the total demand for storage on average during the 1999 to 2002 year time period. On average in that period you had to store about 2,269 Bcf per year in order to balance summer and winter demand.

The remaining years are five year increments. Your big blue bar, total demand for seasonal storage, and the big brown of that shows where it comes from, really the residential and commercial sector, the residential shown there in blue, commercial in red, is really what requires that seasonal storage, a small amount for industrial in the gold.

Power generation as you can see actually reduces the amount of seasonal storage required because power generation demand for gas is slightly higher in summer than in winter, so that actually has a small offsetting impact.

But the real driver is the robust residential-commercial demand.

(Slide.)

MR. DANIEL: I mention as we get into this thorny issue of how much storage capacity we currently have, it needs to be addressed very briefly because we're talking about storage needing to grow by the end of this outgrowth period to about an order of 3.3 Tcf of total seasonal capacity.

There is data out there that suggests that we currently have in North America a working gas capacity of over 4.5 Tcf.

The reality is that the effect of storage capacity in North America is clearly much less than that, the maximum amount we've actually cycled in one year.

Going from the bottom level, the lowest inventory level you reach during the year to the highest inventory level is 2.9 Tcf, a far cry from the 4.5 that's made up of about 2.5 Tcf in the United States as shown on the chart on the left there, that's just the U.S. data. But then there's an additional 24 Tcf in Canada.

Juxtaposing those numbers, 4.5 versus 2.9 might suggest there's a lot of unused storage capacity up there. But if you look at the trends over the last few years, it suggests there isn't.

In some years, the existing capacity in fact is pushed pretty much to its limits. Whenever we've tried to cycle close to 2.9 Tcf of gas in a year it has cost some pretty extreme price swings and price volatility.

We illustrate here on this chart by looking at the year 2000 to 2001, which was a fairly extreme year where you went from historically low inventory levels in spring 2001 and built up to some of the highest inventory levels by that fall.

So you push the storage capacity at both ends, we believe, of its capability and as an indication of the fact that you were pushing infrastructure that hard, the red line shows what happens to price in that period when you try draw storage capacity down below the levels that are seen in previous years, you saw NYMEX prices shooting up above $7.00 and Henry Hub spot prices about $10.00 at the end of that winter.

Yet just a few months later as you push the other end of the storage capability and try to put more gas in, like 2.9 Tcf in total, you saw the opposite. Prices fell dramatically and there was production shut in as opposed to earlier in the year when there had actually been short term demand destruction.

Taking it as a given that that degree of price swing in the air is not healthy for the market and causes it to go from demand destruction to supply shut in all within the space of a few months, we're saying. The actual capacity of the storage infrastructure to manage today without that kind of dramatic price swing is probably somewhat less, considerably less than the 2.9 Tcf we estimated it's on the order of 2.6 Tcf is all we've been able to cycle without some pretty significant price swings.

(Slide.)

MR. DANIEL: If we currently have that kind of capability, this is the model results in terms of that analysis of demand for seasonal storage.

It has been on the order of about 2.3 Tcf used over the last few years. The existing capability, if you take the existing capability of 2.6 to 2.7 Tcf as a starting point, you can see the growth from there up to a total of 3.3 Tcf needed at the end of the period, or about 700 Bcf of additional storage capacity would need to be added.

The assumption behind that, though, that is the reactive path case, normal weather, which means every year in the outlook it seemed to have average weather.

(Slide.)

MR. DANIEL: You see a very different picture if you take any one of the weather sensitivities we developed based on historical weather variability, one year being a very cold winter, the next year being a very warm winter, et cetera, and overlay it on that same demand model and take a look at the impact on storage.

What you get is extreme variability in the amount of gas that you would store from summer to winter, from year to year, ranging all the way from as little as two Tcf to up over 3.5 Tcf within the next half dozen or so years, and then going from there towards the end of the outlook period.

This may be the most troubling part of the work we did. It suggests that even in the near term, in a very cold winter, a significantly colder than normal winter would probably stretch existing storage capacity beyond its current capability, keeping in mind that we haven't had a winter like that for quite some time. That is a tentative range from normal to warmer than normal.

A question was asked earlier in terms of the alternatives to storage being some degree of demand response. In both cases, we're trying to improve flexibility of the system, and greater flexibility on the demand side is one way of reducing the need for storage.

Probably the best indication of the effect of that is to look at the balanced future case, which, as you heard earlier today, assumes much more in the way of energy conservation and efficiencies, in particular, in the residential/commercial sector.

(Slide.)

MR. DANIEL: It does reduce the demand for storage on that weather sensitivity case, but it's not as dramatic as you might think. Certainly there is not much reduction at all in the near term. It isn't until later in the outlook period that you see a significant reduction in the amount of storage capacity you need.

Even in that case, the balanced future case, it would suggest that the system is currently vulnerable to a significantly colder than normal winter.

(Slide.)

MR. DANIEL: I would like to conclude by just going over a few points which are some of the challenges currently faced by the natural gas storage inventory, some of which I have already referred to.

