BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC :

CONSENT MARKETS, TARIFFS AND RATES - GAS :

CONSENT ENERGY PROJECTS - MISCELLANEOUS :

CONSENT ENERGY PROJECTS - CERTIFICATES :

DISCUSSION ITEMS :

STRUCK ITEMS :

- -x

946TH COMMISSION MEETING

OPEN SESSION

Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, N.E.

Washington, D.C.

Thursday, April 16, 2009

10:00 a.m.

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN JON WELLINGHOFF (Presiding)

COMMISSIONER SUEDEEN G. KELLY

COMMISSIONER MARC SPITZER

COMMISSIONER PHILIP MOELLER

P R O C E E D I N G S

(10:03 a.m.)

CHAIRMAN WELLINGHOFF: Good morning. This is the time and place noticed under the Sunshine Act for the April Open Meeting of the Federal Energy Regulatory Commission. I want to thank you all for being here. If you'll join us in the Pledge of Allegiance.

(Pledge of Allegiance recited.)

CHAIRMAN WELLINGHOFF: I want to recognize that we have with us here this morning a visitor from the Economic Regulatory Authority of Western Australia, Robert Pilule (phonetic). Robert.

(Applause.)

CHAIRMAN WELLINGHOFF: I want to indicate that today marks the first open meeting since President Obama designated me to serve as Chairman of the Federal Energy Regulatory Commission.

(Applause.)

CHAIRMAN WELLINGHOFF: I am deeply honored by the President's action and I want to thank the President for his confidence he has expressed in me to take this role.

I also would like to thank my colleagues who have been supportive and ever helpful during this transition.

And finally I would like to express my sincere appreciation to the highly professional staff of this

Agency. Without you, we could not carry out the Commission's important responsibilities. It is an honor to come to work every day with the best and brightest in the Federal Government.

Before continuing, I want to announce that Shelton Cannon has decided, after 29 years of service, that he is retiring from the Commission. I begged Shelton on one knee to not do that.

(Laughter.)

CHAIRMAN WELLINGHOFF: But I want to extend my gratitude and admiration for his work here.

Shelton has been called an economist, an engineer and an attorney. However, I think Shelton is best described as an exceptional public servant. Shelton's service at the Commission has been selfless, tireless, diligent, and focused.

On one level, Shelton has been involved with developing our major policy initiatives. His advice consistently reflects great expertise and judgment.

On another level, Shelton has excellent people skills. Within the Commission has is known for taking the time to teach our developing analysts and, just as importantly, giving them opportunities to succeed.

With state commissions, utilities, and many others, Shelton has built bridges and diplomatically

provided information and perspective on what are sometimes contentious policy debates.

The respect that Shelton has earned from all parties has enhanced the Commission's reputation as an agency that is recognized for leadership, respected for its expertise, and balanced in its decision-making.

Shelton, I want to thank you very much for your service, and I am pleased to recognize you with a Career Service Award.

(Applause.)

CHAIRMAN WELLINGHOFF: Colleagues, if you want to comment about Shelton? I'm sure you all want to say something about Shelton.

COMMISSIONER MOELLER: Mr. Chairman, I will be brief. He is a legend in a good way, and he will be missed.

COMMISSIONER KELLY: I know Shelton doesn't want any testimonials, so I would just like to add that I will miss you very much.

COMMISSIONER SPITZER: Mr. Chairman, fabulous job. Wonderful public servant. Great career. Thank you, very much.

MR. CANNON: Thank you all. And all I can say is thank you to everybody that has helped me over the years. I am really going to miss this place.

CHAIRMAN WELLINGHOFF: Thank you, Shelton.

MR. CANNON: But I am going to enjoy the gardening.

(Laughter.)

CHAIRMAN WELLINGHOFF: Couldn't get him away from the gardening.

I would also like to take this opportunity briefly discuss my priorities as Chairman. I intend to build upon the Commission's reputation as an agency that is efficient and timely in its decision-making, respected for its technical and legal expertise, and recognized for the leadership it brings to the energy issues confronting our Nation.

Toward that end, we will maintain our commitment to four fundamental Commission responsibilities:

Developing needed energy infrastructure;

Fostering competitive energy markets that produce just and reasonable rates;

Overseeing reliability standards; and

Effectively enforcing both market and reliability rules.

Since I joined the Commission in 2006 I have emphasized that fulfilling these responsibilities must involve action on issues the Commission has only recently begun to pursue aggressively. Those issues include:

Exploring how to best incorporate demand response

and other demand resources into wholesale electric markets;

Enhancing transmission planning and market rules and operations to allow reliable integration of renewable energy resources; and

Pursuing continual improvements in operational and technical efficiency across all aspects of the industries we regulate.

We have made considerable progress on these issues in the past two-and-a-half years. Those achievements owe a great deal to the efforts of former Chairman Kelliher, as well as to the leadership of and collaboration among my fellow Commissioners.

For example, Commissioner Kelly has played a significant role in the Commission's work on developing a Smart Grid. Thank you, very much.

Commissioner Moeller has been a leading voice on the need for investment in infrastructure, particularly electric transmission facilities.

And Commissioner Spitzer has played a key role in the Commission's work on competitive power procurement and in highlighting the potential benefits associated with the development of plug-in hybrid electric vehicles. Thank you.

However, there is more work to be done. We are at a critical juncture in the development of our Nation's energy policies. Our existing infrastructure is too often

inefficient and will not be capable of meeting our Nation's future energy needs and challenges. We must develop the technologically vibrant systems that our Nation's consumers deserve.

In addition, the intersection between environmental policy and energy policy is becoming increasingly important. Indeed, issues surrounding climate change, renewable resources, energy efficiency, and developing a smart grid are emerging as drivers for energy policy.

These same issues are front and center in the emerging energy policies of the new Administration, as well as the subject of a number of legislative initiatives currently being considered on Capitol Hill.

As we build on the Commission's experience and expertise to address these issues and challenges, I will be looking for ways to encourage and incorporate new ideas and fresh approaches into our decision-making process.

With that, I am pleased today to announce the creation of the Office of Energy Policy and Innovation, effective May 4th. I am also pleased to tell you all that Jamie Simler has agreed to serve as the Director of this new office. Jamie has 23 years of experience in the energy industry, both public and private sector. She has been the Deputy Director of the Office of Energy Market Regulation

since 2005. Prior to that role, she held several positions of increasing responsibility, and also was an advisor to one of the commissioners.

With Shelton's retirement, Mike McLaughlin will become the Director of OEMR. Mike is a veteran regulatory with 25 years of experience at the Commission. Mike began his career at the Commission as an advisor to a commissioner, and he has held a number of senior management positions within the Commission, including Division Director of OEMR for a number of years. Most recently he has been Deputy Director of the Office of Electric Reliability. Thus, Mike will bring a unique combination of knowledge about economic and reliability regulation to his new position.

Anna Cochrane will become Deputy Director of OEMR. She has 25 years of experience in the energy industry. She has worked both in the private sector and at the Commission. Since 2006, Anna has been Deputy Director of the Office of Enforcement.

These new office leaders are characterized by broad experience and outstanding achievement. They will do a great job.

Lastly, I would like to acknowledge the hard work of my own personal staff during the past two-and-a-half years: Jim Pederson, David Morenoff, Mary Beth Tighe, and

Mae Travers.

As announced last week, Jim is taking on a new position as the Commission's Chief of Staff. David and Mary Beth will become, respectively, my senior legal policy advisory and my senior technical and policy advisory. As my confidential assistant, Mae plays a vital role in the efficient operation of my office. Christy Walsh has recently joined my staff as a legal and policy advisor. And finally, LaShonda Swann serves as my office visual information specialist.

