UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

STATE OF THE NATURAL GAS : PL04-17-000

INDUSTRY CONFERENCE :

STAFF REPORT ON NATURAL GAS : AD04-11-000

STORAGE :

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Hearing Room 2C
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C.

Thursday, October 21, 2004

The above-entitled matter came on for hearing, pursuant to notice, at 9:10 a.m.

PRESIDING:

BERNE MOSLEY, OEP, presiding

P R O C E E D I N G S

(9:10 a.m.)

MR. MOSLEY: If we should start taking our seats. The panelists should probably wait until after the keynote speaker to come up to the panel.

Good morning, Chairman Wood, Commissioners, and the public. I'd like to welcome everyone to today's State of the Natural Gas Industry Conference. My name is Berne Mosley, Director of Pipeline Certificates in FERC's Office of Energy Projects. This is the third annual event that we had for the State of the Gas Industry, and the purpose of today's event is to engage industry members and the public in a dialogue about policy issues facing the natural gas industry today and the Commission's regulation in the industry of the future.

Today we'll hear from very wise and interesting people, raising different issues on different aspects of the industry. What we would like to do is start with our keynote speaker, and then follow it up by the panelists, the first panel.

We'll have three panel sessions. In each session, at the end, there will be an opportunity for the staff, the Commissioners, and the panelists to talk to each other and question each other. Then there will be a public Q&A session. I would ask that you step up to the microphone, introduce yourself and your organization, and proceed with your question. At the very end, after the third panel, there will be an open public forum for anyone who has signed up. I encourage you if you have not done so so far. This is only for the public forum session to go and sign up at the front door. I believe the sign-up sheet is. And you'll have an opportunity in the public forum session to speak.

Before I introduce the speaker, Chairman or Commissioners would you like to make any statements?

CHAIRMAN WOOD: Thank you, Berne. I appreciate your setting this up. I appreciate the parties that have shown up. Just to put in context, this is the Third Annual State of the Gas Industry Conference that we've held. Each year, we have picked an item or two of interest. In past years, we've talked about open access on LNG import terminals, gathering policy, pipeline rate issues. Last year, we talked about gas quality and the National Petroleum Council Report. This year, I think based on really what the Commissioners have been hearing from within the industry, out on the road and here in our offices and what staff have picked up, is that the storage issues are really ripe for further discussion. We have found these forums to be very helpful ways of having policy discussions that may or may not lead to changes in the Commission's direction, but it's a much more expedited method to deal with that than some of the more traditional APA methods we've used in the past. So, I would encourage parties to be real frank and open about their advocacy for their position and encourage parties to be very frank about the views of the other panelists that they may agree with or may not agree with. That really helps us ascertain some directions that we may want to move forward on in this real important industry.

As you know, it's been under a lot of stress lately, both on price and on deliverability, because it's such an attractive product to customers. So, we want to make sure that as the regulators we're keeping pace with the changes that we need to make. So, please know that our minds are open. We've tried to set up panels that are very diverse, and represent some views. And I think as staff appropriately ask some nicely provocative questions setting up this conference that I hope everybody will tee off today.

We're here. We're very interested. Suedeen will be here in just a second. We look forward to a very enjoyable and informative day. Thanks, Berne.

MR. MOSLEY: Thank you, Chairman.

COMMISSIONER KELLIHER: I just wanted to follow up on what Chairman Woods said: that these meetings, the State of the Gas Meetings, are not just gabfests. They have resulted in concrete policy changes in the past, and that's going to be the case today. The Commission is concerned about price volatility and promoting expanded storage capacity and more efficient use of capacity will help. So, some of our policies goes back. The equitable policy goes back to 1986, and its origins go back to the '70s. It seems storage is being used differently, and it is appropriate to look at changes in policy to reflect the different use of gas storage capacity. So, I look forward to the conference. Thank you.

MR. MOSLEY: Thank you. To introduce our keynote speaker, I'm sure most of you know him. He was appointed to the Public Utilities Commission of Ohio in February 1998 and reappointed in March 2003. He was appointed by the U.S. Secretary of Energy, Spencer Abraham, to serve on the National Petroleum Council you heard about earlier. He serves on the State of Ohio Security Task Force, and was the coordinator for the Ohio Y2K Reliability efforts. He's chairman of the National Association of Regulatory Commissioners' Gas Committee, and serves on the NARU Ad Hoc Committee on Electric Restructuring and the Ad Hoc Committee on Critical Infrastructure. He serves on the Gas Technology Institute's Public Interest Advisory Council. He's also the official representative for Ohio to the Interstate Oil and Gas Compact Commission, where he serves as vice chairman. Chairman of Energy Resources Research and Technology

Committee. Chairman of the Pipeline Infrastructure Task Force, and vice chairman of the Legal and Regulatory Affairs Committee. Please welcome Commissioner Donald Mason.

KEYNOTE REMARKS

COMMISSIONER MASON: Good morning. It's a pleasure to speak to everyone this morning. As I indicated, my name is Don Mason, Commissioner of the Public Utilities Commission of Ohio, and Chairman of the Gas Committee of NARUC.

NARUC appreciates the opportunity to provide comment to this technical conference, as we have at other conferences.

As Chairman of the NARUC Committee on Gas, I wish to thank the Commission for the opportunity to make these remarks on important natural gas issues. NARUC appreciates the Commission's endeavors to highlight the importance of a robust natural gas market through its initiatives regarding enhancing reliable gas price reporting, enhanced storage reporting, as examined by the technical conference two weeks ago, and continued investment in the infrastructure, particularly storage, which is the focus of today's conference.

First, I would like to begin with the observation that there should be recognition of the importance of a healthy natural gas market, particularly in light of the increasing interdependence of natural gas and electricity markets, including potential impacts of higher natural gas prices on electricity rates. There has been an increasing gap between natural gas demand and domestic production, resulting in American natural gas prices being among the highest in the world. The recent rise in natural gas prices raises concerns for all industry participants--producers, suppliers, marketers, and especially consumers.

In addition to high prices, volatility is another significant challenge facing the natural gas industry and its customers. Market pressure will continue because of continued growth in natural demand and limited growth in natural gas supply.

Government policies that foster increased supplies of natural gas could benefit consumers by exerting downward pressure on natural gas prices. Those government policies that foster the development of a balanced natural gas portfolio could benefit consumers by providing greater price certainty. Such a balanced portfolio should include and could include elements of on system and off system gas storage.

Another key challenge to energy availability is an adequate natural gas pipeline and distribution system to provide for the ever-increasing demand across the country. Increased storage and pipeline development as part of a total energy plan are positive response to these challenges. Federal and state regulators can help in this regard by promoting initiatives for the development of gas storage and pipeline facilities. As this Commission's underground natural gas storage for pipe found, the market's method for evaluations of storage and the relation to the cost of new development is a factor hindering development of natural gas projects. The reports concludes long-term market price signals appear to be weak for new storage development. I would add that the development of gas storage is hindered, in part, by the marketplace, because some of its participants dislike long-term capital investments without large returns. I believe the Federal Government should study the incentives necessary to create investment in storage fields, whether it is in salt caverns or facilities closer to the end user.

We have discussed incentives to construct pipelines in the past. Future discussions will focus on the type of incentives necessary to encourage investments in storage and pipeline facilities necessary for future development.

In addition, unnecessary regulatory burdens should be examined and eliminated.

Finally, for the use of creative approaches to encourage storage development, such as alternative price methods that recognize the levels of risk. In my work as the outgoing Chairman, we have supported gas regulation by the states. Differences in geology, climate, and economic factors can be adequately considered at the state level. In this regard, the one size fits all nature of some Federal laws and regulations cannot efficiently deal with the diversity of individual states and will act to discourage domestic production.

I encourage the various state governments to support natural gas production in their respective states. For example, according to the Energy Information Agency, EIA, the northern and central Appalachian region, which includes Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, West Virginia, offer just over 10 TCF of proven conventional gas reserves. Yet, EIA and the U.S. Geological Survey indicate that there's another 13 TCF of additional recoverable reserve in this area dual to coal bed methane alone. It should be recognized, by the way, that coal bed methane is important because it provides eight to 10 percent of our nation's domestic supply production.

Another 20 plus TCF may be recoverable from the black shales of this region. I'm referring to the Appalachians. These estimates do not include the deeper potential of risk base for recent discoveries in the Trenton Black River have shown huge reserves, and these huge reserves lie very close to the ports of consumption, the northeast.

Support for research may help delineate and fully characterize these resources as needed, as well as incentives for bringing production to market. In my capacity as NARUC's Gas Committee Chair and as a state regulator, I encourage state commissions and other policy makers to export the expansion of gas storage and pipeline facilities in their regions. Wide support of gas storage and pipeline development is the best -- what is the best approach will certainly depend on regional and local issues, preferences, and conditions in order to tailor them to each specific state goal and needs. As states and regions adopt these initiatives, regulators and industry together can combat high natural gas prices and gas price volatility in their respective regions, resulting in benefits for our industry and especially to the consumers.

In conclusion, both Federal and state treasuries benefit substantially from helping the natural gas industry; thereby, the government's share of developing and implementing incentive programs to encourage domestic gas exploration and production, as well as worthy infrastructure development.

I want to thank you again for this opportunity to represent the regulators across our country.

MR. MOSLEY: Thank you, Don. I really appreciate your remarks. Mr. Chairman, Commissioners, do you have any questions for Commissioner Mason?

(No response.)

COMMENTS ON STAFF REPORT AND STORAGE DEVELOPMENT POLICY

MR. MOSLEY: Thank you very much.

Now, we're beginning to move to the first panel session. I should probably quickly introduce staff here, so you'll know who we are when we speak. We all have name tents but some of you in the back can't quite see. Start it with Rich Foley, N.G. Schall, Tom Pinkston from OMOI, Jacqueline Holmes from OGC Projects, Ed Murrell from OMTR, Steve Harvey from OMOI. As I mentioned, I'm Berne Mosley, Director of Pipeline Certificates. We have John Carlson, OMTRA's West, Bob Flanders, OMOI Energy, Paula Crunkilton, and had some representatives from the Chairman and Commissioner's Office. We have Andrew Soto. We have Miles Nichols. We have Maria Vouras.

Just a quick note. Before we call this panel, I would like to remind everyone, both in the Q&A session and in the panel discussions, not to, of course, discuss any pending cases that we have here at the Commission. If the first panel can please come up to the table.

(Pause.)

I'd like to introduce the panel. I'm ready to introduce them in the order in which they will speak. I'll begin with Richard Daniel, President of EnCana Gas Storage. Matt Morrow, President of ENSTOR. Ryan O'Neal, Vice President for Development, Sempra Energy. Jim Bow, from Dewey Ballantine and Red Lake Gas Storage. Mark Cooke, Principal from SGR Holdings. Don Zinko, Vice President of Business Development of Western Pipelines and EP&G Marketing and substituting for Carl Levander. Sharon Wika.

Mr. Daniel, if you'd like to start.

MR. DANIEL: Thank you. My name is Rick Daniel, President of EnCana Gas Storage, Inc., a subsidiary. Our interest in that session is obviously that of an independent gas storage operator and development, but also that of one of North America's largest gas producers, which has a vital interest in a growing and efficient gas market and a dependable infrastructure. It was almost exactly one year ago today I think that I was in this room with the National Petroleum Council presenting to the Commission the conclusions of the storage section of the 2002 NTC report. I think the quality of the discussion on storage issues within the industry has improved quite a bit in the 12 months since then. Certainly, the Commission's staff report are further positive steps in the process. Hopefully, we'll all leave here today with more additional insights on this already complex part of the gas industry.

For my part, I want to use my few minutes at the mike to try to expand a little bit on the concept of effective storage capacity, which we addressed in our written remarks. I've also just a few very brief comments on some policy issues. How much storage capacity or working gas capacity do we have in the U.S.? That's the really difficult question. It sounds like a simple question that should have a simple answer. But it isn't. As the staff report clearly outlines not only is there no agreement on the correct answer, but there's an astonishing range of answers given the EIA estimates 4.4 to 4.7 TCF. The Office of Fossil Energy, about 3.9 TCF of working gas capacity, and the staff report says they estimate 3.5 TCF of a practical working gas capacity and another 200 to 500 BCF of potential that could be reengineered and used.

What does the 3.5 TCF of practical capacity really mean? Perhaps it's intended to be the same as what I define as effective working gas capacity in our written summation. I define that as the amount of gas inventory that can be practically built up during an injection season and depleted during one withdrawal season. That's what I'm defining as effective working gas capacity. To be effective, it has to be accessible under reasonably foreseeable market conditions, so capacity, which is in the wrong location or which can only be fully utilized under implausible assumptions on the timing of the market's demand for injection and withdrawal capability, does not really affect the capacity.