Obviously, the need for inventory capability is primary for meeting that potentially colder than average winter, but also to meet the growth in the market; higher peaking capability to meet weather-sensitive demand growth.

The challenge of high cushion gas costs is both a challenge and an opportunity. It's certainly a challenge for new storage development, because with the price of natural gas today, it certainly increases the capital cost of bringing in new storage projects significantly, and as much as half of the cost of some of these storage projects may be the cost of cushion gas.

On the other hand, there's an awful lot of existing storage facilities where there may be a potential to reduce the amount of cushion gas, create additional working gas capacity, and recover gas. That would be the opportunity for the industry.

I mentioned before, the daily volatility of power demand and the pressure that puts on gas storage; also the geological limitations. In many ways, we think the low-hanging fruits have been picked in the gas storage business. A lot of the best reservoirs, the best salt cavern sites, have been developed.

There are certainly more opportunities out there, but we expect the cost of developing storage will continue to rise.

I mentioned also briefly earlier, in response to one of the questions, that it's a bit of a difficult time for the storage industry and the changes that are taking place in the customer base, the recent decline of energy merchant storage customers, recognizing they have been the most rapidly growing segment of the customer base for storage.

Many of them have been relinquishing their storage capacity and downsizing their activity in the storage arbitrage business. Meanwhile, that activity has not really been replaced by any long-term alternative customers.

You certainly see a good likelihood that local distribution companies may need to get back into the business of contracting for storage, but at this point, I can't say that that's happening to any great extent. So, marketing storage capacity right now, despite these very promising long-term fundamentals, is not a very rosy picture.

CHAIRMAN WOOD: Who's doing all the injecting? Every week, we get a nice number at 10:30 on Thursday. Who is doing all of that?

MR. DANIEL: It's the existing storage customers. Most or some of these are contracted on a shorter and shorter-term basis. Certainly, I think the trends that we see, especially early in the summer, a lot of the injection is occurring by local distribution companies who are trying to meet their targets.

This year, in particular, in the early part of the summer, there was almost no summer/winter price differential, so there's very little arbitrage injection going on. So I believe it is mostly the local distribution companies who are keeping the injections up in that period.

In the latter half of the summer, some healthy summer/winter price spreads did develop and probably the arbitrage customers did pick up a piece of the injection.

MR. PARKER: Also, just as a specific year, this study really looks more at the long term, but as you know, we did not have a very hot summer in many parts of the country. A lot of the customers put gas into storage late in the year because of that hot summer not evolving.

MR. DANIEL: So it's also important to keep in mind that most storage remains quite highly regulated.

(Slide.)

MR. DANIEL: I think it's still somewhat less than 15 percent of North American storage capacity is in the category of independent gas storage, the rest of it being storage that is operated either by the pipelines to which the storage is connected or local distribution companies.

MR. PARKER: I think that in the NPC detailed writeup, there is consensus that market-based rates are appropriate for storage where you have competitive markets. That's something you'll find in there, and I know the Commission reviews that, and that's something you see on a daily basis. So, from an industry standpoint, we did get some consensus there at the NPC level.

CHAIRMAN WOOD: How do you define competitive market?

(Laughter.)

MR. PARKER: That's a good question. I don't think we had consensus on how you define competitive market, other than, you know, it requires a level of competition in order to be justified.

CHAIRMAN WOOD: Competition between storage facilities?

(Laughter.)

MR. PARKER: I certainly believe that different entities at the table might answer that question differently, but I don't think we looked at it as storage-on-storage. We looked at it more from a market perspective, whether it be pipelines or storage, but competition.

(Slide.)

MR. DANIEL: Just in summary, then, a few conclusions from the Storage Task Force are that the demand profiles are changing, requiring greater flexibility from the storage system and greater flexibility, not only physically, but in the commercial services they provide.

The demand for seasonal storage capacity will continue to grow by about 700 Bcf over the period. The greatest risk to the adequacy of the system, we believe, if you get that degree, still remains the potential for extreme winter and the conclusion that FERC should allow operators to adapt to these changes in the market as much as possible by configuring transportation and storage infrastructure and related services in the most flexible possible light. Thank you.

MR. PARKER: That concludes the T&D portion, Mr. Chairman. If there are any questions --

(No response.)

MR. PARKER: I will have the last piece, and the conclusion, I think, will be by Jerry.

MR. LANGDON: As I said at the outset, my job is to tell you what we told you. We believe there has been a fundamental shift in the way natural gas supply and demand balance is going to formulate itself going forward.

Higher prices and volatility are probably here to stay. We expect those issues to continue, but we think there are tools out there to moderate them on a going-forward basis.

On the demand side, in terms of finding greater efficiency in conservation, clearly, is alternate sources of energy. While we think gas consumption will grow, price-sensitive industries become less competitive.