I look forward to serving as Chairman of the Commission. I want to commit myself to working with my colleagues at this table, my friends, fellow regulators at the state level, other federal departments and agencies, the industries we regulate, and the many others who are interested in the Commission's proceedings, all in the interest of consumers.

With that, I think we can move ahead with Madam Secretary.

SECRETARY BOSE: Good morning, Mr. Chairman. Good morning, Commissioners.

Since the issuance of the Sunshine Act Notice on April 9th, 2009, Item E-1 has been struck from this morning's agenda.

Your Consent Agency for this morning is as

follows:

Electric Items: E-2, E-5, E-7, E-8, E-9, and E-10.

Gas Items: G-1 and G-2.

Certificate Items: C-2 and C-3.

As to E-8, Commissioner Kelly is concurring in part with a separate statement; and Commissioner Moeller is dissenting in part with a separate statement.

We are now ready to take a vote on this morning's Consent Agenda items beginning with Commissioner Moeller.

COMMISSIONER MOELLER: Vote aye, noting my partial dissent in E-8.

SECRETARY BOSE: Commissioner Spitzer.

COMMISSIONER SPITZER: Vote aye.

SECRETARY BOSE: Commissioner Kelly.

COMMISSIONER KELLY: Aye, noting my concurrence in E-8.

SECRETARY BOSE: And Chairman Wellinghoff.

CHAIRMAN WELLINGHOFF: I vote aye.

SECRETARY BOSE: The Office of Enforcement will be giving us a presentation this morning. Mr. Chairman, they will be giving a presentation on the state of the markets for 2008. There will be a presentation by Arnie Quinn. He is accompanied by Steven Reich, Christopher Peterson, and Keith Collins, all from the Office of

Enforcement.

(Slide.)

MR. QUINN: Good morning, Mr. Chairman and Commissioners.

CHAIRMAN WELLINGHOFF: Good morning.

MR. QUINN: Today I am pleased to present the Office of Enforcement's 2008 State of the Markets Report. This powerpoint presentation will be posted on the oversight section of the FERC website following this presentation. We will post the full report in the near future.

Today I am joined by Seven Reich, the Deputy Director of the Division of Energy Market Oversight; Christopher Peterson, who is the Chief of the Fuels Market Analysis Branch in the Division of Energy Market Oversight; and Keith Collins, who is the Chief of the Electric Market Analysis Branch in the Division of Energy Market Oversight.

The State of the Markets is staff's annual opportunity to share observations about natural gas and electric market performance during the previous year.

(Slide.)

(Slides.)

MR. QUINN: Today we will touch on a number of overarching themes. We will start by discussing the market forces that drove natural gas prices during 2008, a period of dramatic fluctuation and unprecedented summer prices.

We will first describe why we believe physical fundamentals, alone, cannot explain natural gas prices experienced during the first half of the year.

We will then discuss how trends in unconventional gas production and new infrastructure, which started several years ago, are fundamentally altering the nature of natural gas markets.

Second, we will describe how the financial crisis that hit the country during the second half of the year, altered the role of financial products and players in energy markets, and increased the cost of capital, while simultaneously reducing the access to capital.

We will then discuss the key drivers of electricity market outcomes. With the exception of the emergence of alternative energy sources, most electric market outcomes were driven by outside forces, specifically, fuel and commodity prices, and the financial crisis.

We will described how alternative energy options, including energy efficiency, demand response, and wind generation, have emerged as key components of

electricity markets.

We will then note several initiatives to broaden the scope of centrally-administered electric markets, including in regions that have depended solely on bilateral trading.

Finally, we will note early results from the Commission's efforts to enhance release of natural gas transportation service and reassignment of electric transmission service.

Before discussing these themes, I will provide a brief summary of natural gas and electricity price outcomes during 2008.

Average electricity and natural gas prices rose in 2008, and were substantially greater than prices in 2007, in virtually every region in the United States.

With a few exceptions, average natural gas prices were between 16 percent and 29 percent greater than during 2007. These exceptions were largely the result of infrastructure added during the course of the year.

For instance, average natural gas prices at Cheyenne, were 54 percent higher than 2007, due to increased pipeline infrastructure out of the Rockies, that allowed gas frequently bottled up in 2007, to flow to higher-priced markets.

This had a cascading effect on other regions.

Rockies gas that flowed to the Midwest, displays traditional mid-continent supplies that were able to flow to the southwest into Southern California.

This new flow pattern created a divide between Northern and Southern California prices, that Southern California began receiving mid-continent gas.

Rockies gas flows into the Midwest, also displaced higher-cost Canadian imports, which were down 12.5 percent in 2008, compared to 2007.

Driven by the increase in natural gas and coal prices, average electricity prices were between 12 percent and 21 percent greater than during 2007.

However, focusing on average prices, masks the incredible swings experienced during the course of the year. In fact, prices at the end of 2008, were lower than prices at the beginning of 2008.

This graph depicts average weekly spot prices at major electricity trading hubs, compared with fuel costs of a hypothetical 7,000 heat rate gas plant, based on the Henry Hub spot natural gas price.

The graph illustrates that the dramatic swing in electric prices, was driven by equally dramatic swings in fuel prices, principally natural gas, oil, and coal prices.

Although not displayed on this graph, I would note that Central Appalachian coal futures prices rose

dramatically from $55 a ton at the beginning of the year, to $117 a ton in mid-October, and then fell back to $62 by the end of the year. Other coal prices experienced similar fluctuations.

I will now discuss the physical and financial drivers of natural gas prices during 2008.

Natural gas prices increased during the summer of 2008, to levels never before experienced during any previous summer in the United States. Henry Hub prices peaked at $13.31 per MmBtu on July 3rd. By the end of the year, Henry Hub prices had fallen to $5.71.

Our review of physical fundamentals during the first half of 2008, suggests that supply and demand factors alone, cannot explain the dramatic swing in prices.

Nonetheless, there were a number of discrete issues that put upward pressure on prices. A cold January led to the highest gas demand in ten years and the largest withdrawal from storage in 11 years.

Net gas imports from Canada, were down 14 percent during the first half of 2008, while LNG imports were off 64 percent. The offshore Independence Hub, had to shut down repeatedly during April and May, losing up to 900 million cubic feet per day or about 46 Bcf for the entire period.

A hot June led to a surge in gas consumption from power generators, to meet air conditioning load.

Similarly, a number of discrete issues contributed to lower prices in the second half of 2008. A relatively cool July and August helped moderate demand from power generators, the financial crisis contributed to declining gas demand, particularly from the industrial sector in the final quarter of 2008, and gas storage recovered to levels above the five-year average.

All of these discrete issues ultimately have to have acted through the overall market balance, which we address more closely in the following slides.

Overall, the supply/demand balance in 2008, was unexceptional. We'll address supply-and-demand dynamics during the first half of 2008, separately, to start, before turning to the combined effect of these dynamics.

Notwithstanding the discrete issues identified, there were no major disruptions to supply during the first half of 2008, that would explain the increase in prices. Total gas supply, including domestic production, pipeline imports and LNG imports, was up three percent through June of 2008, relative to the same period in 2007.

In September, Hurricanes Gustav and Ike, did cause a considerable drop in supply availability, more than ten Bcf per day. This drop, however, occurred after gas prices began their precipitous late summer decline, briefly interrupting but not ending the price's downward

trajectory.

Gas use through June of 2008, increased 3.6 percent, relative to 2007, primarily because gas demand in January and March, was higher than in 2006 and 2007.