When the staff reports says there's three and one-half TCF of working gas capacity, what does it really entail? Is it simply saying that we can build stated working gas or inventory levels to 3.5 TCF? That seems like a reasonable estimate after all. It looks like we've built over 3.3 TCF this year. And, although getting another 200 BCF in might have been a challenge, it is not unreasonable to assume that it can be done. But to meet my definition of effective working gas capacity, we would also need to be able to draw inventories down to zero to say that you had working gas capacity of 3.5 TCF to draw down to zero if required by winter demand.

To put things in perspective, it wasn't until the mid 1990's that we demonstrated an ability to cycle even more than two TCF in a year. And it's only been in two years very recently, the year 2001 and the year 2002 to '3, that we approached two and one-half TCF injected and withdrawn. Two and a half TCF. And those two years extreme seasonal price differentials that occurred as, of course, the end of the injection season and again at the end of the withdrawal season suggested that there was an unmet demand to store and withdrawal more gas. There would certainly be price incentives to store more gas in more of the areas if you could have. So, the price variability in those years, combined with anecdotal evidence from discussions of other storage operators, leads us at least to conclude that the growth in the gas market and the growing seasonality and weather sensitivity of the market are pushing us closer to the limitations of the current infrastructure, even in trying to store and withdraw two and half TFF. Unfortunately, there is no easy way to estimate what I'm calling effective capacity for one facility, let alone for the industry as a whole, because it is based not just on the physical capabilities of the facilities, but on how these facilities relate to the market. All we can do is observe how the market reacts for the next few years as we try to store and withdraw larger quantities of gas. I freely admit that there are plausible alternative interpretations of this data which could lead to higher estimates of effective working gas capacity and which might suggest that we can handle significantly more than the two and a half TCF we have cycled in recent years.

Unfortunately, we may not get a better handle on this until the system is severely tested.

In the meantime, in the face of these uncertainties, it would be prudent regulatory policy to encourage, but not to mandate, the development of additional capacity to ensure that there are no unnecessary obstacles to the development of new capacity and to the optimization of the capacity already in place, while allowing the decisions on when, where, and how much capacity is developed to be made by the market actions of storage customers and storage developers. In particular, one proposal put forward in the notice for this conference that of allowing regulated cost recovery for the creation of an uncommitted reserve margin should be rejected as counterproductive. I know that this will be the subject of more detailed discussion by the next panel, but allow me to just very briefly state EnCana's reasons for opposing the concept.

I know, from years of developing storage capacity and marketing storage capacity, just how difficult it is to determine where to build capacity and what injection and withdrawal profiles to build that will meet the needs of customers now and in the future, capacity which the customers can access in a manner that meets their load profiles. It's a complexity that can best be resolved through detailed discussions between customers and developers, leading to some combination of customer commitments to a multi-year contract and or a degree of at-risk capital committed by a developer. Trying to decide these issues through the regulatory process in the absence of that sort of market discipline is likely to result in the construction of capacity that meets nobody's needs, essentially stranded capacity. What the market needs is more effective capacity, not more capacity on paper. You might ask why not do it all? Why not encourage at-risk independent storage development, encourage approval, approve the expansions of customer service capacity, supported by market commitments, and approve construction of uncommitted reserve capacity. Why not do it all?

Unfortunately, you can't have it both ways. The first way to kill incentives for storage customers and storage developers that meet commitments to developing new capacity is to see just that once they have built the new capacity, you may encourage a competitor, perhaps the pipeline to which your facility is connected, to build excess capacity at no shareholder risk. You can't ride these two horses at the same time.

We encourage the Commission to clearly from a pro-market policy on storage development, and then as an industry we can get on with developing and optimizing facilities to increase our effective working gas capacity. Thank you.

MR. MOSLEY: Thank you, Rick. I would like everyone to save their questions for Rick until after we've gone through all of the panel members. Then, you can ask a particular panel member a question about his or her presentation.

Next we have Matt Morrow from ENSTOR.

MR. MORROW: Good morning. I'm Matt Morrow, the President of ENSTOR Operating Company.

I'd like to start by thanking the Commission for scheduling this conference and giving us the opportunity to speak on several topics, including the development and ongoing commercial operations of natural gas storage. For those unfamiliar with ENSTOR, we're an independent natural gas storage company. We have operating facilities in Alberta, Canada, and Cady, Texas, one of which, Cady, was actually granted market-based rates this past year.

In addition to these facilities, we're currently considering development of several regions across North America, and planning to triple the size of this business over the next 10 years. ENSTOR has -- got a power company -- our business model is based on the idea of creating a hub by offering services that facilitate the trading of natural gas and develop liquidity in the market. ENSTOR offers several services, from storage parking, loaning, wheeling, title tracking, all of which are designed to help create liquidity. The one thing we do not do is engage in the buying and selling of natural gas. We believe the service providers should only provide services.

I plan to discuss three topics this morning: the role of the independent storage operator plays in the marketplace and the regulatory obstacles they face; the role Cana (sp?) should play in helping to promote creative storage services and additional storage development; and why first traditional tests are authorizing market-based rates may no longer be appropriate for storage providers generally and for independent gas storage providers specifically.

Independent storage developers have played a key role over the last decade, adding over 75 percent of the incremental storage capacity to the system. They have developed new and innovative services, have risked their capital. They've stepped up to satisfy the customer. Price volatility concerns, as the FERC staff report correctly noted, the need for additional gas storage is becoming more evident, with long-term natural gas prices hitting all-time highs, volatility increasing, and North America, for the first time, becoming more reliant on foreign services of supply such as LNG. An estimate 35 to 50 BCF of new storage capacity need to be added per year to keep pace with the fluctuating demand for natural gas.

It appears that independent storage operators will continue to be needed to accommodate the forecasted increases in the future. When evaluating the list of proposed projects, independents make up an overwhelming majority.

ENSTOR and other independent developers face significant obstacles. We have increased development costs, a lack of long-term contractual commitments, and other regulatory constraints.

Unless and until such policies are changed or market risks are otherwise mitigated, customers will be continually and unnecessarily denied the benefits of natural gas storage. I mentioned increased development costs. Costs are on the rise with natural gas prices being above $6 for the summertime. The cost of cushion gas has skyrocketed. To exacerbate that problem, the price of steel has gone up over 150 percent over the last six months alone. That, in turn, has increased the cost of line pipe compressors, valves, tubulars, all of which are very important for the development of storage. I understand this is out of the Commission's control, but I wanted to at least identify it as an issue that we're facing.

Lack of long-term contractual commitments. This issue has been around for a long time for independent natural gas storage developers. It's been around for really over a decade. It's really been accentuated with the collapse of the mega marketer. Independent storage operators like ENSTOR have managed to mitigate such risks with one- to three-year contracts, and with the availability of market-based rates. As the value of storage has varied widely, it's gone from $0.20 to over a dollar and back forth over the last 10 years. The need for market-based rates has proven itself time and time again.

Operators like ENSTOR must have the rate flexibility to charge higher rates at periods of high demand and lower rates in periods of low demand in order to justify the project's long-term economics. Otherwise, investment capital will be redeployed.

ENSTOR and other independents also face significant hurdles in development due to their dependence on connecting pipelines. Storage customers are rarely located near the facility itself. An effective storage service depends on the availability of adequate transportation.

As I mentioned, we as a storage operator do not buy the gas. We do not sell the gas. Thus, we do not have title to the gas. Unfortunately, the Commission's open access requirements would not apply to the independent storage operator due to the shipper must have title rule, which many times precludes us from being able to provide services to a customer where they're most needed. This makes the independent operator dependent on interstate pipelines and puts us at a disadvantage.

Moving on to the second topic of hub services. Natural gas storage facilities are storage hubs that have been helping create liquidity since their inception in the early '90s. They provided services that I mentioned, like parking, loaning, wheeling, title tracking, all the time to bring as many counter parties to the table and to make trading as easy to do as possible. So, and still we'd like to see the hub services model expanded that meets for its support to make this happen.

Specifically, we'd like the Commission to consider granting storage operators the ability to enter into transportation and storage arrangements with third-party pipeline and storage companies so that entities like ENSTOR can compete fairly with larger interstates and with the natural gas marketers and traders who compete with us in the grey market. These types of services are unprecedented and would likely require waivers of the Commission's shipper must have title and the capacity release rules. However, by leveling the playing field and eliminating the advantages of affiliated storage operators have, adoption of such a pro-market policy will allow independents to begin introducing innovative services and will clearly make the transportation grid more efficient and more responsive to the needs of customers.

ENSTOR offers two such products, both of which are described a bit more fully on a slide. The first requires storage capacity with interconnected pipelines that utilize that capacity in junction with stored facilities to offer the services to LDCs, power plants, industrials at their location.

The second hub-to-hub transfers would allow customers to inject ES in storage facility A and withdraw it from a different one. For example, inject gas in Texas and pour it out in Ohio. The storage rights at both locations and with minimal transportation required, the operator can move gas from point A to point B on a continual basis but offer the services to customers on an as needed basis.

Finally, concerning the market based rates. The proper assessment of market power for natural gas storage, ENSTOR would assert that new natural gas storage facilities are not able to exercise market power for two reasons. One, adding flexibility via adding a new storage facility decreases the likelihood that any party could exercise market power in the area. Number two and more importantly, the natural gas storage business precludes the operator from the ability to manipulate price. The first point which was mentioned in the Commission's staff report is that it seems counter intuitive that a party, particularly an independent, that gets customers more service choices and better gas pipe mitigation tools and new storage facilities could exercise market power, especially in regions that are already operating in an efficient manner. When considering that point and adding to the fact that a natural gas storage business is by nature an optional service for the customer, and once the customer holds that option, to make delivery it seems unlikely that the storage facility itself could move prices upward. The fundamental differences between natural gas storage and transportation help to illustrate the point. Gas pipelines are designed to give a gas from point A to point B and withholding that capacity from the market has proven to drive prices up. Natural gas storage facilities to not have that same power. Storage is designed to hold gas and move it from one time period to another. A storage facility cannot hold back delivery of gas because the operator does not own the gas. If the capacity is unsold, the facility has no gas in it to make deliveries during peak times.

As noted above, pricing schemes short of market-based rates provide too little flexibility and shift too much risk to independent storage operators. For this reason, ENSTOR or just the Commission to seriously consider granting independent storage operators blanket market-based rate authorization subject to periodic review. The idea that cost-based rates are a necessary safeguard against the exercise of market power and market manipulations by natural gas storage operators is not well taken, and we believe not supported by the realities of the independent storage business.

In closing, I'd like to reiterate the three points. ENSTOR believes the United States needs additional storage development to manage its natural gas system and its growing reliance on foreign supply. We believe to ensure the commercial viability of storage, FERC should allow and encourage innovative services and waive to no pools (sp?), like shipper must have title that are preventing independent storage operators from offering customers value-added products and from competing with larger interstate pipelines.

And finally to promote natural gas storage, FERC should endorse a general waiver for independent storage developers to be granted market-based rates.

Thank you for the chance to contribute. We look forward to working with you in the future.

MR. MOSLEY: Thank you, Matt. Next up is Ryan O'Neal from Sempra.

MR. O'NEAL: Thanks very much. Again, I want to just reiterate what I've heard previously. We appreciate the Commission's taking the time and interest in natural gas storage to take input from the market. This is the kind of event that actually helps foster sort of the growing business we're all trying to achieve.

Sempra Energy is a Fortune 500 energy service company. In '03, we had about $8 billion in revenue. Sempra Energy, International, one of the subsidiaries that I work for, is involved with transportation, storage, and distribution of natural gas throughout North America and Latin America. At Sempra, we have several pipeline storage projects. Here in the U.S., as well as in Mexico, we have one operating facility--one on permitting and one that we hope to file soon. And we've looked at storage throughout the U.S. in areas where there is active storage, and where there's actually none at the moment.

One of the things that's driving us as we look at the market is with the coming LNG wave, if you will, we believe that storage is going to be in higher demand, and we think that storage opportunities are going to increase. That's one of the reasons that we're so bullish on the market itself.

Looking at some of the background that's gotten us to where we are today. One of the things that we've looked at is that FERC has been using the pipeline model and trying to apply that to the storage concept, and I really don't think it's a fit. We're talking about a paradigm shift that's occurring where a new approach is going to be needed in order to try to regulate if you want to go down that path, regulate the storage market. As we say, pipelines are contracting on a long-term basis as the owner of assets and the pipeline market. It's quite different to look at 10 to 20, 25-year contracts, as opposed to the storage market where we're looking anywhere from one to five years. And on average, maybe you're looking at three-year terms. So the risk profile that a storage project has is inherently different and much riskier than a pipeline.