From the supply side, traditional North American producing areas will provide 75 percent of the going-forward long-term supply for this country, but we're going to have to bring in some other sources: Increase the access to U.S. resources, not including, importantly, wilderness areas, National Parks, those kinds of things that we deem to be off limits.

We'll bring in an additional $300 billion of savings to natural gas consumers over the next 20 years. Without LNG and Arctic gas, which we think makes up as much as 20-25 percent of demand going forward, we're going to see much higher prices going forward.

Infrastructure: The average will be about $8 billion a year in costs, just to maintain what we've got out there, and to sustain the reliability of the infrastructure system.

Regulatory barriers to long-term contracts for transportation and storage will impair investment in those facilities. Again, price volatility is a fundamental aspect of free markets. Those of us who considered some of these things 12 years ago, I think, thought about that and considered that price volatility was going to be a part of the competitive market.

I think it took ten or 12 years to fully develop. There are risk management tools available and we think the parties are getting better at using those risk management tools going forward. I should have done this 30 minutes ago, shouldn't I?

(Slide.)

MR. LANGDON: Finally, on the demand side, for the recommendations: A balanced future that includes increased energy efficiency, immediate development of new resources, and flexibility in fuel choice, will save gas consumers a trillion dollars over the next 20 years, but we believe public policy has to support all of these objectives.

On the demand side, that we improve flexibility and efficiency; on the supply side, at the top of the list, that we increase supply diversity, infrastructure that we sustain and enhance the infrastructure, and the last one, markets, that we would promote efficient markets.

With that, Mr. Chairman, Commissioners, Staff, we can't tell you how much we appreciate having the opportunity to be here for this forum. This is kind of hard to believe, but this represents really sort of the tip of the iceberg. There's a whole lot more underneath that's pretty good data that should be out there.

We don't suggest that what we're saying is going be right, long term. It's just kind of our best guess as a starting point. We offer it to the community, the industry, and government to use as they please.

We think it's good work, and I've got to really tell you that the folks in this room and a lot more who are not here today, contributed just hundreds and hundreds and thousands of man-hours against this project. They are people like Rich Kinder and Lee Demen, and Bob Cottel and others. They have contributed a lot of pretty talented people to be here to contribute significantly to this.

But underlying this, 180 members of the Council have put a lot of money into this process or this work. It's been an interesting opportunity.

You really need to think about shifting the agenda from electric back to gas a little bit, if Ellen and Bob don't ask any questions during the day.

(Laughter.)

CHAIRMAN WOOD: They're not rusty, I promise. I can't thank you all enough for the collaborative effort you all did as members of the industry that care a lot about this great fuel, this very important resource for our continent, and the thoughtful way you laid it out. This was our day to be students in your classroom, and if the student gets to grade the teacher, you all get an A.

I have to say that the message is not good; it's not bad; I think it's pretty honest. To spend the time we did today and multiply that times a thousand, to spend the time y'all spent on it, there's a lot here that's credible.

Actually, with a few of your caveats, it's not least common denominator. I can see why it took you a while to get to some of these conclusions, because they are not just kind of a motherhood-and-apple pie conclusion. They are based on data, and I think that makes them both practical -- some of these are going to be hard to achieve.

I see one here, for example, the joint agency permitting process, and I wonder if, with the energy legislation here right now, if this is an idea. I'm not aware that that concept is very strongly in the legislation, although there are some attempts to try to get common record post-FERC Certificate approvals.

But I wonder if there is some way of sending a recommendation to Secretary Abraham, and that maybe if everything goes right, this is about the last week to get the suggestions into the Conference Committee. But I look at that one particular one right there at the bottom of your infrastructure, and this is the one time in every ten years we get the energy bills opened up to clean up the statute, and I wonder if there is some ability -- I'm certain that you would support that -- but some ability that the group can put that in to maybe Chairman Tauzin's ear. At least that's an area we have something to do with. The state issues are going to be hard.

Certainly, I think the state commissioners at NERUC will be back in town in February, but I'm not sure, Jerry. What's the outlook for that?

MR. LANGDON: As you know, Bob Keating has been integral through this process all the way through. He still chairs the Gas Committee at NERUC. We have participated in each of the NERUC conferences, the quarterly conferences. This has been going on, giving them updates.

We're going to have an opportunity to dump the whole load on him pretty quickly. We intend to do that.

In addition to that, we intend to do kind of an outreach program to walk around to specific PUCs, Governors, interested constituencies, to walk around, if you will, around the country to deliver as much of this message as is useful to those commissions.

CHAIRMAN WOOD: Great. I actually saw through the California issues when everybody woke up to the fact that you can't live on the spot market, I did see a number of the more practiced state commissions kind of make pretty dramatic changes in a pretty short amount of time, to make sure that hedging and long-term contracting and that type of thing that you all point out here, is available, certainly on the gas side and electric, depending on the state regulatory structure. But you're right. I wish we could fix that piece, but we certainly want to help send that message, because I have to send it just in a short amount of time to get absorbed by the listener.