Supply and demand do not work in isolation, rather, the overall balance of supply and demand, dictates the relative tightness of the natural gas market. As this graph illustrates, the supply/demand balance through June 2008, was not significant more bullish than the five-year average balance, except in January.

Importantly, there was not an exceptional surplus of gas in July, when prices started to fall dramatically, though the August surplus was large.

Therefore, with the exception of January and August, the overall supply/demand balance, was unexceptional.

An alternative measure of natural gas market tightness, is the amount of gas in storage. To a large extent, this measure should track the supply/demand balance, as the supply imbalance is met by withdrawing gas from storage.

As the winter of 2008 progressed, storage levels fell steadily, relative to the five-year average, reaching the five-year average by the end of March.

The United States had not experienced storage

levels at or below the five-year average in the recent past, thus, it is possible that relatively low storage, affected market perceptions and thus explain some of the increase in prices during the first three months of 2008.

However, the level of price increase, was unprecedented, relative to recent experience, as illustrated by this graph. This graph is a scatter plot covering recent periods of storage at or below the five-year average.

The horizontal axis shows the storage surplus defined as the difference between EIA's weekly storage number and the five-year average. The Y-axis shows the average weekly spot price at the Henry Hub.

The points are color-coded to correspond to the year when they occurred, with a trend line for the year in question, showing the general relationship between prices and relative storage levels.

The general shape of the curve, shows that below-normal storage levels coincide with higher prices, and above-normal storage levels coincide with lower prices.

However, the shape of the curve for 2008, is much steeper than in prior periods; that is, in previous years, extremely high prices corresponded to periods of much larger storage deficits.

In addition, much of the period of relatively low gas storage, occurred in the spring and early summer, when

those injecting gas had the maximum flexibility in their storage choices.

As a result, the steep price increase likely caused the low inventories. In addition, storage levels remained at relatively low levels through July and mid-August, though the storage level was coming back to the five-year average, as natural gas prices fell dramatically, which suggests that in the adverse market perception, related to low storage levels, dissipated quickly.

In summary, while physical fundamentals, particularly storage levels, can explain why natural gas prices rose during the first six months of 2008, none of the market fundamentals were extreme enough to explain why spot Henry Hub prices reached $13.31 by July 3rd.

As we discussed at the winter assessment last Fall, the rise in natural gas prices coincided with a global increase in many commodity prices. This increase in commodity prices occurred as large pools of capital flowed into various financial instruments that essentially turned commodities like natural gas, into investment vehicles.

Ultimately, we believe that financial fundamentals, along with the modest tightening in supply-and-demand balance for gas during the first part of 2008, explains natural gas prices during the year.

Today, natural gas prices are below $4 an MmBtu.

The physical factors that drove prices in the fourth quarter of 2008 and the first quarter of 2009, have the potential to fundamentally change the natural gas markets over the next few years.

In short, natural gas is not scarce. Going forward, a key consideration is whether natural gas production will be able to get into balance with consumption in a manner that will not lead to an exaggerated boom/bust cycle.

Natural gas production growth has been concentrated in what has been traditionally referred to as unconventional gas fields. These fields include tight sands, coal-bed methane, and shale formations, some of which are located near traditional producing basins, while others are located in remote areas.

In 2008, unconventional gas production represented 51 percent of total natural gas production, and grew 14 percent in 2008, while conventional production declined by three percent in 2008.

These unconventional gas plays have become economic, due to innovations in horizontal drilling and fracturing technology.

Unfortunately, there is a limited amount of information available on prices needed to cover operating costs and capital costs, including a reasonable return on

investment, and the available estimates are disparate.

On the low end, break-even prices ranged from $3.31 per MmBtu, to $5, and, on the high end, break-even price estimates for most producing basins are in the range from $5 to $7 per MmBtu.

Given the plausible range of break-even prices, prices at the end of the first quarter of 2009, are somewhat below the prices needed to sustain drilling activity in most unconventional basins.

This is borne out by the dramatic plunge in the gas rig count during the fourth quarter of 2008, from a peak of over 1600 in early September, to less than 900 currently.

If sustained, the slowdown in drilling will likely lead to much lower production growth or to even production declines, which could lead to much higher prices when industrial gas demand rebounds.

A key issue is whether the natural gas market will be able to move available low-cost supply to consumption centers. By the end of 2009, new production and infrastructure is posed to transform the natural gas markets in major consuming regions.

Chief among these projects, is the Rockies Express Project. On January 9th, 2008, Kinder Morgan finished Phase II West of the Rockies Express Pipeline, which transports 1.5 Bcf per day of natural gas from major

production fields in Colorado and Wyoming, into central Missouri.

Rex II West interconnects with several major Midwest pipelines, allowing Midwest shippers, access to lower-priced Rockies gas. The first phase of Rex III, is scheduled to be in service by June 15th, with some interim service to central Indiana available by mid-May.

After the commencement of REX II West, transportation price differentials between the Rockies and the midcontinent declined, as the new pipeline linked the two regions and allowed the prices to track more closely.

As illustrated in this graph, in 2008 the average physical price differential between the mid-continent region and the Rockies declined by 68 percent, or $1.39 per MmBtu, from the previous year.

As REX II reached capacity during the summer of 2008, the chart notes the corresponding increasing in the price differential indicative of the constraint to transport cheaper Rockies gas further east.

Overall, pipeline capacity has been added to better integrate robust unconventional natural gas production into the national pipeline grid. EIA estimates that intrastate and interstate natural gas pipeline developments added an unprecedented 45 billion cubic feet per day of new capacity, three times more capacity than the previous year.

Also noteworthy is the magnitude of the pipeline projects, with many designed to transport over 500 million cubic feet per day.

Finally, potential liquefied natural gas imports are another potential short- and medium-term driver. During 2008, the United States received less than 1 Bcf per day of

LNG as prices in the rest of the LNG-importing world were higher than U.S. prices. Asian and European demand was high, and there were occasional supply shortfalls.

However, world LNG prices have fallen substantially since the end of 2008, to the point that northeast prices for natural gas were on par with the rest of the world by the end of March 2009.

In addition, additional LNG supplies are coming on line and Asian and European demand has fallen off. Some analysts foresee U.S. imports greater than 3 bcf per day by the third quarter of 2009. A large inflow of LNG could put substantial downward pressure on natural gas prices, especially if U.S. demand does not rebound or production growth does not slow.

(Slide.)

We will now describe how the financial crisis seems to have spilled over into energy markets. We will start by describing the evolving role of financial energy products over the last few years.

We will then describe how financial energy trading changed after the financial crisis started. Finally, we will discuss the long-term implications of the financial crisis on energy market participants.

During 2008, financial products continued to play a growing role in energy markets. As this graph depicts, in

the electricity markets financial contracts continued to play an increasingly prominent role.

Starting with the third quarter of 2006, financial trading on IntercontinentalExchange, or ICE, has increased relative to the previous year every quarter until the fourth quarter of 2008.

At the same time, physical sales of electricity, as we report in the electric Quarterly Report, have fallen every quarter relative to the previous year since the fourth quarter of 2004 with the exception of the first quarter of 2008.

We have categorized EQR sellers into three broad categories: utilities, independent power producers, and financial institutions and marketers, based on the company that files the EQR.

Based on this determination, we can see that much of the drop in physical market activity is the result of fewer sales by the financial institutions and marketers. This is particularly true in California, the Pacific Northwest, ISO-New England, and PJM.

Similarly, as we have documented previously the volume of financial natural gas trading dwarfs physical natural gas trading. NYMEX and ICE future trading, which is for a term of one month, is several orders of magnitude greater than monthly physical deals.

(Slide.)