Another thing you have is that the traditional cost of service rate mechanism does not allow a risk adjusted return that would warrant spending the kind of money if you were again given cost of service rates. And I think that the uncertainty that that has on storage developers in itself may drive developers not to look at storage in certain areas because why would you risk all of your capital in turn to be granted cost of service rates and the risks associated with doing that and not being able to actually earn the return that's commensurate with the risk.

The challenge all of us have is that storage operators need to be able to realize the value of the assets that they own in markets where there may be volatility. And without stating the obvious here, storage is very region specific. There are certain areas where there's a great deal storage competing today and there's others where there's a lot less. But the dynamics that drive the individual decision are very specific to the individual area or the area that's being evaluated.

I want to state that Sempra fully supports market-based rates and believes this is the best option for both the customer and the storage owner and developer. This provides customers with more options that exist today, and it provides them the ability to chose whether they want to take that storage service. On face value, new storage must be priced at or under the alternatives in the market in order to attract any new customers. It is a choice. As we've heard, customers have the option, this is not a required service. This is an ability for them to select or elect to take that service in areas where FERC may look at it and say there isn't existing storage in the market; and, therefore, you'll be able to exert market power. We had a hard time with that concept. I know we'll probably hear a little bit more about that coming up.

FERC ought to be able to apply a discretionary analysis in this example. Why would new storage available to the market be deemed to have power when the market's existing and functioning today without it. Then you take the next step is where there's a market that has a little bit of storage: maybe it has two or three facilities, and you want to introduce a fourth. How is it that that introduction would then fall under the HHI analysis that you had market power and not be able to charge market-based rates.

Again, I think there's a discretionary analysis that might have to be looked. But if you're introducing options to the market, I don't understand how that would be exercising control. I think the fallback to that is you still have ability to exercise or look at customers' rates and complaints on a just and reasonable basis going forward.

We really believe that there's almost no circumstance that you could come across where market-based rates would not apply. But in light of the uncertainty, and I know that the amount of Commission change that needs to be done in order to reach that goal. We'd like to at least talk about what options might be reasonable for the FERC to decide that market-based rates are not an option.

Specifically, in certain areas where that may be the case, we think the Commission's idea of increasing the return on equity, accelerated depreciation, are actually lengthening the time between review of the revenue studies and cost studies is a good start. That is certainly going to help incent the market at least with the idea of moving forward and looking at alternatives where you might actually end up with a cost of service rate. Looking at term differentiated rates or off-peak, as they're described here today, under the revenue rate camp, I don't think those on their own really do that much. I think you're sifting the way the money is made, and I think indirectly you may end up kind of getting to the same point.

I do believe there's an alternative in between there which allows you to take some of the best of the term differentiated rate as well as the peak off peak concept and apply it in a slightly different manner. By doing that, what you could do is offer a storage service provider that's looking at signing a term contract. It's where someone wants to sign a contract under a one-year term to have market-based rates. For those that want to sign something longer term, the option's available. No one is making the customer sign a short-term contract. No one is forcing to sign up for any service at all. But it allows the storage operator to charge market-based rates when the market allows. And if it's something that the marketer or the person trying to buy the storage isn't desiring, where would be the harm?

In particular, these short-term contracts do not offer the long-term support for project fundamentals. They are also not going to probably be looked at by financiers as being reliable sources of income. Therefore, they'd be more speculative in nature. Short-term contracts, by nature, are probably looking to capture a spread basis that it's just like there's in the market today of $1.80. For all these reasons, we believe, this is a kind of approach that could sort of shift the way things are looked at, provide an alternative where cost of service may be necessary, because the Commission can't get around sort of its own rules, but give incentives to the market to actually go after it. We believe it provides long-term customers with little to no storage, and a viable alternative where you're still allowing the developer the opportunity to earn additional revenue.

In summary, we feel that storage projects have inherently more risk than is probably being granted in the cost of service rates, and the way it's being laid out. We believe market-based rates are the most desirable outcome for all involved. Remember: storage is a choice. It's an option for parties. It's not a requirement, as we've heard. We also believe where market-based rates are not granted, we should be increasing a return on equity or we should allow some flexibility in the way that shorter-term contracts are actually signed and negotiated. Also, just in sort of summary, while I'm sitting here, for Sempra International, and I do not represent SoCal Gas, and I don't represent San Diego Gas and Electric, so I have nothing to do with the utilities inside of California, but I do appreciate the opportunity to speak with you here today.

MR. MOSLEY: Thank you. Jim Bowe? Good morning. Jim Bowe with Dewey Ballantine, LLP, representing on this panel Red Lake Gas Storage Limited Partnership.

MR. BOWE: I'd like to thank the Chairman, Commissioners, and all the staff members for putting this program together, and especially -- Red Lake Gas Storage is a project that's probably better known than most projects, but that have not yet come to fruition. It is, as I think most people here know, a project company whose application for a certificate was denied or dismissed I should say upon FERC's denial of market-based rate authorization to the project. This, despite a preliminary determination, that the project would serve a market need and otherwise would be consistent with the public convenience and necessity. With two FERC orders denying market-based rate authority, plus the difficulties in the market that are well known to everyone here, including difficulties that have affected Aquila, Red Lake's current owner, you might say that Red Lake is down three games at this point.

(Laughter.)

MR. BOWE: But I'm here to say that being down three games is no longer outcome determinant.

(Laughter.)

MR. BOWE: And Red Lakes' year may be here, if not this year, then next year, depending on what the Commission does as a result of this conference. This really takes me to my first point, which will also be my last point. We need action to come out of this conference. I was pleased to hear Chairman Wood and Commissioner Kelliher mention that these sorts of proceedings can sometimes result in Commission policy changes. I was particularly pleased to hear Commissioner Kelliher say that perhaps it should result in a policy change, and I urge the Commission to come away from this conference and the aftermath, which will undoubtedly involve lots of paper, with a real resolution to move forward on any policy that provides some certainty in a market which desperately needs it. I will come back to that point at the conclusion of my comments.

My second point is not a surprise. It's going to be violently agreed by everyone I think on this panel and that is that FERC must adopt more flexible procedures for evaluating requests for market-based rates put forward at least by independent or what I would call merchant gas storage providers who are going to be new entrants into the storage markets.

As we have said in written comments that we submitted in this proceeding, the Commission needs to conclude that, as a matter of general policy, new merchant gas storage entrants should be permitted to charge market-based rates. The Commission has legal authority to do that. I'm, I guess, the lawyer on the panel, the one that gets paid for being a lawyer on the panel, and I will come back to that point and provide some legal authority for that proposition. But subject to a periodic review, perhaps some information filing requirements, and, of course, always subject to FERC's power to entertain complaints under Section 5 of the Natural Gas Act.

The Commission has the legal authority to permit the market to work. The staff report recognizes I think clearly that market-based rates are essential for merchant gas storage developers. And I think we've heard that from each of the panelists thus far. I know we'll hear it from the panels yet to come. I won't belabor the point. But storage operators need the ability to capture value as the market reflects value from time to time. Without this, few to zero developers will take on the enormous risks in a higher cost environment, such as Mr. Morrow mentioned of developing gas storage that is needed, whether you buy the Natural Petroleum Council Study, the INGAA study or something even more modest, such as the staff report. There is consensus across the board that additional storage is needed. Without the ability to capture the value that the market permits storage providers to capture from time to time through market-based rates, this development will be stunted if it happens at all. It's highly unlikely that without market-based rates, despite what I've said about being down three games, but with perhaps four to go, Red Lake will rise again. Red Lake must have market-based rates for the opportunity for its developer to realize value that the market will permit from time to time in order to justify the enormous risk involved.

As matters now stand, FERC's somewhat mechanical assessment of market power is a major impediment certainly for projects in the position of Red Lake to move forward. That's true of any projects that might be proposed for areas where there's a concentrated storage market or where there is not much storage.

These days, performing the market power analysis that the Commission has adopted for gas storage is a pretty mechanical exercise. We already know what the answer is going to be in the production area. We know what the answer is going to be in initial development. We know probably that tests will be passed for new independent, relatively small storage developers in the Northeast. Why go through the exercise? We know what the outcome is going to be. We also know that no one is going to pass the market-based rates screen adopted from the merger guidelines in the West or the Southwest. The Commission needs to move beyond that.

The irony is that the market power screen that the Commission currently uses is easily passed where there's plenty of storage, arguably where there's diversity of storage and perhaps where there's no need for storage, and easily flunked where there is the greatest need for new market entries. That strikes me as kind of intuitive, and it's now really a barrier to entry. It doesn't have to be this way. The current standards for evaluating applications for market-based rate authority based on the anti-trust merger guidelines are not inscribed on stone tablets. They were not brought down from the mountain. They are not the only means by which the Commission can lawfully look at the question of whether a base storage operator should be permitted to charge market-based rates. So, as a legal matter, the Commission is not bound to using the approach it's used so far. The Courts have recognized right up to the U.S. Supreme Court that the Commission is not obligated to follow any particular rate making formula. The Courts have affirmed that the Commission may approve market-based rates and may conclude that the market will operate to maintain rates at just at reasonable levels. It is entitled to engage in predictions that that is indeed going to be the case under the cases, and the Commission enjoys latitude in determining how to assure that rates will be limited to just and reasonable levels by market forces. I think the staff report recognizes this sort of common sense proposition. A new entrant, particularly one that does not control the existing transmission in a given market, clearly by its entry on day one increases competitive alternatives. Its entry is pro-competitive, and, as I think Mr. Neal has already said on that day, a new entrant cannot have market power. Hell, we're looking for a market. How can we have power at the point at which we're begging customers to come sign up for us for our paltry one, two, three, five years, which is about as far as the market will go at this point.

On day one, there is no such thing as market power for a new independent market entrant in the storage business. Over time, could market power be developed? Maybe. I'm not clear that it could happen because, as has been pointed out, storage is an option. In the situations that we're describing, new independent market entrants not connected to an interstate pipeline, not controlling interstate pipeline capacity is an option, not a requirement. Let's assume for a moment that the Commission, as it must, has to watch for the possibility of the development of market power that could reduce the confidence that the Commission must have that the market will constrain rates. The Commission can take a number of routes toward assuring that the market-based rates continue to be constrained by the market to just and reasonable levels. As the 9th Circuit said in the California vs. FERC decision just recently, a periodic reporting requirement is an essential adjunct to the approval of market-based rates. This is true in the Federal Power Act, equally so in the Natural Gas Act. I take that as good news. The Commission needs to be vigilant. If it is vigilant, though, as the Courts have held, the Commission is within its rights to allow a market to operate. Perhaps the Commission ought to require periodic reports as to level of contractual commitment at a gas storage facility. Up until the point at which it's fully contracted, I defy anyone, on a commonsense basis, to demonstrate that the facility has market power. There's still uncontracted capacity in the facility. That means that the market, not the storage provider, is going to determine what the prices for the services are going to be. Perhaps the Commission would look at the duration of contracts when a facility is fully contracted to ensure that the facility has not obtained the ability to dictate prices or terms. Perhaps the Commission ought to give credit to its own programs. The capacity-reduced program allow storage capacity to be sold in the secondary market. Reduced capacity can be a viable alternative to primary, if you will, capacity available in a storage facility. And the Commission, of course, always has the power under Section 5 of the Natural Gas Act to entertain complaints where a market participant detects the possibility that a facility has market power. This has been established as far back as the Elizabethtown vs. FERC decision on market-based or pipeline merchant purchases on the electric side in Louisiana Energy and Power vs. FERC decision. The complaint mechanism is a legally sufficient way to ensure that rates are held to just and reasonable levels by market forces. FERC needs to act now for the same reason it needed to act two years ago to sweep away some of the regulatory underbrush that was impeding the development of new LNG terminals. The decision in the Hackberry proceeding made it a whole lot easier for LNG terminal developers which the Commission may not regret given that there are now, what, 40 proposals before it to move forward with the project. Merchant storage facilities look in a lot of ways like an LNG terminal. Perhaps they look more like an LNG terminal than they look like a long-line pipeline. For reasons that are outlined in the comments we filed, perhaps it's appropriate to look at merchant storage facilities in the same way as the Commission has looked at LNG facilities: look at them as new market entrants, providing additional options to customers. No customers are obligated to sign up for service with these facilities. So, the Commission should, as it decided in the Hackberry decision, take steps to ensure that its policy is not impeding investment.

My second point, very briefly, is that if for some reason, the Commission doesn't agree with me, and I can't think of a reason right now why it should not--

(Laughter.)