Pretty well over the past, you did kind of gloss over the improved transparency of price reporting. As you know, we're kind of intrigued by that here at this Commission, and I guess I just want to offer that as to those two issues, I know that EIA had an issue there with the quality of the data that we use in this industry.

But please note that our Commission is very committed to that effort. We've made some initial approaches to that through the leadership of these guys, primarily. But we're not through there.

That's a subject of interest by Congress, both in the electricity and gas, and we might get a mandate there, so we'll kind of keep up with you all on that.

I know that was a little bit more, a quicker part of the presentation than some of the others, but it's one.

MR. LANGDON: We clearly support that. We clearly support the timeliness and accuracy of the data coming out of the EIA, for example. Those are becoming really important tools for the marketplace.

CHAIRMAN WOOD: Seven minutes after 10:30 every Thursday to get that little data. I know those traders are sitting there ready to punch a button. I have always worried that we have relied so much on one piece of data and that drives so much of the investment. I hope we can do more to broaden and deepen that transparency, because it's just too important. Brother Massey?

COMMISSIONER MASSEY: It's been a very educational day. I want to personally thank all of you for giving us a day of your time. I know a lot of work went into this report.

This Commission has been the beneficiary of all your good work and good ideas. With all the controversy and turmoil surrounding electric policy, it's really nice to have a conference where there's a general agreement on FERC's policy direction with respect to natural gas issues.

I don't hear a lot of objection to what we've been doing over the past few years. The message to me seems to be, steady as you go. Do your job quicker, if you can, give us as much regulatory certainty and stability as you can, but continue with the basic 636-based policies that the Commission has been implementing for years.

That's a nice message, I think, for this Agency, to feel like -- in general, I know there is some disagreement about right of first refusal policy and some other issues. Everything is not -- you wouldn't all agree on every issue to come before the Commission, but, generally speaking, it sounds to me like you believe the Commission is headed in the right direction, and I'm pleased to hear that.

Thank you for coming in.

CHAIRMAN WOOD: All right. Questions from the audience on Panel 3?

Last call for anybody who wants to visit about the NPC report with the folks on the report. Yes, sir?

MR. GREENE: My name is Joel Greene, with the law firm, Energy Advocates, in Washington, D.C. and Portland, Oregon. I'm here on behalf of the Northwest Industrial Gas Users.

With your permission, they have asked me to put a statement into the record. I have a copy for the Reporter.

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The Northwest Industrial Gas Users, NWIGA, is a nonprofit organization comprised of 33 industrial end users of natural gas, with major facilities in the states of Oregon, Washington, and Idaho. Members include diverse industrial interests, including food processing, pulp and paper, wood products, electric generation, aluminum, steel, specialty metals, chemicals, electronics, and aerospace and many of those key categories that Dena identified earlier today.

The Pacific Northwest, as many of you know, is still in the aftermath of the economic downturn that started for many of our members with skyrocketing electric and gas prices in 2000 and 2001.

Since then, many of our manufacturers in the Pacific Northwest have been forced to reduce production. Washington and Oregon have lost tens of thousands of jobs since 2000 and have the highest unemployment in the Lower 48.

Without reasonably priced energy supplies for their manufacturing processes, our members will struggle to compete in national and international markets and the citizens of our region will struggle to find family wages.

NWIGA endorses the NPC's recommendations and hard work in encouraging development of new natural gas production in Wyoming and Alaska. New sources of supply will be vital in meeting future demand for gas nationwide.

NWIGA's concern goes beyond the report, however, and is specific to our region. As new gas fields are developed, pipeline interconnections and increased infrastructure are needed to link the new fields with the Pacific Northwest.

Connections to the Canadian and U.S. interstate gas pipeline networks will be needed to connect Alaskan gas fields with our markets. The NPC report notes the growing demand for gas as a fuel of choice for electric generation and the many residential and commercial and industrial applications.

Our members are very concerned that gas and electricity pricing are increasingly linked, as was so evident during 2000 and 2001. The Pacific Northwest is increasing relying on natural gas-fired combustion turbines as the fuel for new electric generation, as is true for our nation.

NWIGA endorses the NPC's view that a balanced energy future should encourage alternative fuel choice. We would oppose limitations requiring specific fuel use for specific industries or electric generation applications, but wholly agree that alternative fuel choices should be promoted to reduce pressure on natural gas prices.

Without access to new supply sources, Pacific Northwest consumers will face higher prices than the Midwest, the South, and East, over the long term. An energy price disadvantage would further damage the Pacific Northwest's economy, crippling the region's ability to retain and attract manufacturers.

NWIGA strongly supports efforts to build the necessary pipeline infrastructure to connect our delivery network to new producing areas, whether in Wyoming or Alaska or both.

Infrastructure investment to connect our region to new fields is a critical element of energy policy for the Northwest.

Finally, an immediate concern of NWIGA is FERC's credit policy for interstate pipelines. NWIGA joins others who are calling on FERC to develop credit provisions for all interstate pipelines that are fair to both pipelines and shippers. The credit evaluation process should be transparent -- our favorite word today -- and based on actual risk.