As volatile as natural gas and electricity prices were during the first half of 2008, the capital markets were equally volatile during the second half of 2008. As financial institutions experienced growing distress, the energy markets were affected in two ways.

First, trading of financial energy products decreased, while financial institutions and energy marketers took a smaller role in energy markets.

Second, energy market participants experienced reduced access to and a higher cost of capital resulting in reductions in capital expenditure budgets.

As this graph illustrates, by August 2008 the volume of financial electricity product trading on ICE dropped relative to the previous year. This occurred after dramatic increases from January through July.

This pattern held in most of the largest volume trading hubs. For instance, in the largest ICE trading hub, PJM West, the fourth quarter 2008 trading wa down 39 percent relative to 2007.

Trading at both SP-15, the second largest hub, and NEPOOL, the fourth largest hub, was down just over 10 percent after earlier gains. The volume of fourth quarter 2008 trading at several other hubs, like Mid-Columbia, the third largest hub, and Cinergy, was flat relative to 2007

even though trading during the first part of 2008 was up substantially relative to 2007.

Despite the fact that the volume of financial trading has fallen, we note that additional financial electricity products continue to be developed. For instance, the Nodal Exchange, an electronic platform that facilitates trades of a number of financial electricity products, including something that is similar to financial transmission rights, began operation this month.

(Slide.)

Similarly, this graph depicts the fact that financial natural gas trading on ICE has declined in the last two months of 2008. It is important to note that the physical volumes are graphed on the right axis in order to illustrate this point.

The volume of financial trading continued to be an order of magnitude larger than physical trading. For the first 10 months, the volume of trading across all U.S. natural gas products traded on ICE was roughly 34 times larger than physical trading. By December, this ratio had fallen to 22.

(Slide.)

The financial crisis affected energy market participants in several ways.

First, the financial crisis limited the

availability of credit. During the Commission's January 2009 credit conference, a number of panelists noted that companies with lower credit ratings have not been able to access commercial paper or other short-term credit markets, with the availability and cost of credit from banks even more severely impacted due to their financial troubles.

As this graph of debt yields for electric and gas utilities depicts, for those utilities that have been able to access the credit markets the cost of credit has increased. The increase has been the most dramatic for noninvestment grade utilities.

As a predictable result of the reduced access to capital and increased cost of capital, a number of energy market participants have indicated the intent to reduce capital expenditures in 2009.

Oversight staff have been tracking announcements by natural gas producers of their intentions toi reduce capital expenditures in 2009 and beyond.

Based on a sample of the larger companies that have made such announcements, we have identified more than 20 producers who have announced during the latter part of 2008 the intention to reduce capital expenditures by more than $22 billion.

Some of the planned reductions are almost certainly related to the fall in natural gas prices and the

desire to rebalance supply and demand. Nonetheless, some of these announcements are also likely related to reduced access to capital and the increased cost of capital.

On the electric side, a recent report by the Edison Electric Institute indicates that capital expenditure budgets have been reduced by 10 percent for 2009 and 2010.

Oversight staff's survey of cancelled generation projects indicates that the capacity of canceled projects in the first quarter of 2009 is almost as large as the capacity of projects cancelled in all of 2008.

(Slide.)

Electricity market outcomes in 2008--including spot prices, fuel on the margin, and the construction of new electric generation--were driven largely by market forces outside the electricity market. With the exception of the maturation of alternative energy, the electricity market was like a boat on the ocean pushed up and down by external forces.

As I mentioned at the start of the presentation, electricity--spot electricity prices during 2008 were driven largely by the underlying fuel costs, with typical reactions to extreme weather events like the late spring run-off in the Pacific Northwest that drove down Mid-Columbia prices.

As fuel costs changed over the course of the year, the merit order of the electric supply stack changed

as well. This graph shows that during the first half of 2008 mildly efficient coal fired generating plants using coal from essentially any source enjoyed an operating cost advantage over natural gas fired generation.

(Slide.)

As this graphic illustrates, as natural gas prices started falling in July and coal prices stayed high, natural gas fired generation became competitive with plants that use eastern coal. In some regions, particularly the Southeast and the Mid-Atlantic, natural gas fired generation became competitive with any coal plan that did not use Powder River Basin coal.

This has the potential to effect operations as coal fired plants typically have a minimum operating level that is a small fraction of their maximum output, while combined cycle gas plants have a minimum operating level that is half their maximum output. To the extent that combined cycles become baseload plants, the availability of capability to ramp up in the morning and down in the evening may be reduced.

(Slide.)

Nationwide, during 2008 electric generating capacity was added at the rate experienced since 2005, which is substantially below the rate of additions from 2001 through 2003. The moderate additions in new capacity is

likely due in part to the fact that many regions of the country enjoy healthy reserve margins.

In addition, the moderate growth in new generation is also likely due to the fact that increases in construction costs and fuel prices led to increases in the cost of new generation during the year, as we discussed at our June 2008 presentation to the Commission on the Cost of New Generation.

The cost of constructing a new power plant increased almost 10 percent during the first three quarters of 2008, driven by increased costs for specialized labor as well as key inputs like steel and cement.

While underlying input costs dropped substantially in the fourth quarter, the measure of construction costs maintained by Cambridge Energy Research Associates, or CERA, held steady.

CERA attributes the absence of downward pressure on construction costs to the fact that equipment manufacturers and construction companies continued to have a backlog of orders. Our conversations with market participants validates CERA's conclusions.

In addition, during the last quarter of the year financing costs increased substantially and access to capital dried up, as discussed earlier.

Turning to the Northeast, while generation

additions were modest, at least relative to 2001 through 2003, energy efficiency and demand response programs emerged as a viable option for addressing future load growth.

As this graph depicts, ISO-New England cleared 838 megawatts of new demand response resources and 798 megawatts of new energy efficiency resources in its two forward 2008 capacity auctions.

Similarly, PJM cleared 29 megawatts of new demand response in its first forward auction in 2008, and 662 megawatts of new demand response in its second auction.

(Slide.)

The generation capacity that was added in 2008 was dominated by wind and gas-fired units. This is likely driven both by uncertainty related to carbon policy and regulatory policies, including state renewable portfolio standards and the Federal Production Tax Credit that facilitate the development of wind generation.

Overall, 8,376 megawatts of wind capacity was added in 2008, with over half of that total coming from Texas and Iowa, and more than 75 percent coming from just seven states. The top seven states have either high wind potential or a renewable portfolio standard, or both.

(Slide.)

This map depicts all states with either a renewable portfolio standard requirement or a voluntary

goal. During 2008, three states passed a new RPS, five jurisdictions amended or strengthened existing standards, four states with an existing goal strengthened them, and four states adopted a voluntary RPS or renewable goal.

Overall, 17 states include energy efficiency in their RPS or renewable goals, and at least three other states include energy efficiency in an integrated resource plan or other mandate.

Several states issued major energy plans or draft plans with goals encompassing renewable energy, energy efficiency, and greenhouse gas reductions, including California, Kentucky, Nebraska, New Jersey, New York, and Vermont.

Finally, we will note that the Commission took a number of actions to enhance the ability of demand response resources to provide ancillary services.

In its 2008 State of the Markets Report, PJM's market monitor, Monitoring Analytics, notes that "throughout 2008, the megawatt contribution of demand-side response resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices."

Monitoring Analytics went on to say that during 2008 demand side resources accounted for all cleared tier 2 synchronized reserves in 27 percent of hours when a

synchronized reserve market was cleared.

In the hours when all supply was from demand side resources, the unweighted average price was $2.58, while the unweighted average synchronized reserve price for all cleared hours was $8.49.

(Slide.)