MR. BOWE: And cannot approve market-based rates for that occasional poor storage facility that cannot show the market will constrain its rates to just and reasonable levels, I again can't imagine what that would be. But if the Commission cannot see its way clear to approving market-based rates, it needs to make clear that its negotiated rate policy does not preclude the use of commodity pricing in gas storage negotiated rates. That is to say, the Commission must step back from the implication that was left in its modification of the negotiated rates policy that it's just plain no good to reference commodity prices in the pricing of gas storage facilities. After all, storage exists really primarily for the purpose of delayed delivery of the commodity. The price of the gas going in and the price of the gas coming out are the fundamental determinants of how valuable the storage is. The Commission's policy needs to be clarified so that no one comes away with the impression that it is not permissible for a storage provider providing negotiated rate services to base the pricing of those services on the pricing of gas at various points, at different times.

My final point is the Commission needs to act. Coming out of this proceeding, we need a policy statement yesterday, but certainly by the end of the year or so, so that projects like the Red Lake project can have some certainty as to what is going to happen going down the line.

So I fervently hope that the comment that the Chairman and Commissioner Kelliher made at the outset are, indeed, indicative of the Commission's interest in moving forward. In light of the uncertainties in the market, and certainly the Red Gas Storage project desperately needs.

MR. MOSLEY: Will you file for Red Sox Lake Storage?

(Laughter.)

MR. BOWE: Mr. Chairman, I was tempted to make that pun, but I resisted. Thank you for doing it for me. The answer to that question, of course, as I said before, it depends upon you.

MR. MOSLEY: Thank you, Jim. Next up is Mark Cook from SGR Holdings.

MR. COOK: Thank you. My name is Mark Cook. I work with SGR Holdings, developing a permit for Southern Pines Energy Center in Green County, Mississippi, that will be a new storage entrant into the marketplace. I'd like to take the opportunity to thank the FERC for allowing us to come speak here today, and comment on the storage policy review, and I'd also tell you that we recognize and appreciate the effort put into the report that was produced and the work that pulled these people together and had this meeting.

SGR believes that the current permitting process that's involved in and that you asked for comment on works well, and doesn't present any unreasonable impediments to gas storage development. SGR also believes that market-based rates treatment should be the standard for all truly independent storage development, whether there are many, few, or none in a particular area. A lot of the points that support that have been made already. By allowing market-based rates to develop, you'll allow them access to a greater pool of debt and equity providers that will be allowed to earn the rate of return reflective of the true value of that storage facility, be it high or be it low, and it will encourage development where it's most needed in the country and most highly valued.

We also believe that some of the things may slow the development of storage in light of the total agreement and must industry for more storage that some markets or would-be storage customers are still receiving fairly locurious (sp?) balancing overruns, flexibility, waivers of penalties, receiving things from the pipelines on which they hold equity. The pipelines are still being very friendly for the most part today to their storage customers that paid them monthly for the demand charges. I think a lot of those services are beginning to dry up with the electric generation. The need for the short-term balancing that's occurring at points on the pipeline, but so far pipelines have been very helpful to the customers that paid their costs to operate. And the true cost of providing these services to the customers is not clearly defined or identified or known or possibly even recovered. These type of entitlements tend to muddy the water in determining who should step up and provide storage contracts to further support storage development that will increase reliability and reduce volatility.

I think the utilities know these things, and they're reluctant to approach the PUC's request of new demand charges for storage if they can still work with the OBA's, work with pipelines, and the system that's currently in place has worked well, especially where there's not been storage before. They buy gas during peak times and pay whatever it needs to make sure that the burner tips stay on. When they've bought gas that's in excess of the demand they have, and they're able to dump it into the marketplace, somebody will take it a price. The status quo, as it exists today, has been an impediment to further storage development because that's the way have been. People are comfortable working within an environment that has been a servant for storage at its costs associated with it. I think that has also become an impediment to further development for people to step up and take contracts that support development of storage that would actually take the place more responsibly by itself.

SGR believes that existing rate designs and rate levels based on outdated determinants are masking the true cost of maintaining reliability and flexibility. Shippers are reluctant to commit to storage service agreements that include incremental costs that they do not see explicitly in their current rates or may put them at risk for a full recovery within their states. SGR believes the most significant issue impeding storage development today on some pipelines is their rate design that discourages commitment to storage. Some examples are zone batteries that put storage facilities interconnecting a certain point at a competitive disadvantage with the pipelines on services rates for back whole segmented capacity, postage stamp rates, double dips on pools, and segments within the pipelines.

The rates for these service are either not available or excessive related to the costs actually associated with the provision of service. SGR has looked at places where pipelines have benefitted greatly from the interconnecting storage facility and injection withdrawals that can be made at those points and compressor fuel savings on the pipelines are to reduce the cost of maintenance of operating those pipelines and those compressors. But the rates that have been quoted for those areas are normally the max rate for those zones. Also, storage can better serve the whole pipeline system more so than just the pipelines it's connected to. If pipelines can move gas on a short-haul basis and not through zone rates, for pipelines to interconnect with one another, you'd have to pay to get it there. You pay the full zone rate to go into storage. Sometimes you'll pay to come back out again to go to the market area in ways of creating or looking at the tariffs and pipelines work with the storage marketplace and the storage operators and the customers for those that could be creative in finding ways to making the storage more readily available to more of the marketplace and make it more market sensitive to the costs associated with doing that. Some zones are 500 or 600 miles long, and you may only move 30 or 40 miles within that zone to go from a pipeline to a storage facility and back. We think the rates should reflect the actual usage of those instead of paying the full zone rate. Gas supplies tightening and LNG imports growing, the FERC needs to promote flexible design for pipelines that would encourage them to offer short-haul pipelines. Such short-haul service is needed to reduce the price or making deliveries of regasified LNG to and from storage facilities to levels more reflective of the relatively minor costs associated with the service involved. A more flexible approach to sustain short-haul transmission rates, including short-haul back haul rates, would encourage the use of underutilized short-haul pipeline capacity and could discourage the duplication of facilities currently governing short-haul rates to encourage them admits to storage. Modifying these rate designs would promote efficiency in the pipeline grid to enhance competition in the marketplace. When I talked to Mr. Foley about coming to this meeting, he asked me to keep my comments to those items where the FERC really has jurisdiction, where the FERC really works, and, in closing, the two points where I think the FERC can be most beneficial the quickest is at approving market-based rates as a standard for truly independent natural gas storage facilities and new entrants and to -- that the FERC do further study and act within the pipeline tariff and the pipeline markets to encourage the pipeline industry and the tariffs to support further storage development in the marketplace.

Thank you.

MR. MOSLEY: Thank you, Mark. Next up is Don Zinko from El Paso.

MR. ZINKO: Thank you. I'd like to echo the other panelists in thanking the Commission for setting up this conference and allowing El Paso the opportunity to express its views on this important topic.

My discussion, you all should have a handout and

I'm going to follow it fairly specifically, but my discussion is more specific to some siting issues that we ran into on a particular project in Arizona. The project's name, and most of you have probably heard it, is Copper Eagle. I'd like to just discuss briefly what impediments we encountered in trying to develop this project and what the Commission might do to help us get these important projects developed. There's a map that shows storage of the United States, the various storage projects. In fact, this is a FERC map that was put out, but as you can see, especially in the more concentrated areas, there's more storage, most of the storage fields in the country are depleted oil and gas fields. There are some aquifer storage, and it's about seven percent I think, and there's probably seven or eight percent that are salt caverns. If you notice in Arizona, there's no storage at all in the state. One of the primary reasons is there's not much gas fields that can used as storage. There's some oil and gas production in the northern part of the state, but if you look at the Phoenix area, the high growth area that we're dealing with, there's just no depleted oil field or gas field to deal with.

If you flip to the next map, this is a map showing around the Phoenix area in Arizona the various salt domes which would be the primary geological structure for natural gas storage in that state. Of all of the known salt areas shown on the map, I'd like to walk through why we picked Copper Eagle through the process of elimination. If you take away, the cross-hatched salts that we don't know much about and really we want to use. There's two types of salts: domal and bedded. The domal salts are much thicker, much higher strength for storage development. When you take away the bedded salts, you end up with two. One is the Red Lake Storage and the Lupe (sp?) Salt, which is right outside of Phoenix, to the west there, which is Copper Eagle, labeled on the map. What we need, though, is market area storage. What happens on a passive system? There's considerable power generation that's been added to the system over the last five years. We have considerable LDC load that swings. The power generators have a significant demand swing on the system. And although we have four to five pipelines depending on the area that run by the Phoenix area, it's line pack that basically meets these swings. And it's difficult to put gas on the system 600 miles away and get it there.

What we're looking at is storage that's very close to the market area, so when the line pack starts to be drawing down, we can instantaneously or very quickly replace that line pack. Likewise, when the load goes off and the line pack starts to build, we have a place for that gas to go that's not very far away. That's why we picked Copper

Eagle. The problem with it, it's right in the middle of the metropolitan Phoenix area or very close to it. We purchased this. It was under development. We have 455 acres of land on top of this. The next page I think gives you a better idea of why we put this particular salt dome. It's 10,000 feet thick. How we would develop the cavern is shown on there, but as the note says, if this were drawn to scale, you couldn't see this. We would be 3,500 feet below the surface. We're looking at three caverns that would be about 1,500 feet tall and about 200 feet in diameter.

Going on to just kind of some of the safety features that we're trying to develop in this. We're looking at 24 hours a day monitoring. The normal things that we would do under VO2 regulations, but we really went to some other areas because of the metropolitan area and the density around -- the populated density. We're looking at heavier wall pipe. We're looking at putting concrete. We're talking to Luke (sp?) Air Force Base about covering the pipe with concrete, installation of down hole safety valves, burying the pipe deeper. I'll show you diagrams later on. Putting the well heads in bunkers. But we're willing to work with the public in any way we could to make this safe.

The problems we ran into was misinformation coming out of the public which we couldn't counter. The press would not pick up our side of it. Just to give you an example of some of the misconceptions that were out there, somebody said they did a gas dispersion model, and made the comment that if we had a leak in this storage field, in the pipeline, the dispersion of the gas would cover 2.8 miles. We did our own modeling just to give you the idea of the magnitude of this exaggeration that after three seconds, the gas is 300 feet high and it would cover the area of the shadow if you want to call it that. The gas plume would only be I think 2,500 feet, not miles. It's in feet. The other question that came up in the press was that if there was a temperature inversion, and a temperature inversion could hold the natural gas down at ground level. Our modeling showed that the temperature inversion would have to be 350 degrees Fahrenheit. The difference in the temperature, and we tried to explain these. We tried to deal with effects. We would make the storage field as safe as it could be made, and you can't guarantee that there will never be an incident. We can't guarantee we won't get hit with a meteor either.

We need market area storage. The problem before the Commission is we would like to see the Commission help us in developing a policy in educating the public like we've done with LNG. Chairman Wood, if I could read a quote from you, at least the way you were quoted in the trade journals sometime back in May--

(Laughter.)

I think it was regarding LNG, and it says, the Commission is examining safety and environmental issues on how to deal with the anxiety about such projects, referencing LNG, because they're critical. We think market area storage, particularly in the Phoenix area is critical. If the Commission was out helping us, looking at the projects, you obviously have to approve any project we build, but just educating the public, you have much more credibility in that area than we as an energy company could have. That's I guess what I would like to ask the Commission to help us with. There are some addendums I'll leave with you. I'm not going to belabor them, but it shows our wellhead design. We have restraints submitted to the surface. There's one that shows how we would propose to build the wellheads in bunkers. Part of this came about because of the field's proximity to Luke Air Force Base, which is an Air Force training base, and the concern about if a fighter crashed. So, these were some of the things we're trying to work with the public and to make us feel safe. We couldn't get past a bad public press. That kind of ends my discussion. But we could really use your help in educating the public.

MR. MOSLEY: Thank you, Don. Finally, we have

Carl Levander.

MR. LEVANDER: Thank you. My name is Carl Levander with Columbia Gas Transmission Corporation. Columbia is one of the pipeline subsidiaries of NiSource Corporation. I'm here perhaps in a slightly different perspective than the other members of the members that are here.

Columbia obviously operates a large pipeline and storage operation and serves predominantly LDC load. It has perhaps a different perspective on the market than the new entities you've been hearing from this morning.

Just a couple of quick statistics: Columbia operates 39 storage fields in West Virginia, New York, Pennsylvania, and Ohio containing about 246 BCF of working gas. That translates into about four and one-half BCF a day at peak day deliveries. What that does for us is really comprises about two-thirds of the peak day deliveries that Columbia makes to its market in the mid-Atlantic region. By and large, this sort of service is contracted by our LDC customers. What this does it essentially comprises the backbone of our service. The ability to deliver storage on demand is what makes no-notice work in the Columbia system. That's a fairly traditional cost-based service, offered to what you might call traditional sensitive types of markets. With that perspective, I do want to also bring forward the point that our perspective on storage markets is predominantly looking at depleted rates for storage. You heard a lot about salt. That certainly is an active area of the market. But just to keep in mind, 86 percent of the storage in this country today is reflected in depleted reservoirs. That, in many cases, as ours, is contracted under a long-term or perhaps not as long-term as they used to be contracts with LDCs. And thank God, 73 percent of the capacity under contract to the pipelines is held by LDCs.