NWIGA understands the purpose of this conference today to be general and not focused upon specific issues pending before the Commission. We will address our specific concerns in appropriate dockets, but would appreciate the opportunity to respond with further written comments in this proceeding, if the Commission determines to take specific actions as a response to the NPC report or other commenters today.

Thank you for this opportunity.

CHAIRMAN WOOD: Thank you, sir.

MR. GREGG: I'm John Gregg. I actually have a question. I also had a speech, but I promised Mr. Flanders I'd do it after 4:00. It's a question, albeit it's one that was asked and answered but I'm not certain I appreciated the answer this afternoon.

The centerpiece maybe of this afternoon's presentation were the two bar graphs about the need for capital investment, both in the interstate pipeline industry as well as the LDC community. The staff did ask why it was there was such a sharp decrease in the next five years and then an increase in expenditure thereafter. And that bounces around a bit. I just wanted to get clear whether this in fact is just a judgment of the NPC that overrode the model that made that happen. If so, what it was about the model that suggested a different result. And then, just intuitively or perhaps counter intuitively, how these changes in capital expenditure gibe with the rather steady and low growth and demand of 1% that's also presented in the report.

MR. PARKER: I can try to tackle that, Mr. Chairman.

There's a couple of things happening with capital charges, again, we colored in blue the MacKenzie and Alaskan pipelines so you see a big jump simply because those are significant investments and we decided to color them separately so you could kind of follow along with the chart and see those significant projects.

The reason you see a rise is because there's major investments. And you see a fall-off later in the chart simply because, as the model looks at this, LNG is added, remember, and comes on, we have capital investments to connect that LNG to existing infrastructure, but late in the model there's not a lot of new supply being connected. Early in the model we have the Rockies, we have Deep Water, and we have Arctic. Late in the model, it's simply LNG coming on. And we added that infrastructure on. So you see a bump up because of MacKenzie, you see it downward toward the end because there isn't a lot of major infrastructure in the model.

The other thing you see on the chart -- and we pointed this out -- is an increase in the capital costs to maintain the existing infrastructure, because we already went over that: the age, the utilization of the existing infrastructure when we connect the LNG and other supplies to it.

So I think that covered the questions.

MR. MAASSEL: Could I take my NPC hat off for one second and make a comment as part of the public, if you will? I just wanted to throw in the mix on this gas interchangeability issue the LDC perspective. It is a very important issue.

I cannot tell you that for our company to go back and try to work with 2.8 million residential customers to do something with their equipment because the quality of gas has changed somewhat -- I can't characterize that as a small task. Again, I just wanted to throw my hat in. This is a significant issue; it's not something you just tweak a couple of standards. I think there's real serious issues here.

CHAIRMAN WOOD: As I said before, that's life.

Anything else for the NPC folks before we let them go?

(No response.)

CHAIRMAN WOOD: Gentlemen and ladies, thank you very much. It was a very enjoyable day.

We'll break for about 10 minutes, then we'll do the final session of the program, which are non-NPC related issues from anyone in the audience.

(Recess.)

CHAIRMAN WOOD: I will just go in the following order. I'll read off the list of people we have: Chuck Linderman, EEI, John Gregg, APGA, Paul Cicio, Industrial Energy Consumers of America, Geoff Hurwitz, American Chemistry Council, and Joel Greene again from the Northwest Industrial Gas Users.

Joel, maybe we've heard from you, but you're welcome back.

Chuck.

MR. LINDERMAN: Good afternoon, Mr. Chairman, Commissioner Massey, I'm Chuck Linderman, Director of Energy

Supply Policy at the Edison Electric Institute. We represent the people that are the growth market here.

I want to talk a little bit about -- I'll take you back to that slide Keith Barnett showed earlier today where we are at the beginning of the uptick in new gas demand for power generation. There are three things I need to talk about with you: one is the interchangeability issue, gas and storage, and, finally, fuel switching and alternative fuels.

We are prepared to work with AGA, the Commission, anybody who wants to help to define the issues associated with fuel interchangeability and gas BTU standards, because that's crucial to our ability to effectively stay inside the warranty limits of the new gas turbines and combined cycles that we're putting in place throughout the industry. This has been a festering issue for some time and we hope to find ways to further its resolution as well.

We believe fundamentally, and as Chairman Kinder started out the morning, that there is a need for more flexibility and new services in this industry. We are intent, as we did two years ago with the non-uniform rate of flow services, to seek out those options and opportunities for both power generators and others so the industry maintains itself in a cost effective market based structure that avoids as much regulatory fiat as possible.

On dual fuel capability, Mr. Chairman -- and I could sense your unease earlier today. The numbers that we provided to the House of Representatives and the Senate in earlier testimony this year were that since 1993 through the year 2010, the power generation sector will put in place 355 gigawatts of new gas-fired combined cycle and combustion turbine capacity. Of that, only 14.5% is dual fuel.