A key development to monitor in the coming year is the expansion of centrally administered wholesale energy markets.

On January 6th, the Midwest ISO commenced its new Ancillary Services Market. The market optimizes the sale and purchase of regulation service--generation that responds to load changes every few seconds; spinning reserves and supplemental reserves simultaneously with MISO's energy market.

On April 1st, 2009, the California ISO commenced its new market referred to as the Market Redesign and Technology Upgrade Market System. Among other features, MRTU offers a day-ahead energy market, locational marginal pricing, a process to co-optimize energy and ancillary services, and a unit commitment process to maintain reliability.

Also on April 1st, Omaha Public Power District, Nebraska Public Power District, and Lincoln Electric System completed their transition to membership in the SPP regional

transmission organization. The three Nebraska public power entities are now active participants in SPP's energy imbalance service.

Finally, Southern Company developed a bid-based energy auction that will include both a day-ahead energy auction for firm-liquidated damages energy and recallable energy, and an hour-ahead energy auction for non-firm energy. Southern Company's energy auction is scheduled to begin next week on April 23rd.

We expect these developments to produce benefits with enhanced reliability and transparency, allowing buyers and sellers to transact with each other more efficiently and economically. Oversight staff will monitor these markets to determine whether they do so.

(Slide.)

Finally, I'll note that the Commission's capacity release reforms pursuant to Order No. 712 became effective in August 2008. Since that time, removal of the price cap for released pipeline capacity has not substantially altered pricing in the capacity release market. In the six months following the effective date of the final rule, releases above the cap comprised only 8 percent of all releases, and 7 percent of all capacity released.

Capacity releases above the tariff rate are limited to one year or shorter. In 2008 about 59 percent of

the premium-priced capacity released was for one year.

Nonetheless, there is still a market for long-term releases at the maximum tariff rate. In 2008, about 58 percent of the capacity released at the maximum tariff rate was for a period longer than one year.

If we consider the number of capacity release transactions, about two-thirds of the releases were monthly, regardless of the price of the released capacity.

Geographically, most of the capacity released occurred on pipelines serving the Northeast and Midwest. About half of the capacity released on the Northeast pipelines was at the tariff rate cap, and another 6 percent was above the cap. In contrast, about 77 percent of the capacity released on Midwest pipelines was discounted.

In Order 712, the Commission carved out exemptions to the capacity release rules to accommodate the development of asset management agreements.

In an attempt to capture AMA activity, we compared customer/agent information in the Index of Customers to release/bidder information in the capacity release database.

Instances where the bidder is identified as the pipeline's customer's agent constitute a small share of the capacity release market, but that share did increase during the six months after Order No. 712 from 3 percent in 2007-

2008 to 5 percent in 2008-2009.

The largest growth occurred in long-term released capacity which tripled between the two periods. Initial research from the Office of Enforcement's audit staff has indicated that AMAs tend to be executed near the beginning of the gas year on April 1st. This would mean that data still coming in will provide a more robust picture of Order No. 712's effect on the AMA market.

On the electric side, market participants that had reserved transmission service have been allowed to reassign that service above the tariff rate since Order No. 890 became effective during the second quarter of 2007.

There has historically been relatively little reassignment of electric transmission service. Since the second quarter of 2007, the quantity of transmission service that has been reassigned has steadily increased.

Capacity reassignments occurred throughout the non-RTO markets with no particular region standing out. The Mid-continent Area Power Pool has been the most consistently active region for reassignments, with Bonneville Power Authority System displaying a large increase in the fourth quarter of 2008.

The majority of completed transmission capacity transactions were for less than a day, though on a megawatt-hour basis yearly and monthly reassignments comprise the

vast majority of reassignments.

This concludes our presentation. We would be happy to take your questions.

CHAIRMAN WELLINGHOFF: Arnie, thank you very much. I want to thank Steve and Christopher and Keith, and the entire team for a very comprehensive presentation on the State of the Markets and the operation of them.

I really do appreciate the information especially about demand/response and how it is playing an essential role in keeping market prices down, PJM and New England. Also, your information on wind and renewable resources and how they are really adding to capacity in this country.

I also want to take this time to say a little bit about and recognize further, you mentioned how markets are also expanding, and services are being added to these markets. And one area in particular, which is the CALISO's market redesign and technology upgrade, the MRTU, I would like to thank the CALISO, California State agencies, and many other market participants who have been working hard for years to improve that MRTU process and to finally get it going and make it a reality.

I would also like to thank the Commission staff for their hard work in processing innumerable orders on the CALISO in the past several years. In fact, when I came to this Commission in August of 2006, I believe the September

agenda meeting was the first time we did vote on the initial MRTU Order.

I want to say, a fact I found out is since the middle of November there have been over 40 Commission Orders on MRTU, not counting numerous other ones, delegated orders have been issued. So the staff really we owe a debt of gratitude to for the hard work the staff did in processing these orders. They worked on many of these late into the evening, and again I want to thank you all.

Fellow Commissioners, any questions or comments for the panel?

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

CHAIRMAN WELLINGHOFF: Phil.

COMMISSIONER MOELLER: I guess this is directed to Arnie, but I welcome all four of you to opine on this. Which is, a lot of information, good information, as we're digesting it what's the big-picture-takeaway for both the electric industry and the gas industry?

What's going right? What do we need to work on? Is there anything that we need to immediately address in either category?

MR. QUINN: Well I would say right now we are experiencing some of the lowest natural gas and electricity prices that we have experienced in the recent past. Electricity prices in some regions are as low as they have

been since 2002. So as we sit here right now, price outcomes are very favorable.

What are the things from an oversight perspective that we worry about, or are monitoring? There are a couple of issues that are staying on our plate.

As we mentioned, the financial crisis does have the potential to have longer term effects. We are monitoring very closely the degree to which capacity generations are being cancelled and the degree to which drilling activity is going down.

Those have the potential that, while we have very low prices right now, to cause higher prices later on. So those are things that stay on our plate.

The other things that are, again, on our plate, and I don't know that we need to work on them, but that we're mindful of is that financial trading of energy products continues to be a big deal. And we don't, from an oversight perspective, have a great deal of information about what happens on the financial side. And that is something that we are staying diligent on and attempting to appreciate better the relationship between financial products and physical products for energy.

We noted the existence of Nodal Exchange. That is a new development, a new product, something that we are going to have to understand if we're going to understand

market outcomes in markets like PJM where they're offering those products.

COMMISSIONER MOELLER: Other thoughts? Chris?

MR. PETERSON: On the gas side, I think the big picture is the fact that gas really is no longer a scarce resource in the United States, and probably in North America.

This is a huge deal. If you go back about a decade, thoughtful people estimated that the potential resource base in the United States was around a thousand tcf. Current estimates now suggest that it's double that. So this has big ramifications for potential uses of natural gas going forward, and benefits to customers.

But that alone isn't what is important. What took place in 2008 I think was sort of a Manhattan-like project focus on bringing on line new pipelines, LNG terminals, storage facilities, and perfecting new techniques of manufacturing and getting as out of the ground.

That whole supply chain, working together, is what has created this environment where today we have gas prices that are currently about $3.60 per million Btu, as opposed to the $5 to $7 band we were in for over the last five years.

Commission efforts to certificate projects both here at FERC and through the significant component of the

new pipeline capacity that came on line that was also in intrastate pipelines, those policies clearly have helped get these new gas resources out of the ground and into markets.

One thing customers will likely see is, when they look at their PGAs for their winter gas bills next year, they may be about half what they were for the prior year.

COMMISSIONER MOELLER: My recollection is the EIA numbers said that domestic production rose about 7.2 percent last year, but domestic consumption only rose about .1 percent. That's mighty significant.