So, the perspective we bring to the market is serving the needs of heat sensitive loads by customers who are by and large regulated at the state level, and using us to provide their peak day delivery requirements for the market.

We echo what has been brought forward in many of the recent studies, including the staff paper, that there does need to be a significant amount of storage capacity added in this country. Certainly, quite a bit of it in the area in which we operate. One of the things we need to keep in mind is that storage doesn't equate to market delivery. Obviously, storage is a key component of serving markets, but you've got to look at where the market needs are. And there's all -- so the associated pipeline to get there, so a peak-day addition for us is really a combination of storage as well as building pipelines in the more traditional sense.

Getting to a couple of the areas of need for expanding storage. The staff paper accurately pointed out that the easiest way to expand storage is to optimize the existing assets and obviously if there's a reservoir that's there with the technologies that are -- drilling techniques and perhaps fairly minor changes in operations, it is possible to increase the deliverability of existing storage assets to serve market growth; and that certainly is the best place to start in terms of providing an economical product to the customers. We have done that in Columbia. In the late '90s, we had a market expansion project which added about $400,000 a day in deliverability and added 23 BCF of working gas capacity without developing new storage fields. Effectively, it was looking at a way of enhancing the ability to use the storage assets that are out there. I would note at least from our perspective that while we still look at ways to create additional services and out of storage assets that we have, our experience is, and perhaps those of others who have historic storage, is a lot of that has been done at least at a major level. So, to get the significant levels of expansion projected to be needed, we're going to need to be building new storage assets. That's really the place we are right now.

In that regard, Columbia is in the process of developing a storage project in the eastern panhandle of West Virginia referred to as the Hardy Storage Project. That would accomplish about 176,000 a day of additional deliveries into this market and add about 12 BCF of storage capacity. We're working through the FERC's process on that. We're taking advantage of the NEPA pre-filing process, and I'd like to echo points that have already been made by others that we do think that the permitting side of things from FERC's perspective is working well. We think that is enabling us to help bring this to market when we need it.

The other side of the equation, though, is looking at providing the commercial support for projects. And I think we have been fortunate in Hardy to be able to find customers willing to step up for a relatively long-term commitment. But I think the point that needs to be brought forward is in talking about the types of services that we're looking at. This isn't obviously something that limited to storage. There needs to be commitments, contractual commitments, that are made for sufficiently long-term in order to underpin the capital that's being employed to bring the project to market. And that needs to be with credibility customers obviously it's going to be there fore -- need to be there for the long run. That historically has been the LDCs from our standpoint, and a point that always bears mentioning is something that was brought up in the NPC report: the fact that our customers need a regulatory environment in which they can enter into those sorts of commitments because that's what's going to be needed to actually bring more assets to the market at least for the products we are offering.

I would like to take the opportunity to comment on some of the proposals in the staff report. We thought there was some very useful items in there, and looking at the world through the cost of a service lens. I would like to speak to a couple of the rate-related issues that were in the staff's report.

The first item is rate of return. There were I think some helpful comments or questions of whether providing some enhancements in the ROE on regulated storage projects would provide financial incentives to develop additional storage. Obviously, the answer, from my perspective, is yes. You had to ask the question.

(Laughter.)

MR. LEVANDER: I do think in developing storage, there is an inherent risk in storage development that is not there in a pipeline. You put a 30-inch pipe in the ground. You put a certain pressure on it. You know what you're going to get out the other side of it. In developing reservoir storage, particularly, you don't really know what's down there until you get there. At best, you may have some well records that give you a sense of what is within a few feet of whatever wells were out there in the original production phase of a project. Once you get beyond that, it is a little bit of an article of faith. Certainly, the development of additional seismic technology has taken some of the guesswork out of it, but there is an additional risk in terms of determining what truly the porosity, permeability, water content, the thickness of the formations, and all those sort of things are that I think do inject an element of risk in storage development that may not be in other types of projects.

One other issue related to the rate of return I did want to bring up at least briefly: it isn't a storage specific issue, but it does go to the ability to develop large capital projects. A lot of us in the industry are looking with interest at the issue of the applicability of income tax allowances in rates. Where there are projects being developed by either MLPs or LLCs, obviously the Court of Appeals has sent that issue back to FERC. I can't speak to that case. I don't know anything about it, but as somebody who's trying to put a project together, I know that is something that has certainly caught our eye. The only point I would make is that taken at face value, the Court's opinion would seem to suggest that in order to develop a project as a joint entity, one would need to incorporate that in order to ensure that there is an ability to get income tax allowance on rates which introduces an additional level of taxation when the earnings are given up to the ultimate parent. That, in our view, is essentially the same as saying that the actual rate of return earned on that project is being eroded because the two bites at the taxes are going to reduce the earnings below what had otherwise had been anticipated. And that just factors into the whole issue of capital allocation, and what level of return is being earned for the risk. That is something I'm sure that is being looked at in other contexts, but I wanted to note that as an item of specific concern.

A couple of other specific issues that do or one issue that does get go storage development. Looking at the issue of base gas, as the report accurately notes, particularly in a world of high gas prices, the cost of base gas becomes a very significant piece of the cost structure of a new storage entity. One of the issues that we wrestle with as well as others who are developing old depleted storage formations is pointing at the way to get the appropriate level of recognition in rates for native gas which may be left in the ground, but which may not be capitalized as such in the company's books. I just wanted to note that as an issue. There is I think an efficiency to be gained by being able to utilize existing reserves in place as opposed to providing a sentence to effectively pull that gas out of the ground because it's worth more as production gas than it is as base gas.

Just a couple of other points on the rate side. We did look with interest at the question of elimination of modification of the rate review. Obviously, if we go into developing a project and projecting the returns over time, discounting the earnings stream for what future rate activity is out there, it becomes a significant concern. That's a fact of life, and that, then, becomes a significant concern for those who are allocating capital. Anything that gives the developer the opportunity to rely upon the initial rate at a project obviously does provide greater certainty. We would encourage the Commission, if not limiting it entirely, perhaps looking at extending that time in which the initial rates can be counted upon. And maybe as a step back from that, if that were not done, I think something that would be helpful is to the extent there's an adjustment to rates of return in projects that suffered at the front end of it that some recognition that that rate of return would remain in effect for some period of time would have the same effect of providing some level of certainty.

As it stands now, once you come into the next rate case, it's kind of whatever the BCF analyses throw down, and you're back into having to make risk arguments all over again. Again, anything that gives the opportunity to look at and count on the financial incentives that were provided in the certificate I think would be viewed as a positive from the developer's point of view.

On negotiated rates, I do want to agree with one thing that Jim said: it's not the first time, and it may not be the last. I thought Jim's comment on the negotiated rates angle was something that also had occurred to us. While we are looking at things based on the current environment as being in a cost of service role, I think the opportunity that having negotiated rates based upon commodity indices is something that could be beneficial, as I appreciate the Commission's current policy. That would be suspect, if not prohibited. I think if you look at storage and look at what an indexed-based rate would look like in a storage environment, that is very difficult than it what it looks like in a basis differential for a transportation transaction. And while they may not agree with the holding on the transportation side, I think that storage is a separate question that could be addressed separately.

I won't go into a lot of detail here. We can put these in our post-conference comments, but on the blanket certificate side, there are a couple of modifications that I think would be useful from the perspective of someone who is developing storage currently regulated by the Commission, particularly looking at the requirements under the blanket certificate for when replacement wells can be drilled. There are provisions under the blanket certificate that provides some authority to do that. I think there are questions of how far that goes. We would like to propose a modification to the blanket certificate that would give a little more flexibility in drilling those replacement wells. There may be some other things we could look at in terms of how test wells are drilled and under what regulatory authority that would be provided. We do appreciate the opportunity to be here today and look forward to any questions you all might have. Thank you.

MR. MOSLEY: Thank you, Carl. Before we open this up to the Chairman and Commissioners and the panelists, I would like to give the panelists an opportunity to either make questions or comments based on your presentations. One of the things we were trying to get here is a diversity of presentations, and I guess I'd like to thank Don Zinko for not letting the words market-based rates come out of this mouth.

(Laughter.)

MR. MOSLEY: We seem to have general agreement on that. We should be looking for market-based rates for storage. So, with that said, would someone like to get started?

MR. BOWE: I wouldn't want you to think the consensus on that point is anything other than an indication of the truth of the proposition that people have been asserting here. Market-based really are critically important. I'm sure Mr. Zinko would agree. If you had the opportunity, you would prefer to have market-based rates for the Copper Eagle Project.

MR. MOSLEY: Anyone else? Chairman, Commissioners?

MR. KELLY: I'm interested in your thoughts. Start with the assumption that you have market-based rates for storage. What constrains your pricing? What -- How would you price? What do you take into account when you price at some point? It's an optional service, as you said, and so if you're looking at a customer who hasn't had this service, you're going to provide it for them, and they have other options. So, how would you price your service? What alternatives do they have?

MR. MORROW: I think it's important to note that we can't make the mistake that actual gas storage is a price taker and not a price maker. The thing that defines the price that we can do as a hub service, like parking only or firm storage in NYMEX, the New York Mercantile Exchange pretty much sets what our prices are, based upon the prices in the summer and the prices in the winter.

MR. KELLY: Who's currently capturing that spread? The purchaser of gas or is it not being captured?

MR. MORROW: There's two ways to try to capture the spread. You could do it financially and just go out, and customers do do that. They go out and just buy summer gas, sell winter gas, and are able to look at that spread. The customers with more physical needs want to do the same thing, and typically go to a storage facility to do that. So, they end up contracting with the storage facility, looking at those same pricing mechanisms and trying to hedge out the value of the storage to help cover the costs that they're paying to the storage operator.

MR. KELLY: Would you anticipate that new customers for storage would use that as a replacement for what they're doing otherwise in the financial markets, or is it going to be a new service for them?

MR. MORROW: I'd like to say yes and no. It depends on the customer. We have LDCs who have certain needs, and they're typically wanting physical delivery when the time comes. You have trading companies out there that, yes, they look at both. They can either go out and financially hedge certain prices, and they're really just trying to make money off the difference in those spreads, and then you have storage for that as well. So, they have a completely different need. Most of our customers, other than trading entities, are wanting storage because it does guarantee physical delivery when they need that gas on a peak day or in the wintertime.

MR. KELLY: Who talked about -- I think maybe you did. The shipper takes title rule, and why that was an impediment. Can you or maybe other members on the panel explain to me what the policy was behind that rule, which, of course, was adopted before my time here, and why we shouldn't worry about that?

MR. BOWE: I can speak to the reasons behind the development of the shipper must hold title rule. That was to prohibit so-called capacity brokering through pipeline capacity rights would be traded essentially off market. It was intended, as part of the overall effort, to transform the gas stream, the one in which open access transportation was the dominant way in which business was conducted. So, the shipper must hold title rule essentially said that only those shippers who actually hold title to the gas are entitled to use particular capacity. And it was intended to drive all capacity transactions into the secondary market, into the capacity use program.

The difficulty with that is the storage facility might well have a market that would like delivered gas storage services. The storage facility in most situations will not own the gas that would be delivered as part of that delivered storage service. As Matt was suggesting, under the current rules the storage facility essentially cannot be the shipper even though the market may well want it to provide the service of delivered gas at its city gate without a waiver of the shipper must hold title rule. This is a problem that I can say is one that a number of storage projects have encountered, in particular four clients of mine who have tried to deal with the question of how do you provide what the market wants, given the shipper must hold title rule.

MR. MORROW: To put it shortly, it was originally designed to prevent trading companies from gaming the system. We're not trading companies. We're storage operators. We're trying to offer a service. All we want to do is be able to compete with the larger interstates who have storage and then can make deliveries off their entire pipeline grid as opposed to an independent storage operator who is typically just connecting to one or two pipes. Our customers have to come to us. This would allow us to take on transportation and deliver the service to where they're at.

MR. KELLY: So, if there was an exception made for independent storage providers, from that rule, does it undercut the policy or anyway in which the rule was developed in the first place?

MR. MORROW: In my opinion, it doesn't at all. It was designed to focus on the trading entities, the people who are out there trading gas and not service providers.

MR. KELLY: Would you agree, Jim Bowe?

MR. BOWE: Yes.

COMMISSIONER KELLY: Carl, you talked about a storage project that you're considering developing. I was just wondering what kind of capital we're looking at?

MR. LEVANDER: The project we're looking would be on the order of $100,000,000 expenditure to develop 12 BCF of storage.

COMMISSIONER KELLY: Is there a range -- a generally accepted range of costs to develop storage projects in the United States or do they vary wildly? Is there a typical cost to develop a storage project?