That creates a number of challenges. It creates harder and higher gas pricing peaks because some of that capacity is in winter-peaking NERC regions such as New England, where it won't do any good to provide the gas into the residentials if the power generators don't have electricity to run to distribute that warm heat manufactured through your furnace.

We also know that in New England in particular, as again the demand slides showed this morning, about half the capacity is gas and oil up there. We can't ignore that in that particular part of the country as we think about electric reliability.

In terms of the other areas, many of the gas units that have gone in are in course in summer peaking regions where it's not quite as important to have dual fuel capability. But I would emphasize to you in your discussions with your colleagues at the state level, ask them the question about how they intend to hedge or arbitrage their gas expenses for power generation when they don't have the opportunity to even use oil 10 or 20 days a year as a minimal level of fuel use and fuel choice. Because we found historically that even an ability to switch a little bit creates a great price break and we need to have that as a price break on the market at the present time.

CHAIRMAN WOOD: Are you find the reluctance to do that is just the economic or does it have more to do with these environmental restrictions that are part of the permitting process for these new plants?

MR. LINDERMAN: It is both, Chairman Wood, I would say. In New England, in particular, it is local opposition to oil tanks, potentially oil trucks refilling that tankage, as well as environmental concerns, in addition to concerns by project developers of bad economics. There's no exclusivity to any one of those particular points. That is something that as a nation we need to think about in terms of critical infrastructure and electric reliability.

The other area that fits in some ways with that is our need for market area storage. Certainly as we develop and put in place more combustion turbines and more combined cycles in a hot summer we're going to need market area storage to support the hourly and daily swings that take place with those. And we encourage you to continue with the development of as much storage as is presented to you by the market.

Thank you.

CHAIRMAN WOOD: Thank you, Chuck.

Mr. Gregg.

MR. GREGG: Mr. Chairman, Commissioner Massey, staff, thank you for the opportunity. My name is John Gregg of the law firm of Miller, Balis and O'Neil. I'm here representing the American Public Gas Association and its 590 municipalities throughout the country; generally the voice for captive pipeline shippers. It's been rewarding in a number of ways to be here today and learn about the NPC report, but in two particular areas it's been rewarding to see that the consistency and persistency of some of our advocacy has paid off and that the important conclusions of the report are ones that APGA has had for a long time.

I'd like to talk about the need for alternative fuel for electric generation, as we just were, as well as market transparency and integrity. APGA's concerns about using natural gas to generate electricity dates back a number of years to when the Commission a few years back was considering a lot of applications for expansion specifically to serve electric generation customers. The twin concerns of the captive shippers on pipeline systems were the impact of such shippers on the operations of the pipeline and the potential that service to generators would degrade service to traditional shippers as opposed to the impact we've now seen of the impact of natural gas cogeneration on supply. We wanted to see dual fuel generators, but the Commission declined to impose any such certificate application on the pipelines.

The NPC report is perhaps most strong on the topic of alternative fuel capability and its disappearance. We learned today that industrial users have next to no dual fuel use any more and we just heard the statistic about electric generator dual fuel use. Maybe overall I would interpret the report as the proverbial Houston we have a problem. We've become so dependent on natural gas that the recommendation of the NPC is to increase energy efficiency and conservation. That is also the position of the administration. Ironically, just a couple of years after the infamous statement of the Vice-President that conservation was a virtue but not the basis of a sound energy policy. And the second problem beyond conservation is to do something about alternative fuel use.

So what can be done? What's striking to me about the report is that it seeks few non-market responses save changes to some environmental rules. The NPC wants a market-based competition to determine whether there is alternative fuel use, but to-date gas wins. And it seems in the foreseeable future gas is going to win. We heard today that price is not determinative; even in the wake of the dramatic rise in price there's been very little conversion. So it seems that reliance on gas is here to stay.

It begs the question what this Commission can do. I would just raise for discussion what that might be, whether it would be appropriate for this Commission to look at some advantages to give to dual fuel users, if in fact that is the appropriate policy alternative which people have. Certainly APGA would support efforts that would make the reliance solely on natural gas by these electric generators less dramatic.

Second, on the topic of market transparency, I think the Commission recognizes that APGA has been in the forefront of that discussion. Certainly we approve of the July Policy Statement and we feel it's a very good first step. Chairman Wood, you've said that that remains a front-burner issue for the Commission. APGA would like to see further steps taken. Voluntary compliance that the Policy Statement introduced probably isn't enough and we'd like to see a mandatory system with verification by counter-parties.

Lastly, a comment about rate of return and Section 5 of the Natural Gas Act. APGA should be well known in these quarters as one that keeps track of the length of time it's been since interstate pipelines have had general rate cases and had this Commission review their cost of service and returns. The absence of any Section 5 kind of enforcement on that does beg the question I think whether recourse rates remain just and reasonable.