MR. PETERSON: Yes. An imbalance between the supply figures and the demand figures has formed, and that's why, as the winter played out currently I think we are at above the 5-year highs for gas storage inventories in the Western part of the country, and in the producing region. And part of that is, what you're getting at is we've had a large growth in supply relative to our gas that's been burned.

COMMISSIONER MOELLER: Thank you. Any other thoughts?

(No response.)

COMMISSIONER MOELLER: I particularly liked the last slide when you focused on Order 712 and kind of: Did what we did work? And I just want to also commend you for your ongoing look at that to make sure that how we did that

actually resulted in consumer benefits.

But maybe the most significant slide was your next-to-the-last slide pointing out that there have been big movements in wholesale markets just in the last couple of months with, as the Chairman noted, the successful rollout of MRTU, certainly from a reliability perspective, and the fact that we have the Southern Auction beginning next week. We have Nodal Exchange. And then we had three public power entities, essentially all of them Nebraska public power, electing to join an organized market. That is a very significant set of developments.

You mentioned that you will continue to monitor these markets. Can you elaborate on that just a bit?

MR. QUINN: I would be happy to. For California's MRTU, we had actually a very big part of the oversight function in the last month or so, or two months, as been preparing for that.

One of our staff analysts went to California to be with the ISO. We developed a number of kind of inhouse graphics to keep track of certain issues for us. A couple of issues have--the prices in general in California have been about what they were before, so the price outcomes all seem straightforward and consistent with what we had before MRTU.

But there are things that we watch. There has

been a lot of use of Exceptional Dispatch in California. I'm not sure if it's what the Commission expected when we passed those Orders. Those things are on our radar screen. So we have an ability to track those. We have good relations with the market monitor to appreciate what is driving those.

Real-time prices have been a little spikey in the ramping periods in California. That's true actually around the country. We have that as one of the things that is kind of on our plate to keep track of. Do they make sense? Is there something--for instance, SPP has a very similar issue and they have taken some actions lately to encourage market participants to offer more ramping capability.

So we have an ability to compare across markets and look at different tools different markets use to improve structural issues. So we will continue. We have a daily meeting. We have teams that are dedicated to specific regions. So we have an SPP team that has been on top of the Nebraska utilities integration for months.

We will in the future be looking for things like, did flow patterns between Nebraska and the rest of SPP increase after the Nebraska utilities were integrated? You know, where are the Nebraska utilities kind of showing up in terms of prices relative to the rest of SPP?

Very early indications are that the prices are

consistent with the rest of the region, but on the low end. So it kind of goes to our daily monitoring process.

And on the Southern Auction, we again have a Southeast team that focuses on market outcomes in the Southeast. Our staff analyst will go down to Southern to watch the auction start, and it will become part of our regular monitoring activities.

COMMISSIONER MOELLER: Well thank you for the presentation and the ongoing work.

Mr. Chairman.

CHAIRMAN WELLINGHOFF: Thank you, Phil. Suedeen?

COMMISSIONER KELLY: Thank you.

Arnie, I have two clarification questions and then I wanted to ask you some follow-on questions about three of your slides: 11, 10, and 7.

My clarification questions, the first one is: You gave us information on the transmission capacity release transactions that have occurred since we allowed reassignment of that service above the tariff rate. You didn't mention in the data here what prices they were selling at, whether they were at cap or above cap.

MR. QUINN: On the electricity side?

COMMISSIONER KELLY: On the electricity side. Do you have that data?

MR. QUINN: We do, and it's not particularly

good. The issue --

COMMISSIONER KELLY: Well, sorry. I probably should have vetted this question with you--

(Laughter.)

COMMISSIONER KELLY: --before I went onto national TV.

(Laughter.)

MR. QUINN: It's not our issue, I think; it's an issue of making sure that the folks who are posting on OASIS are posting something that's appropriate. We actually looked at this. We expected to do something.

It turns out the majority of people posting on OASIS post a price of zero. And we don't know how to interpret that.

COMMISSIONER KELLY: We suspect it's not zero.

MR. QUINN: It's potential that zero means at the tariff rate, and we haven't clearly communicated that we meant for the actual price. But that is something that we are going to continue to work on.

It is something we flagged during the State of the Market, and we have a game plan to kind address that in the future.

COMMISSIONER KELLY: Okay, thank you. Sorry about that.

Another clarification question was about the wind

capacity that was added in 2008. You mentioned that the seven states, the top performers in wind, had either high wind potential or an RPS, or both. Were they also in centrally administered wholesale markets?

We have learned--we have understood in the past that wind developers are particularly interested in locating in areas that have those markets because of the larger market area and the dispatch availability.

MR. QUINN: I would say, and I can tell you the list, to remove the mystery, it's Texas, Iowa, Kansas--which is not in an organized market but close to MISO, or SPP, I'm sorry--North Dakota--

COMMISSIONER KELLY: And Kansas can sell into SPP.

MR. QUINN: They can sell into SPP. North Dakota, which is in MIS, or abuts MISO; Wyoming; Minnesota; and Wisconsin. Minnesota and Wisconsin being in MISO.

COMMISSIONER KELLY: Okay, so, yes, they are, you would conclude? Keith?

MR. COLLINS: Yes. Most of them are in organized markets.

COMMISSIONER KELLY: Okay, thanks. Slide 11.

MR. QUINN: Yes.

COMMISSIONER KELLY: As you explained, we are seeing decreased liquidity in the financial markets in the

financial electric market. Can you postulate what this means for physical market prices in electricity?

MR. QUINN: I think in electricity we are more comfortable that physical prices are driven by generators and marginal costs in local areas, at least kind of in the very short term.

So we are comfortable, and we have a lot of experience seeing electricity traders talk about what prices they're willing to accept, and they're very much based on what the regionally marginal unit is. So they are more physically driven.

On a longer term basis, for say calendar year or monthly, or quarterly deals kind of going out in the future, I don't know that we have a view on whether this has affected those prices at this point.

COMMISSIONER KELLY: How about convergence in price, or price convergence across markets? Have you seen any decrease in convergence that might be related to this?

MR. QUINN: Convergence being the actual prices for energy relative to what the financial price would have been?

COMMISSIONER KELLY: Well, or the day ahead to the real time.

MR. QUINN: I don't know that--actually, I don't think the financial market activity that we're tracking on

ICE will affect the convergence of day-ahead and real-time prices. That is going to be something else. And our experience is that folks don't attempt to use, for instance, ICE day-ahead prices to try to duplicate real-time prices or day-ahead prices. That is more a function of behaviors within those markets--virtual bidding, for instance; or the things that they can do within the RTO markets.

COMMISSIONER KELLY: Okay. Thank you.

Slide 10. You explain that the drop in physical market activity is really coming out of the financial institutions markers category. What does that mean for the market? It's not being replaced obviously by an increase in sales by other sellers, so do we know who they sell to?

MR. QUINN: We do know--and I'll talk a little bit, but Steve did most of the work so I'll only say a little bit--Steve did some work on EQR data in the West specifically, and that work suggests that much of the drop in the financial institutions and marketers' activity in the West was they were trading less with each other, Not so much that they were trading less with an ultimate consumer of electricity.

MR. REICH: Eloquently put, Arnie. Exactly. In fact a lot of the drop that we see from the EQR data from quarter to quarter is certain participants who were very active in the market on quarter stopped being active in the

market, and so they've stopped being active both on the buyer's side and on the seller's side, and those tend to be financial players.

COMMISSIONER KELLY: Interesting. So do we anticipate that that is going to have an impact on the competitiveness of the physical markets? Probably not?