MR. LEVANDER: In that instance, what I'm gauging is the cost of drilling the wells and developing the infrastructure needed to move the gas out. And basically, that gets you to the edge of the field. If additional costs are needed to actually move the gas to market, that would be a separate project. I can't speak to whether that's in line or not. What we're doing is consistent with industry standards. I suspect the drilling costs and all that are going to be fairly standard.

COMMISSIONER KELLY: How about Red Lake or the

Red Sox; right?

(Laughter.)

MR. BOWE: I wish I had a good current estimate, but as has been pointed out, the cost of essentially every input to the process of developing a project have gone up dramatically. I know I have not done an evaluation of the costs.

COMMISSIONER KELLY: Do you remember what they were a couple of years ago?

MR. COOK: It was originally $174,000,000 to build this pipeline south to the southern (sp?) of El Paso, which was going to be $240,000,000 total cost.

MR. O'NEAL: I'd like to echo the staff's report. I think it was a good sort of basis to look at for the different types of storage you had. An estimated for salt. An estimate for reservoir. That was a decent basis to sort of use as a starting point. They can obviously vary in and out of there.

MR. MOSLEY: On page 18 of the staff report, there's a chart which goes to that.

MR. ZINKO: I might just add on Copper Eagle, the question I think depends on the size of the field that you're developing. But we're looking at Copper Eagle, and this is -- we've put $250,000,000. We've put many millions in there already. And, you know, developing storage fields are much more -- we're looking right around for a BCF storage, and the salt cavern is $250,000,000.

COMMISSIONER KELLY: Is there a minimum volume of storage that is economic?

MR. ZINKO: I'm sure there is, but I'm just thinking Colorado Interstate's System, for instance, probably the minimum we have is a hundred million a day of deliverability. That was developed some time ago. On that system, we have higher deliverabilities. Obviously, the higher deliverability, when you're developing the field, the better your economics.

MR. LEVANDER: If I could follow up on that. Obviously, economies of scale become very significant within a project of this type. I do think the project, though, brought out in the staff paper about optimizing existing assets those provide. If it's a relatively smaller scale project, there may be a way of reworking a couple of wells and getting a little additional performance out of existing fields that would provide an economical solution.

COMMISSIONER KELLY: Thanks. I can't remember who talked about the increasing need for storage being linked to more LNG in ports and would you anticipate that the storage associated with that would be at the LNG facility or do you think that there's a ripple out effect.

MR. O'NEAL: I don't think the storage

necessarily needs to be located at the LNG terminal. You don't have to have the LNG or the storage sitting right on top of the LNG or vice versa actually. But I think you need to be within some proximity to allow it to have the efficiencies that you would want. If you get too far away, then you're really not getting there. But within, you know, say, a hundred miles, I don't see why you don't have the efficiencies that it would create. I think there's cost efficiencies associated with using storage as well.

MR. MORROW: I would say there's two ways to look at it, and I think Ryan took one, which is how to make LNG delivery efficient. When we said that in the comments that I made, it was really on the other side. What happens when a shipment is diverted somewhere else and that gas just goes somewhere else. Our country is going to need more storage in the ground throughout the United States to be able to make the deliveries to meet the demands we have. So, there's one to make LNG delivery efficient. There's another making sure we have enough capacity to meet it when ships get diverted or can't come in for one reason or another. And it will happen. Even this summer, we saw quite a few LNG tankers heading off to China.

COMMISSIONER KELLY: I was surprised at the comment that on average customers entered into three-year contracts. Is that correct? I guess I would have thought that it would have been a shorter term than that. Not that it's incorrect.

MR. BOWE: I would say that if you averaged all the panelists here, you might get to three years, because of Carl's long-term agreements pulling the average up. And, of course, I'm on the other end of the spectrum, with zero, which pulls it down.

COMMISSIONER KELLY: But there's hope.

(Laughter.)

MR. BOWE: There is always hope, and after last night we know that hope will be rewarded. The reality is that the marketplace is still generally speaking, with the exception of LDCs not stepping up for long-term capacity commitments. I would say that a lot of us we'd think we've died and gone to heaven if we got a five-year agreement right now for gas storage for one of these new salt cavern facilities, for example.

COMMISSIONER KELLY: Why is that? Volatility of prices?

MR. BOWE: Everybody here will have a view on this. I think one of the major reasons we're not seeing longer term commitments is, as Mark has suggested to some degree, the market is getting away without making those commitments. And obviously, if you can get away without making a long-term commitment that may end up showing up on your balance sheet if you do that. If you can ride on the pipeline for essentially three-year will do that until the day when your power generators go offline, because you've drained the line pack. In Florida, for example, to pick a hypothetical state, or Arizona. The reality is as well is that at this point we don't really know what we want to be as an energy industry. It's well known that the people who used to take positions in these markets are no longer doing so. Some of them are coming out of Chapter 11. Some of them just barely avoided it. There is a new breed of player coming in--hedge funds, commodity traders, financial institutions. I am aware of several of them that are actively looking at making long-term commitments to storage. But they're not quite there yet. We're in sort of an interregnum right now, as we try to find out what we're going to do.

What's going to I'm afraid happen is that we're going to find we've drained a couple of these pipelines' line pack down to dangerously low levels, and have to curtail deliveries to power generators, as nearly happened in New England last year, and then realize we really need to make some long-term commitments in construction.

MR. DANIEL: If I could maybe add to that. It is a very constantly changing situation in terms of this issue of the length of term of commitments. Just a few years ago, I think our average length of term in our storage contracts at all of our facilities was as high as seven years. For the last years, that has come down markedly because most new contracts, as contracts expire, tend to be more like one-year deals. So, the average has certainly come down a lot. I sense that may be starting to change in the other direction. Again, we have certainly over the course of the last few months or even the last year started to see more interest in multi-year contracts again, and I think it is a function of a growing perception in the market that we may be starting to approach the point of being somewhat constrained with our pipeline capacity. It's also I think being reflected a little bit in some much higher summer-winter price differentials. We're at the early stages, but I think it's all beginning to build to greater interest long term.

COMMISSIONER KELLY: Thank you.

MR. ZINKO: I'd like to make a comment. I have to mention market-based rates.

(Laughter.)

MR. ZINKO: We would propose a cost of service based rates for Copper Eagle, but that's because with the problem we're trying to solve with the swings on the pipeline, that has to be integrated with the operation of the pipeline, and I think -- but to get to the question on term of contracts. It's a risk-reward relationship. I don't think you can expect companies to develop new storage fields and put in, in our case, $250,000,000 on a whim. And if you can ask the companies to take that risk, I think you have to have the rewards of market-based rates. If they're going to not take that risk on cost-based rates, the companies will look for long-term contracts. In my view, the term of the contract, the shorter the term of the contract, the more it will push new development of market-based rates.

Would, Mr. Daniel, you mentioned, we've met before actually, and I should probably give you credit here and some of our colleagues about the meeting Mr. Daniel and I had six months ago, which kind of helped give rise to this conference, much in the way that a meeting we had with a number of LNG developers, you know, two did the same thing. So, hope does spring eternal.

Mr. Daniel, you mentioned in passing here, the California independent storage policy on page 11 of your written comments. Tell me more about that. What are the parameters the states have used? What's the name of the facility there?

MR. DANIEL: The Wild Goose Storage Facility, the first independent storage facility developed in California. Yes, it is a good reference point I think because California did recognize a number of years ago back in I guess the mid '90s the need to define a separate category of storage player essentially as an independent storage developer, and developed specific regulations around that. An independent storage developer essentially being somebody who's developing storage on a pipeline that they don't have an interest in, that they're not affiliated with. At the time that we developed Wild Goose, the only parties providing storage service within the State of California were the major gas utilities. Not only did we develop and then do a major expansion of Wild Goose, but now there's another independent storage facility up and running in California. All of that happened within the space of a few years, really spurred by this recognition of the need to regulate independent storage differently from the way traditional pipeline or LDC storage is regulated. I think it is a good model and has been very successful in California in achieving significant storage development.

CHAIRMAN WOOD: All right.

MR. BOWE: Mr. Chairman, I might note that the California policy, which essentially says we can't determine whether and at what point there might be market power, but we have decided that the value of introducing new storage in the market is pro-competitive overall is a fairly straightforward policy. You're taking a similar line, and perhaps giving credit to the CPUC. It might have certain political benefits.

(Laughter.)

MR. BOWE: To point out that they came up with a great idea before you did.

COMMISSIONER WOOD: In what year was that policy adopted?

MR. BOWE: It was earlier than some of the recent unpleasantness, but not a lot. 1996, '97, I'm thinking.

MR. DANIEL: 1993?

MR. BOWE: Was it that early?

COMMISSIONER WOOD: Question, Matt, for you. One of the things you mentioned and followed up on the shipper must have title. You also mentioned what I think was needed for you to do that hub-to-hub. One of the things you said right when you started was we don't own gas. We don't sell gas.

MR. MORROW: Thus, we don't have title of gas.

COMMISSIONER WOOD: Got that. But you do want the ability to get contracts for transportation and storage on non-affiliated pipelines.

MR. MORROW: The thing that basically prevents us from being able to do that right now is the shipper must have title. We have our storage facility, and we move our customers' gas to the end use where it's needed. We'd be moving gas to a pipeline and not having title. Currently, we're precluded from it. Also, if we were to try to go down that route, we'd have to be trained to go through these capacity release rules, which are fairly burdensome. We're not releasing. Our point is we're not releasing the service that we bought. It's been melded with our storage facility into a completely new service. So, we want the flexibility just to be treated like a customer, any customer in the pipeline.

The other idea was the idea of a hub-to-hub service. We really would need waivers for the exact two same things: the shipper must have title and capacity release rules, but the idea there is the storage facility at two locations can take a minimal amount of transportation to move that gas over on a continual basis or even at off-peak times when pipelines aren't being fully utilized. But then when it's really needed, you have gas stored up that you could deliver in a location that it's needed.

COMMISSIONER WOOD: I would love to hear from particularly people that may not agree if the Commission were to decide to do that. I just would like to say that certainly is an interesting concept for me and probably for a number of us around here. We'd like to hear from folks in the comment period that follows this, either today in later panels or we'll have time for written responses, probably 21 days or so.

MR. MOSLEY: November 15th.

COMMISSIONER WOOD: After this conference, it would be very helpful if the people who may not agree with that why they think that granting such flexibility to independent storage would be a bad thing, because I would like to really fully understand.

Mr. Daniel, back to you. One more question. You mentioned in your opening comments some obstacles--actually, let me see if that was you. I'm pretty sure it was you. Some obstacles you were having. No, it wasn't. Which one of you were talking about obstacles with interconnections? Who was that? Interconnections with the incumbent pipeline? You were having trouble with interconnections there?

MR. COOK: Several parts of that just negotiating interconnections rather than storage with incumbent pipelines can be a tedious long-term process. Some of the ones we had worked on in the last year or so: we had one basic interconnect agreement for gas to go through a pipeline that took over a year, just a negotiated agreement at the gas end, and one that was completed in probably 60 days. So, just a different perspective on how to do that; how to force the issue to get done, and then where you connect where zones are chosen within the pipelines we're finding in some of these projects, in some of the projects

I've been involved with that you could be pretty close to a zone or pretty close to a zone change or you just have to cross over it, because that's where the geology is located, where your point would be, and may be more difficult around a city or somewhere else to get further from that zone. So, your customers, when they look at valuing your storage and adopting your rate or return on your storage project and the risk you've taken, the cost of the storage gets prohibitive. I mean the cost of the transportation gets prohibitive. It's difficult to appropriately value the storage in that perspective.

COMMISSIONER KELLIHER: I wanted to caution Mr. Bowe about the analogies he's been throwing. I'm a Yankee fan by birth.

(Laughter.)

MR. BOWE: I had taken that possibility into account, and I thought that it was something that even a Yankee fan could sort of appreciate if only on kind of an abstract basis.

(Laughter.)

COMMISSIONER KELLIHER: I almost wore a black suit today, and if you do rename the project, I might have to recuse myself.

(Laughter.)

COMMISSIONER KELLIHER: I have some suggestions.

You could name it the Bill Buckner Project or the Bucky Dent Project.

(Laughter.)

COMMISSIONER KELLIHER: Those would be good names.

MR. BOWE: Johnny Damon wouldn't.

COMMISSIONER KELLIHER: I had one question directed toward Commission staff about market-based rate approvals in the past. Have they been limited to independent projects? My impression is it isn't.

MR. CARLSON: They are not.

COMMISSIONER KELLIHER: Okay. Now, some of the proposals by the independents that we should be more flexible with respect to market-based rates. Are you proposing that we, in fact, pick a date, a future date, and say all independent projects after that date should be granted market-based rate authorization?