When I came in this morning, I wanted also to talk a bit about rate of return and to point out a couple of things that have changed in the market. The ownership of natural gas pipelines really has changed dramatically. We now see that natural gas pipelines are viewed by a lot of investors, like Warren Buffett, as cash cows, as a great investment. Now they're part of large holding companies for good financial reasons. A 10-, 11-, 12% rate of return is deemed to be a good return. The rate of interest rates haven't been low in so long, so the cost of operating an interstate pipeline really should not be as high perhaps as historical rates of return suggest.

Although I did ask the question about capital investment earlier because I expected to hear a bit more, that there would be a need for the Commission to promote capital investment by enhancing rates of return, I don't think I really heard that and I don't think that that argument is really sustainable.

Thank you for the opportunity to make a few comments.

CHAIRMAN WOOD: Thank you, Mr. Gregg.

Mr. Cicio.

(No response.)

CHAIRMAN WOOD: Mr. Hurwitz.

MR. HURWITZ: I think I stand between the Commission and adjournment.

Chairman Wood, Commissioner Massey, thank you very much for this opportunity. My name is Geoff Hurwitz, Director of Government Relations for Roehm and Haas Company, a major global chemical manufacturer. But I'm here today on behalf of the American Chemistry Council, the principal voice of the U.S. chemical industry. And I'd like to state at the outset that we, the chemical industry, applaud the findings and recommendations contained in the NPCs report. In my view, the report is the most important wake-up call ever issued on the subject of natural gas.

The chemical industry is the nation's largest industrial consumer of natural gas. Last year, we consumed more than 2.5 TCF to fuel our operations and to use as a raw material or feedstock to make thousands of products that contribute to our standard of living. Accordingly, natural gas is a major cost of doing business in our industry. Three years of extreme price volatility is taking a terrible toll on the U.S. chemical industry. Affordable natural gas helped to make the chemical industry in the U.S. the largest exporter and the world's low cost producer of chemicals today. Largely due to the run-up in prices of natural gas, we are a net importer of chemicals and the world's high cost producer. Natural gas prices are as much an economic and jobs issue in our view as is the old energy versus the environment issue. Listen to what the NPC report says, and chemical companies are experiencing this daily:

The report projects that natural gas consumption by the chemical industry will decline by 25% in the next five years. Some of that will result from efficiencies, some of that will result from fuel switching. But most of that decline will come basically as a result of demand destruction: natural gas consuming factories shutting their doors and moving away. For far too long, in our view, our policy towards natural gas has been schizophrenic, encouraging its use while restricting its supply.

The NPC report does not shy away from exposing what this business-as-usual policy has wrought: high prices, reduced supply, shuttered factories. Yes, we must get serious about conservation and using gas efficiently, and the U.S. chemical industry will take a back seat to no one on both of those counts. Yes, we must maintain a diverse fuel base and create opportunities for consumers to fuel switch when market conditions warrant. Yes, we must invest in infrastructure. But most of all, we must increase gas supplies. More LNG and the Alaska pipeline are important mid- and long-term solutions. But for my industry, that may be too little, too late.

The key recommendation in the NPC report is that the time has come to lift moratoria on gas basins in the OCS and elsewhere and open those areas to environmentally responsible production. To those who say it can't be done, I say visit environmentally conscious nations. In Scandinavia and other parts of Europe. In Canada, where they do it. It can be done and it is being done.

The bottom line is the NPC report is right. OCS gas is the only source of new supply that can be brought to market in time to ease existing price pressures and restore our competitiveness. The choice is easy: to not do it or at least inventory it, as some in Congress would now restrict, defies reason in our view. I'd like to conclude by saying that we can no longer have it both ways with respect to natural gas. The NPC has created the definitive study of how we can right what's wrong. Its recommendations should become the law of the land.

Thanks. I'll be happy to take any questions.

CHAIRMAN WOOD: Thank you, Mr. Hurwitz.

MR. HEDERMAN: I have a question. Oftentimes when we hear about the cost of a price volatility, it's because it's an unsophisticated small consumer. The group you represent is a very sophisticated group. I was wondering how is it that they got caught without a hedge?

MR. HURWITZ: I would challenge the premise. We do, as most of the companies in this industry, do hedge. But hedging only goes so far when two years ago we were paying approximately $2.30, $2.50 an MCF and your price doubles and it chews up margins. The hedging that you have in place cannot account for that. Plus, you run out of the hedge over time.

When you look what's happened in the U.S. relative to the people that we compete against globally -- and the important point is that we compete in a global market where the U.S., in the space of two to three years, has gone from $2.5 an MCF to, at its peak, well over $7 and $10; it's stabilized a bit now below $5 -- but when you compare those numbers to what the Europeans are paying, to what the Asians are paying, we are paying the highest prices in the world versus regions of the world against whom we compete. So when you take that cost, coupled with the other costs that are part of doing business, margins get destroyed.