MR. QUINN: Yeah. The limited amount of information we've gotten from market participants in the West is that, especially as the financial crisis started in the fall, what they were seeing was a little bit more--a few more phone calls were needed to either sell or buy, but ultimately they were able to do it.

So, you know, the four or five marketers that they always could call on and rely on to have power, maybe a couple of them weren't there. So it took a few more phone calls, but ultimately they were able to still transact. And that is absolutely something that is at the top of our list of priorities to watch in the future.

COMMISSIONER KELLY: Thank you. And then finally, slide 7. That is an interesting graph, as you mention, an interesting curve. I know it was not your intent here to give us data on what the curves look like in surplus years. Did you happen to look at it? Is it similar to the steepness of the curve, at all similar to the steepness of curves in surplus years?

MR. QUINN: We have the surplus year curves. I'm trying to think off the top of my head. I think in general the surplus years, other than Hurricane Katrina, the prices just are in a much narrower band. I mean, they're between $6 and $8. And so it is necessarily flatter, just because there's less variation in the prices.

COMMISSIONER KELLY: As you mentioned, and as we discussed in the winter assessment last fall, the rise in natural gas prices coincided with the increase in many commodity prices, and then the increase in commodity prices occurred as large pools of capital flowed into the various financial instruments.

Obviously this hasn't happened since then. Do you anticipate that occurring again? Or do you think that that was an anomaly that was driven by something yet to be explained?

MR. QUINN: I think we have heard the very beginnings of the potential that commodities are again becoming an attractive investment vehicle. I certainly don't think we have seen the influx of capital yet, but when people call us up and talk to us we are hearing that the enthusiasm is growing a little bit more.

COMMISSIONER KELLY: What is the implication of that kind of activity for consumers in the gas industry, either local distribution companies or purchases of gas? Is

it something that can be protected against? Are there hedging instruments? Or is it the kind of thing that happens so quickly, even if you were hedged you wouldn't be correctly hedged?

MR. QUINN: Well I think they can always hedge. I think the difficulty for them, and we have phone calls with state regulators every month, and it's something we talk a lot about on our phone calls, especially in 2008 when you had a very clear it's always going up or it's always going down, trying to figure out when to buy, if you're trying to buy on a trend, it becomes very difficult. And at some point at the beginning of the summer in June, it was hard to figure out why gas prices were what they were.

So there's always a vehicle to go out and hedge with, but whether it's going to be prudent and your state regulator is going to say that was a good idea to hedge in June of 2008, you cut off the real top, that becomes a really hard problem.

COMMISSIONER KELLY: Because you can't predict.

MR. QUINN: Because you can't predict. And they are having the same problem right now. You know, it probably looked like a great idea to hedge in January, but prices are even lower than they were in January. So trying to time it is a difficult thing to do. And from the state regulator's perspective, the kind of guidance they give on

prudence, our conversations suggest that it's not easily done. I mean, the financial instruments are there; it's the regulatory side that makes it hard.

COMMISSIONER KELLY: Well thank you. And thank you for the development of the information. I also want to pass on that as I travel in the state regulatory circles at NARUC, how much state regulators appreciate the work that you do and the outreach that you do with state regulators. Thank you.

CHAIRMAN WELLINGHOFF: Thank you, Suedeen. Marc.

COMMISSIONER SPITZER: Thank you, Mr. Chairman.

I find interesting the relationship between LNG and domestic production. It seems to be a one-way street; that the LNG imports to the U.S. can depress production potentially, but because the international factors drive LNG it doesn't work the other way around. Domestic production won't have an impact, or presumably a negligible impact.

There was a recent announcement of an agreement between an exporter and a facility on the West Coast, the Cote d'Ivoire, for a substantial long-term. I think it was a 20-year contract. And there was criticism from the producers.

Given that these liquefaction facilities have been constructed, tankers have been leased, so the fixed costs have been absorbed and the cost of production in these

exporting regions is fairly low, it seems they're going to proceed with continuing to enter into these agreements.

What is your view as to the long-term impact on U.S. nonconventional production given the relatively higher costs that you describe?

MR. QUINN: He's going to make me make mistakes and think about his answer while I talk.

(Laughter.)

MR. QUINN: I think from our perspective what we've been focusing on is where the price cutoffs seem to be. Internationally LNGs would like any price they can get, but $3 seems to be about where they're going to stop supplying.

From the domestic production side, for some very productive basins it might be as low as $3.30. So something like the Hainesville Shale could be completely competitive with LNG, regardless of how much they bring. You know, they're both competing on about the same cost basis.

I think it is fundamentally a question of what the international kind of balance is. Right now we an attractive spot for LNG because global prices are depressed. That certainly was not the case for the last about a year, maybe a year and a half.

So whether we are predictably going to be a place that people can land LNG would drive somebody out of long-

term play, what we're starting to appreciate about the natural gas market is that once they identify a field that is productive, it is very much now a manufacturing process. If you drill a well where you get good production, the next well is going to be about as good. And you're learning enough along the way that your costs are going down.

And so for the unconventional gas plays, once identified it is very productive and the cost can be very competitive.

So for those types of fields, I am not sure that LNG will displace them.

COMMISSIONER SPITZER: The net result is an increase in aggregate supply.

MR. QUINN: Right.

COMMISSIONER SPITZER: So they--okay. And we had a decline in '08 in LNG imports. How much of that was due to the--you have the situation in Japan with the nuclear plant down, and there were substantial imports. How much of that was a temporal phenomenon short-term?

MR. QUINN: Well I think because Asian LNG prices are priced off of crude oil, and there was a lot of extra demand in Asia because of Japan having a nuclear outage, some of those were by definition temporal. I mean, the nuclear outage is gone, and part of the reason there is less demand in Asia is because they don't need to replace the

largest nuclear unit in the world.

The crude oil price and the relationship with the natural gas price, the degree to which that was temporal or not and whether the crude oil grew faster than natural gas did, I think we have seen lately crude oil has kind of been going up a little bit while natural gas prices continue to fall. That separation might continue. But it just depends on kind of the combination of market forces taking place in both markets at the same time.

COMMISSIONER SPITZER: From the consumer's perspective, given that the domestic supply will continue--Hainesville you alluded to was one of the lower cost plays--there are substantial consumer benefits to continued attention to LNG imports, given the potential for global low prices in Asia resulting in $3 gas coming into the U.S. Notwithstanding the new technology and the continued plays in the U.S. on the domestic side.

MR. QUINN: My sense is that more supply is always good. Our concern--and that's what we kind of tried to address--is the forward curve right now for natural gas gets it back to the $6 to $8 range pretty quickly, basically by next winter.

So the forward curve for gas suggests that domestically to keep producing. The concern would be if the forward curve was depressed for a long term whether you

would lead to a boom/bust cycle.

LNG would have to be, though, consistent, you know, clearly coming in year after year to affect the forward curve out to the point that domestic production would permanently be displaced.

COMMISSIONER SPITZER: And that is not likely, given the global demands.

MR. QUINN: At least that's not what the forward curve says right now.

Do you guys have anything else on LNG? Correct my mistakes.

MR. PETERSON: Just a couple of additional points. Some of the new LNG terminals that have entered service are in parts of the North American Gas Grid that at times can be very congested, especially in the winter and reflect very high basis value.

So the Kenneport facility that will be coming on line soon, the Northeast Gateway facility that's received a couple of cargoes. There's a new facility that should open near Boston soon, as well as the Cote d'Ivoire facility on the West Coast, they all are kind of in downstream parts of the grid that at times reflect high transportation differentials, and there's great value to having the optionality to be able to put gas into those locations, as well as on the Eastern Seaboard at the expanded Elba Island

and Cove Point facilities, as well.