MR. BOWE: It doesn't need to be a future date.

(Laughter.)

COMMISSIONER KELLIHER: But it should be limited to independent storage projects.

MR. BOWE: I don't know that I would necessarily take that position. But because my client is an independent storage project, I'm perfectly comfortable saying that at a minimum, you ought to grant that for an independent storage project. The question you'd have to worry about is whether, by virtue of ownership, not just of a specific storage facility, but also the delivery system that links that facility with multiple markets. You are getting into a different question in terms of market power than you have with a standalone hole in the ground, so to speak. I'm not prepared to say that you couldn't find market-based rates. In fact, the Commission has found market-based rates appropriate. In the case of Gulf South's storage facility -- Bisinet (sp?) Storage Facility and its Magnolia Storage Facility -- those are two I'm aware of off hand. I don't see why the Commission couldn't make the appropriate findings. It's just a whole lot easier to do it when you don't have not only the hole in the ground, but also the super highway that gets to the markets on to the same ownership.

MR. LEVANDER: Can I respond to that? We're not advocating something that's necessary for our business model. If the Commission were to go down that path, I think in a situation where it's a new entrant, there are no captive customers or the capital is being put effectively at risk to the market, and especially if it is separate from the tariff services or the pipeline. I'm not sure there's legitimate distinction to say that it should be only independent operators that would qualify for this policy.

COMMISSIONER KELLIHER: Under current policy, pipelines can get market-based rates. Correct.

MR. LEVANDER: Under the current market power test.

COMMISSIONER KELLIHER: It is available, and I thought the argument of the independents was well, we should be treated a little bit differently because we don't, in effect, control essential facilities, and we have no monopoly power. It's an optional service. It should just be easier I suppose they're saying with respect to the independents. And I had a question, too, about something that Mr. Bowe said about negotiated rates. Storage operators that are not granted market-based rate authorization should be granted a little more flexibility with respect to use of seasonal pricing differentials and negotiated rates. I wanted to see if anyone else on the panel wanted to react to that.

MR. COOK: We certainly agree. Again, the greatest value in the storage for people is the pricing differentials that change. It's just within the last month. Looking at injecting in August, September, and October, we've had spreads from $1.80, $1.90, back down to $0.40, $0.50, and back up again. And those opportunities to capture that value and allow utility customers, gas consumers to take advantage of those things via storage to reduce the overall rates and lock in their own prices and reduce it all clearly for them is inherent in the value that the storage facility can return to the at-risk investor. I think it's critical to the commercial success of at-risk storage facilities.

MR. O'NEAL: We would also agree that the concept of allowing more flexibility in negotiated rates would also be something that would allow the storage operators then to capture some of the additional value, because you're talking about the basis spread. I think we're just echoing. I just want to be sure I'm going on the record supporting that as well.

COMMISSIONER KELLIHER: Is it basis differentials you're trying to capture or seasonal pricing differential?

MR. O'NEAL: Purely temporal differentials. That is the fundamental distinction. I have my own views on the Commission's modifications of negotiated rate policy, but certainly when it comes to the question of seasonal price variations, you're dealing with an entirely different issue than you are with basis spreads, calculated on a given day. The concerns that drove the Commission's modification of negotiated rate policies really are not present in the case of storage facilities, which is dealing not with basis differentials, but temporal spreads.

Carl, you were with me earlier.

MR. LEVANDER: I'm still there. I'm behind you all the way.

COMMISSIONER KELLIHER: Thank you very much.

MR. MOSLEY: Let's move on to staff here at the table. They may have questions.

MR. CARLSON: So far, I've heard that we should grant market-based rates, potentially on the basis that we have players that are independent of the market participants. But also on the basis I guess that storage is a service that's not necessary. Then, on the other hand, I'm hearing we need more storage to meet demand. And Mr. Morrow needs storage to meet physical deliveries. If it's an optional service, and it's not necessary, how is it required on the other hand? And how do I take that into account if I'm trying to measure someone's market power?

MR. COOK: I'll start the process. I think that staff did a good job in the report looking at exactly that issue. They talked about the rates that were there for natural gas storage, looked at the seasonal rates, looked at what there are -- there's lots of places in this country now where there's not a great deal of storage. Red Lake and Copper Eagle have been built, and people are surviving. But the fact is at what price does volatility become unbearable to the extent you would like to find mitigating circumstances, either financial or physical to cover that.

Right now, there are lots of markets that don't have regular access to storage, that just live with volatility. There are those that have access to storage and chose not to take it because they're willing to buy and sell to balance this as to using storage as part of that. So, the fact that storage is available to these people, it doesn't mean they do it. They can still do it. But if they chose at some point, I would rather have the physical reliability, the benefits to buy and sell low. I'll go to the benefits the storage brings to reduce that volatility, and then they could chose that path. But, you know, today there's nobody forcing them to take it. Did that answer your question?

MR. CARLSON: I'm not sure that it does. If there's a demand, if there's pent up demand, the pipeline just can't serve, doesn't storage potentially serve that function or step down and meet a requirement?

MR. CROSS: I haven't heard from the rest of the panel.

MR. ZINKO: I just talk about our particular situation. Storage is needed. We have to do something to solve a physical problem on the pipe the way that a man's work and the physical pipe. We need somehow to solve this problem. The storage field -- went after the storage field we thought would be best suited for this. I don't know. We need market-area storage. I don't know when it's coming, but our pipeline right now. The reason we're meeting these market swings right now is that the pipeline's not running full. It's fully contracted, but the pipes are not running full, so we have enough line pack. We've been able to live through these swings. But as the growth continues, and the economy comes back, maybe it's five years. In the meantime, we develop the storage. In our particular case, in Phoenix, we have to do something. We're evaluating whatever options there are to Copper Eagle. But when you look at it at the end of decade, you know, our opinion is that it's needed, period, to serve the market. Something has to be done.

MR. DANIEL: There's a very important distinction to keep in mind here. When you're thinking of how essential storage is to make the distinction between existing storage capacity and any incremental storage, it's mostly been around the issues having to do with somebody wanting to introduce incremental storage, and whether or not the market can function without it. Obviously, there are entire markets that have been built up on the basis of existing storage where the markets just could not function. Without that storage in place, in that sense, existing storage capacity is a very essential feature of the total gas market as we see it today. But there are alternatives to incremental storage. If we want to build an incremental storage facility in a location. Obviously, the market functions without it in a manner now. The alternatives really have to do with people's alternatives to sell gas at different times of the year, and it comes back to price differentials. With less use storage, you're likely to see somewhat greater summer-winter price differentials, reduced ability to move gas supply from summer to winter, more volatility, et cetera. Those are really kind of the alternatives. I'm not sure in a way you'll ever have enough storage capacity to eliminate summer-winter price differentials. It's just a question of how much do you want to encourage incremental storage to keep those summer-winter differentials from getting further apart or keep volatility from increasing more than it has. But clearly, the system functions without that incremental storage facility now, and the argument that has been made here is that by introducing incremental storage, you are increasing competition. You are increasing competitive alternatives to the marketplace. You are not, by definition, producing--

MR. MORROW: If I could use a recent example, like Red Lake. Arizona is functioning today. Every plant that's there is getting gas. They're up and running. Adding the storage facility is not going to affect that market other than give them additional tools to try to mitigate price. Storage is a tool, and we can say it's required, because people want that tool. They need the tool because they don't like the price volatility. But it's not required, in that we don't have to turn a plant down because you don't have the delivery. The only thing that's going to solve that problem is more pipelines. I mean, that's why it is a little of both.

And the second point is even if it got to a point that it is required, the storage facility itself can't affect the price. I mean, if we look at it from the perspective of how much we sell our service for, a firm storage contract is sold way in advance. During some peak time, our customer maybe already has that service, which they paid for typically in the summertime and negotiated a year out in advance. And they had the optionality to take gas out of the ground or not that day. Our customers maybe they try to manipulate the market because they could hold back. But they have just reasons for trying to do that because they're always scared that the next day the price may be even higher, and they want to save their gas, and they want to make sure they have enough to get through each day.

MR. CARLSON: I heard a couple of things in there that I'm having to follow up on.

One is, Mr. Daniel, are you suggesting that, well, gee, perhaps I thought that you said the opposite early on, which was that if there's excess capacity, which allows people to I guess do the financial deals as opposed to deals that are necessary for delivery to reduce volatility. Maybe I misunderstood, but as it gets tighter, there's potentially more opportunity for exercise of market power, which would lead me back to what Mr. Bowe was talking earlier about possibly granting market-based rates on the basis that facilities weren't fully contracted or once they became fully contracted somehow we're willing to determine some measure of market power. Can you further elaborate how we mitigate market power in those instances?

MR. BOWE: I'd start out by pointing out that storage is needed at the metro level, across the North American market. It's not the same as saying a specific storage provider is needed in the sense that it has market power, as Matt has suggested. At the time of contracting, particularly when you're talking about incremental storage facilities coming into a new market, there's a negotiating that takes place. The storage provider has no ability to force its service down the throat of the customer. At that time, as I've said, on day one, and for many, many days after day one, the facility is, as Matt has said, a price taker. It will negotiate with its customers. The customer will value the storage in part on the basis of the seasonal spreads we discussed, and the trading around value for those who would do trading around activities. Those would be individual would have all sorts of different curves that each customer has bringing to the table. But they're not compelled to take service from a particular provider as time goes on and the facility becomes contracted.

Again, all of us will think we've died and gone to heaven if we get there at any time in the near future, meaning in the next five years. The question will be, as contracts roll off, what happens? Can a contract that was negotiated at a time when the facility was not fully contracted, when the facility could not have market power be removed? Are the terms under which the operator proposes to renew a contract or a company wants to roll it over reasonable? That might be something the Commission could look at. The Commission could look at the question of whether at the point at which a facility has become fully contracted on presumably a relatively long-term basis, there seems to have been any foreclosure on the part of the storage provider that a customer might complain about or is the instance of the complaint authority an adequate backstop? One of the things I'm trying to convince you of is that that is a problem we'd like to have down the road. But unless you allow market entrants, we're not even going to get to the opportunity to test the degree to which over time a facility, as it becomes fully contracted and market demand for its services increases, the facilities might being to resemble something like market power. It certainly doesn't have market power on day one, and for many, many days after day one. So, I'd say monitoring the ability to entertain complaints indicated that there's been some withholding or other anti-competitive activity ought to be sufficient. I can elaborate further, but it gets pretty technical, and I think we probably want to do that in writing.

MR. FLANDERS: I was thinking of a question along those lines. One of the issues I see with market-based rates is the renewal entrant. The new entrant doesn't have market power. The customer has choices, but after you get used to that service. A little distribution company, in particular, might say I really need that. I need to renegotiate this, and all of a sudden the price is completely different than the initial price. Is one solution something along the lines of what Mr. O'Neal suggested? A cost of service based rate for a longer term contract, so that when the renewal opportunity came up, there would be that recourse rate, where the option would be to sign up for a longer term, at which point the customer would have some more protection than they might otherwise get under a complaint procedure.

MR. BOWE: I suppose that's possible, though I have to say I get very nervous when the term cost of service is applied to these completely at-risk new market entrants. At what point do you essentially deprive the developer of the bargain that it thought and had entered into by putting its capital at risk? The thing you can't do if you want new entrants into these markets is truncate the opportunity for these facilities to earn returns, reflective of current market circumstances and just the point at which a facility is finally beginning to make some money. And the reality is that that would almost certainly be what would happen. In the situation like the one you've described, you've got to be very careful not to essentially leave developers with the conclusion that they will have an ample opportunity to underrecover their costs. And as soon as they begin to get the point at which they're able to take advantage of the value that the market sees in their facility, as the demand for that facility rises, they'll be capped at the cost of service level. You will not attract investment if basically what you've basically got is downside, and they cap it -- which able to return, some return for the upside.

In terms of protecting individual customers, one message might be if as an individual customer, you're concerned over time about a facility becoming more and more essential to your operations, perhaps you want to negotiate a longer-term contract on day one when you hold more of the cards. That's a possibility. Do you want to follow up on that?

MR. O'NEAL: I just wanted to raise -- I understand Jim's concern. I have the same one. When I hear things like relatively contract, therefore, we should take a look at all the rates. What's fully contracted? A six-month contract for the whole facility? I mean, I'm in the business of selling the service. And if I have 10 BCF, I'm not really interested in selling seven BCF and having three sitting around in my pocket just waiting for someone to show up. So, I'm liable to go in the market and sell it for whatever I can clear it at. Therefore, it's fully contracted at that point. Does that mean I'm going to have somebody coming looking at my rates and saying, okay, now let's reevaluate where we're at. There's a dynamic in all of this. I don't think either of us have the answer. We're sitting here, but I think there's a balance between the two that we're trying to sort of strike, and that's part of why we're all here talking.