And the U.S. chemical industry is largely a global industry when we are not tied to our manufacturing plants in the United States. We'd like to be in the United States, that's our preference. That's where our infrastructure is, our economies of scale, but we can move and you're starting to see that happen. And it's very unfortunate.

MR. FLANDERS: What can you tell us about the feedstock evolution over time? Can the chemical industry design its way out of this by switching to coal or some other mechanism?

MR. HURWITZ: Bob, I think the short answer is yes, but I think you said the critical variable: it's time, and it's money. And when you have a chemical process that has been designed to run based on the current feedstock mix that we have, to make the shift that you're talking about is enormously capital-intensive. The fact of the matter is that this industry for the foreseeable future is a hydrocarbon-based industry. You can get the gas from Germany for $2 an MCF. You can see basic petrochemical markets in the Middle East and the Persian Gulf where natural gas virtually has no value and you're starting to see slowly the shift in basic petrochemicals to those regions where gas is not cheap.

We have a lot of advantages in the U.S. in terms of technology and know-how and economies of scale, but eventually those price disparities are going to catch up long-term. Yes, I think your point is well taken. But not in the immediate short-term.

MR. FLANDERS: What would you say to the argument that that's just the natural evolution of the world economy, that production gravitates toward the lowest cost?

MR. HURWITZ: This could be construed by some as controversial. I would agree with that point if the United States wasn't awash in natural gas. It's not -- I mean, it's basically an artificial situation that's causing this shortage. You're driving demand, as I said in my statement, for environmental reasons -- all legitimate good reasons -- to use this wonderful resource but then restrict its ability to be found and produced when no Western democracy, in my knowledge, does that. I think you've got a policy that, as I said, is a bit schizophrenic.

MR. MURRELL: Mr. Hurwitz, would you care to give us your reaction to the NPCs recommendation that there should be some kind of nationwide interoperability standard for the quality of natural gas?

By that, I think what they were talking about is expanding to a higher level of BTU quality and perhaps the introduction of nitrogen or other inert substances to create a uniform burning characteristic.

MR. HURWITZ: What I prefer to do than give the answer right now, because that's probably a little bit beyond my expertise, but if I can get an answer back to you from the ACC, I'd be happy to do that.

MR. MURRELL: That would be of interest to me. Thank you.

CHAIRMAN WOOD: You can just file that in the docket for today's publication, as can anybody that wishes to file additional comments.

Thank you.

MR. HURWITZ: Thank you.

CHAIRMAN WOOD: Mr. Greene, or anybody else we heard from earlier?

(No response.)

CHAIRMAN WOOD: Would anybody in the audience like to add anything?

Yes, sir, please come forward.

MR. WILSON: Jim Wilson again with LACG. I have a few comments about market area storage. Market area storage can really help a market work well, but it's risky to build mainly because its value is squashed every time you have ample or even excess pipeline capacity. Therefore, it's really not like a pipeline whose value has a much more stable foundation. Market based rates, market power, the question came up earlier. Are storage facilities a relevant market? I believe they're not. It's not a well-defined market. I won't elaborate on that because you have my views on that in the Red Lake gas storage proceeding, rest in peace.

You might want to consider California's very successful storage policies. They had a proposal for a merchant storage facility in the mid-Nineties. They got market shares, they got HHIs -- I'm interpreting here, of course, but they basically scratched their head and said I can't tell whether a storage facility has market power or not, so just go ahead with market-based rates. And if you misbehave, we'll get you.

It's worked fine. Northern California now has another merchant storage facility and the market there is very competitive. You have monitoring in place. And I think, should anything go wrong -- which I don't think is very likely in storage because it competes with pipelines and demand response, et cetera, but you'll be able to deal with it very effectively nowadays, I believe.

Negotiated rates for storage, a lot of market participants, potential market participants, potential sponsors are really wondering what that might mean for a market area storage facility. Anything you can do to clarify exactly what would or wouldn't be allowed, I think, would really help the market right now, as you know.

I can tell by your faces you're going to ask me exactly what the questions are. I don't have a good answer.

CHAIRMAN WOOD: Have you got a recourse rate? We've been pretty -- Bill and I agree about restricting it to basin differentials, which could be relevant for storage. But is there much of a restriction? I'm looking at the Staff guys here. You've got the recourse rate set. Is there much of a restriction on the gas generation in a market storage context?

MR. MURRELL: I think as a practical matter more often than not a FERC jurisdictional storage operator would have market-based rates. I'm not actually sure that any of the FERC jurisdictional storage companies have sought to use negotiated rates. I'm not sure I've ever seen a filing for negotiated rates under that program. It's mostly been market-based rates and at that point we don't have any more information.

CHAIRMAN WOOD: Tell them to come talk to us. The California analogy is actually pretty intriguing.

MR. WILSON: Thanks.

CHAIRMAN WOOD: Anybody else?

(No response.)

CHAIRMAN WOOD: Last call.

(No response.)

CHAIRMAN WOOD: Thank you all very much.

(Whereupon, at 4:35 p.m., the conference was adjourned.)