So despite the huge increase in domestically resourced natural gas that has actually acted to push out some Canadian gas and minimize temporarily the amount of LNG we're bringing in, LNG can be and will be an important resource for the U.S., especially in downstream markets. But even in the Gulf Coast terminals I think what we will see is there's been a unique set of circumstances where we've had extreme tightness in global markets that created unprecedented $147 crude oil prices translated into $25 per million Btu gas prices in Japan.

I mean, the U.S. is not going to compete away those resources. Now that the crude markets have been reset, and we've added more shipping capacity, there's a huge amount of liquefaction faction capacity that will come on line by the end of the year, you know once some of these lumpy investments that have been made play out, we get to a new equilibrium I suspect the U.S. will be able to track LNG at much lower prices. And some of these extreme phenomenon where we've seen U.S. LNG imports in a single year cut in half because of Asian power demand or, you know, dry hydro years in Spain, I think we will see a rebalancing of that and maybe a more consistent level of imports than what we saw last year.

COMMISSIONER SPITZER: Okay. Capacity releases

have already been discussed briefly. Were you surprised by the numbers in capacity release, that there was not greater usage of that?

MR. REICH: Well to a great extent this is the initial few months of the program in terms of whether it's premium releases, and to a certain extent those months coincide with winter months, which make it a little more--a little less likely the capacity available to be released.

On top of that, based on our conversations with our audit team, we understand that a lot of the one-year capacity releases that occur in the context of the asset management agreements occur near the end of the gas year for the future gas year, which wouldn't have been captured in the data that we analyzed.

So was it lower than we would have expected? Maybe a little, but by the same token I think we are still a little early on in people's experience.

COMMISSIONER SPITZER: I did see a survey, or a study that suggested that the LDCs were not benefitting as much from the program as has been expected. Are you familiar with that?

MR. REICH: Yes. We saw that study, too. Looking at the data we looked at, we did not get that sense. They were certainly participating a third or more I believe of the releases that occurred, that have occurred in the

first six months of the availability of releasing at or above the cap were released by LDCs.

Once again, there may be some limitation in the fact that most of the experience for the program has been late--has been fall and winter where LDCs are less likely to be releasing than they would be during the spring and summer.

COMMISSIONER SPITZER: So then the next set of data for this season you would expect to perhaps see more LDC participation?

MR. REICH: We are continuing to monitor the situation and as the information comes in we will continue to look at it and analyze it.

COMMISSIONER SPITZER: Thank you. My final question is: I've seen rival studies, competing studies I suppose, on the question of the impact of greenhouse gas legislation on natural gas prices.

One study suggests a lack of impact, and the other suggests a fairly dramatic price increase due to a move from coal to natural gas.

Have you looked at those studies? And do you have any conclusions on the impact?

MR. QUINN: We haven't--the bottom line is we haven't looked at those studies closely. We have been more focused on shorter term issues related to natural gas

displacing coal generation, but we certainly have seen that in the Southeast and to some extent in the mid-Atlantic.

We think we have seen a decent amount of displacement of natural gas, or natural gas displacing coal in the Southeast, and natural gas prices continuing to fall, but we haven't looked any more than kind of what's been happening lately.

COMMISSIONER SPITZER: Thank you.

CHAIRMAN WELLINGHOFF: Thank you, Marc. Team, thank you again for the presentation.

Madam Secretary, our next presentation item.

SECRETARY BOSE: Thank you, Mr. Chairman.

The next item for presentation and discussion this morning is C-1 concerning Docket No. CP95-35-001. There will be a presentation by Richard Foley from the Office of Energy Projects. He is accompanied by Terry Turpin and David Hanobic from the Office of Energy Projects, and Katherine Zenion from the Office of the General Counsel.

MR. FOLEY: Good morning, Chairman and Commissioners.

In Item C-1, EcoElectrica seeks to amend its Natural GAs Act Section 3 authorizations in order to increase the existing sendout capability of its LNG terminal in the Commonwealth of Puerto Rico.

In 1996, EcoElectrica was authorized by the

Commission to site, construct, and operate its LNG importation facilities.

In 2000, EcoElectrica began operation of its lNG terminal and its affiliated 461-megawatt electric cogeneration facility.

Now EcoElectrica seeks Commission approval to install additional LNG vaporization equipment at its LNG terminal in order to deliver natural gas to the Puerto Rico Electric Power Authority for the Power Authority's Aguirre Combined Cycle Power Plant.

After receiving local approvals in 2008, the Power Authority began constructing a 42-mile-long natural gas pipeline from EcoElectrica's LNG terminal to its electric generation plant.

The Power Authority will own and operate this pipeline. The Power Authority also modified the electric generation plant to include combined cycle generation units capable of burning natural gas.

Before 2000, Puerto Rico was nearly fully dependent on fuel oil for electric power generation. However, now they are fuel diversified using about 74 percent fuel oil, 13 percent natural gas, and 13 percent coal.

Approval of Item C-1 will allow the Puerto Rico Electric Power authority to further diversity fuel sources

with the additional access to natural gas from EcoElectrica.

In the study of its part of this project, the Power Authority recognized the significant air quality improvements of switching from fuel oil to natural gas and found that significant reductions in the emission of carbon dioxide, nitrogen oxides, sulfur dioxide, particulates, and volatile compounds are expected. If the power plant operates using the expected amount of natural gas, the carbon reduction would be 200,000 metric tons per year.

The draft Order grants EcoElectrica the authority to construct additional facilities at its LNG terminal under Section 3 of the Natural Gas Act, subject to certain conditions.

This concludes staff's presentation. We would be happy to answer any questions you have.

CHAIRMAN WELLINGHOFF: Richard, thank you for your presentation and thank you, staff, for your work on this case.

I also want to thank Commissioner Moeller for suggesting that this be a presentation item. I think this is a very significant case and I am pleased to vote for it. I am very pleased with the local pollution reductions and air quality increase with this addition of this infrastructure facility, and also the global carbon reductions of 200,000 metric tons. That is very

significant.

Phil.

COMMISSIONER MOELLER: Thank you, Mr. Chairman, and thank you for the team presentation. I appreciate the fact that you allowed us to discuss this briefly.

We don't often talk about Puerto Rico, but they are a significant part of our economy and of our Nation. We do have jurisdictional authority here, and mainly this is a case where the LNG terminal that existed and the expansion does have significant environmental benefits. It is part of what we need to discuss when we talk about LNG. I will be happy to support the Order.

CHAIRMAN WELLINGHOFF: Anyone else?

COMMISSIONER SPITZER: Just, had FERC not sited this facility in 1996 we wouldn't be here, and it has operated safely and profitably and for the benefit of the ratepayers ever since.

CHAIRMAN WELLINGHOFF: Thank you. Suedeen?

(No response.)

CHAIRMAN WELLINGHOFF: Madam Secretary?

SECRETARY BOSE: The vote begins with Commissioner Moeller.

COMMISSIONER MOELLER: Aye.

SECRETARY BOSE: Commissioner Spitzer.

COMMISSIONER SPITZER: Aye.

SECRETARY BOSE: Commissioner Kelly.

COMMISSIONER KELLY: Aye.

SECRETARY BOSE: And Chairman Wellinghoff.

CHAIRMAN WELLINGHOFF: Aye.

Thank you again for your presentation. If there's nothing further, that is the end of the meeting. Thank you.

(Whereupon, at 11:30 a.m., Thursday, April 16, 2009, the 946th Open Meeting of the Federal Energy Regulatory Commissioners was adjourned.)