MR. CARLSON: I guess where I'm coming from is, you asking us somewhat to depart from current Commission policy, where the applicants have actually demonstrated that they have no market power into I guess a philosophical leap of faith to you have none because you're a new entrant, therefore.

MR. BOWE: The Commission has done that on the electric side. All new uncommitted generation coming into the market after 1997 is entitled to be sold at market-based rates. The Commission has said LNG terminals aren't going to be rate-regulated. The Commission has done what you're describing, and what we're suggesting is storage facilities. What I'm suggesting is storage facilities are more like new merchant generators or LNG terminals than they are like long pipelines that are essential facilities for the markets they serve.

I recognize the problem we've got. It does a require a departure from Commission policy, but it's not a departure in the context.

MR. MORROW: Perhaps you could give us the codes of conduct that you view as appropriate from the independent storage that we apply to electric generators.

MR. BOWE: I think that's a valid point.

MR. KELLY: John, can I ask a follow-up question. I think I get the point that cost-based rates would not be a mitigation of market power measure that would be acceptable. Is there one that would be?

MR. BOWE: By mitigation, I suspect what you mean is some external mechanism the Commission could insist upon to ensure that over time market power isn't accumulated?

MR. KELLY: Not that it isn't accumulated.

MR. BOWE: But that it isn't exercised.

MR. KELLY: It isn't abused; right.

MR. BOWE: One measure that has received judicial sanction is the complaints process if someone believes they have been the victim of the exercise of market power. We have that recourse, which perhaps has gotten a bad name over the years, but which has become legally sufficient. As far as other mitigation, I have some ideas as to other mechanisms that might come into play at the time of contracting. It may be that some of those measures are already essentially a part of the fabric of Commission regulation. The capacity is offered into the market through an open season process, and it's transparent. It allows all potential customers the opportunity to get some services coupled with the Commission's ability to monitor what's going on and perhaps to require, basically reporting on what happened during the open season process. That's not something the Commission currently gets into a lot of detail on, but could. And I think in a sense knowing that the Commission is going to be watching the process by which contracts are let, renewed, new capacity is being offered in the market is itself a mitigating measure.

MR. KELLY: Is there an external index that would exist that something could be pegged to market price or the swing differential?

MR. BOWE: The difficulty there is each

participant in the market has its own sort of intersection of supply and demand curves. It's very difficult to generalize across the entire market and come up with something reasonable that isn't wrong for some group of people.

MR. MORROW: Not only that, most salt facilities, specifically a lot of the value in the service is the optionality. So, what those customers use to say what is the storage facility worth is a fairly complex option model. Okay. What can I pay for this service, and what will I get out of it. So, depending upon volatility curves and futures and what happened yesterday, it would change.

MR. BOWE: And those option models are extremely proprietary, as in they won't let you see them without killing you.

MR. MORROW: I hadn't heard about that one.

MR. BOWE: It's important to the function--

MR. KELLY: Those people who heard about it aren't here to tell.

(Laughter.)

MR. O'NEAL: It changes by location. Every customers' location will change the value that they see for storage. So, if you're talking about somebody in the Gulf versus somebody in the Northeast, the value that they see for the seasonality basis will change drastically.

MR. PINKSTON: I had a question I guess for the independents. Would market-based rates really make a difference right now? I guess the impression is the economics are very difficult, especially for high-delivery storage. And I guess number two to the extent there's some value there, could you have an affiliate non-operating company, unregulated that could hold the capacity and then capture that value through commodity by sell?

MR. BOWE: On the second point, the answer is yes. In fact, a number of operators do have exactly that structure in place. That is, there are storage operators who have affiliates who hold capacity in their facilities and who operate as marketers of the capacity separate and apart from the operation of the facility itself. There's a number of examples the Commission is familiar with. A number of people in this room have things that are more or less like that.

On the first question, which is eluding me at the moment, will it help. The answer is: if you don't do it, I can guarantee you what the result is for a project like the Red Lake Project. There are people I believe who are willing to put capital at risk. They're not willing to put it at risk if they have no opportunity for return down the line.

MR. PINKSTON: In Red Lake's case, having the unregulated affiliate is not desirable or there's some reasons you can't do that.

MR. BOWE: I can't really speak to the question of what Red Lake would do going forward, because that would be under new and different ownership. But it would be nice to think that the affiliate has the ability to capture all the optionality that exists and be able to bring it back to the parent entity. That is an uncertain proposition, and meanwhile the developer, the hard asset owner, has to put all its money literally in the ground. So, you have a bit if a disconnect between the ability to gain the reward that you would like to gain for your investment as asset owner versus potential optimizer down the line. Putting in two different people doesn't necessarily allow you to do what having market-based rates for the asset owner would allow you to do.

MR. MORROW: I think market-based rates would help just for a couple of reasons. Number one, we've seen over the last 10 years, the value of storage is not the same. It varies widely from what it is today to a fourth of that amount. When we look at a cost-based rate structure, it's going to pick some point in the middle; and during the years, where we're getting less, there's no one there to make that up for us in the years that we're getting more. We're just losing it. All it's doing is effectively lowering the overall rate of return of the project. The other key point is that's not what our customers want. They want the ability to pay for a service that they can actually get at that time, on a yearly basis, especially if you move into the hub services type arena--parking, loaning. Those types of services are very clear. They look at NYMEX. They look at the price of gas today. The price of gas two months from now. You can do a park deal, and they'll pay you some percentage of that fee.

If you try to charge more than that, they'll just say no. The would go into NYMEX or they'll find another storage operator that will allow them to do that. But NYMEX is what's setting the prices, especially in the hub services area.

MR. MOSLEY: Let's have a couple more questions from staff, and then we can move on to the Q&A session.

MR. NICHOLS: As a projects guy, I want to switch the focus of this just a little bit. It's clear from the discussion that there's no consensus about how much the storage capacity in this country. Is there a benefit to the market to customers to come into a common understanding of what we have? By analogy, I kind of look at things like the storage report that comes out on Thursday. Here, it seems like we have a situation where perhaps because of differing methodologies, we may arrive at different numbers.

MR. DANIEL: I certainly think it would be of benefit to the industry as a whole to have a clearer picture on this whole issue of working gas capacity and how adequate it is relative to current demand. It is a very difficult issue to get at. To get a real good definition around the physical capability of the storage facilities, I think is challenging. I think people use different definitions when they come up with their working gas capacity estimates. But some greater commonality and some greater confidence in those numbers I think would help. It still leaves the issue, though, I think that it's much more difficult to get at of the difference between the physical capability of all of those facilities and their practical ability to handle the amount of gas that needs to be shifted from summer demand to winter demand. I just don't want to underestimate how difficult it is to get at that. As result, I really think the only way you're going to get a handle on that is by really closely watching the market, and how it responds as storage facilities as a whole start to get used. I think the market starts to tell you when it looks like you can't get any more gas into storage in September and October. Similarly, the market starts to tell you when some very high prices, when it's physical difficult to get more gas out of storage in February than what is coming out. I think that kind of closely watching the market that way is the best indication of when we're approaching constraints on storage capacity.

MR. BOWE: Knowing more would be better. But there is not a correct answer to the question how much capacity do we have and how much -- because the values are so static, the question of how much gas you can get out of a facility can only be answered under actual operating conditions at the moment. You'd have a better idea of what our theoretical total capacity is. You might be able to get a very clear idea of what is the maximum amount of gas you can get into every facility we have in North America. We have a little bit of a margin for error, but knowing exactly what that translates into in terms of base versus working, which is an arbitrary distinction, and what it translates into in terms of deliverability and injectability is very difficult to nail down precisely. The question of whether you can withdraw on a given day will have maybe more to do with your dehydration capability than it will with the number of reservoir based storage or the amount of gas you've gotten in the salt cavern storage, and that may have a lot to do with ambient temperature, which, as we know, changes from time to time. So, it would be better to know more, but we'll never know the answer completely, accurately.

MR. CARLSON: Mr. Morrow, in your scenario where you're saying you do the hub-to-hub transactions, if I've got the picture, you would be combining market-based storage with cost-based transportation. How would we price the transportation. Would you do a separate analysis for market-based transportation on pipeline?

MR. MORROW: We would view the transportation basically as an asset, a contract, that we could fit into our portfolio. And it's just peaking and part of our overall asset base, we'd price the service on a market-based rate, that the price of gas is at point A and point B, and would charge the customer for that service. They will inject. They will withdraw, and we'll be able to charge whatever the rate differences were at that time.

MR. CARLSON: You're not proposing any separate analysis?

MR. MORROW: The separate analysis is basically the idea of hub service is one the ability to do a deal very quickly. When the customer needs something, they want to do a deal for the next day. A lot of our customers are trading on a daily basis for tomorrow's flow. Try to go out and do a capacity release. Go out on the bulletin boards and do all those things. It just doesn't work effectively on a day-to-day basis. You have to just be able to offer a service, let them know what the price, and they get to chose if they take it or not. So, from our perspective, that's how we would price it and look at it.

MR. BOWE: There's no real need to do a separate analysis. The transportation component of this service is going to probably be a service that's capped at a cost-based rate in either the inter or intrastate markets, with maybe a few exceptions. Perhaps the particular transportation will be priced something below the maximum rate, but that's just the cost for the storage provider of providing the hub-to-hub or bundled delivery service that the market's asking for. It's an input to the determination of what the service is worth. But basically, the storage provider has to try to get that rate back in the price it can charge for the service. It's not suddenly making that cost-based -- market-based piece.

MR. MORROW: Basically, we've combined three facilities. We have one facility where the gas is going into that's taking up the injection capacity on that day. The other facility gas is coming out of, which is the other storage facility that's taking up delivery capacity on that day. Then we have the transport that we're moving typically on a continual basis. The day that service is offered we may not be actually moving any gas on that pipeline. We may have done it the night before in hopes that somebody would want to do a service that day.

MR. BOWE: You may not get the cost of that transport back on that day, depending upon what the price is -- that the market will pay that day.

MR. MORROW: I guess our idea -- what we're saying is when we integrate, we'll be able to go out and be able to contract for either storage or transportation, and integrate those contracts into our asset base, and be able to offer these services.

MR. CARLSON: What -- the transportation you acquire, would that be acquired separately?

MR. BOWE: It's available separately today. It may be that the market wants you to combine -- maybe the market doesn't want to be bothered with it.

MR. CARLSON: If you would sort of flesh that out in your comments. I'd appreciate it.

MR. MOSLEY: No more questions from staff. We'll go to the Q&A session.

(No response.)

MR. MOSLEY: We're going to move to the question and answer session for this panel and for staff. Please limit it to the issues discussed by this panel. Again, a reminder: please don't discuss any pending cases. We have volunteers here to kick off the question and answer session. We have Rex Bigler from UnoCal, followed by William Rice, from Central New York Oil and Gas and the Stage Coach Storage Project. They're going to kick off the Q&A for us, after which members of the audience are invited to come up to one of the two microphones that are there. Just a reminder to state your name and what organization you represent. Rex?

MR. BIGLER: Thank you for the opportunity to speak today. My name is Rex Bigler. I work for UnoCal, also an independent owner-operator and developer of natural gas storage facilities in the United States. The first thing I want to do is commend the panel. Everybody had some very relevant topics that I think very well represented what the opinions are and the issues are related to natural gas storage development and the challenges to independent operators in the U.S.

I had a list of things I wanted to reinforce as far as points, and then I wanted to perhaps some of the questions that, John, you had asked earlier with respect to storage. One of the main things I wanted to emphasize, and I think I've heard a little bit about today from Commissioner Kelliher, is that policy is needed that recognizes that natural gas storage is a different, perhaps higher value capacity basis, and also more higher risk component of natural gas transportation service; that policy needs to recognize who the incremental developers of storage are and have a very good picture of what that representation is by the panelists today. It's mostly independent storage developers, and the big distinction there is costs associated with development or failed development are borne by those developers solely. There is no rate-based to vary costs or to supplement revenues to bounce back from some of those developments. So, failed projects cost real money and have real implications to independent developers.

Second, storage development is a risky business. We've heard that a lot today. It certainly is exceedingly true--a high degree of geotechnical risk, particularly for the type of incremental storage facilities that are needed today. We've heard a little bit of talk about reservoir storage facilities, about some of the aquifer storage facilities that originally provided peaking and heating load service that was needed in the country. It's very difficult for an independent storage developer to go out and develop a large aquifer storage facility today. Just looking at the cost of pad gas alone, which would be 50 to 60 percent of the total capacity of the reservoir, it would be very difficult to do it under today's rate structure, rate recovery structure. So, what the industry needs today is reservoirs that can react to the volatility that's created by the increased amount of electrical generation load that's been added to the system. So, they don't necessarily all need to be salt facilities, but they need to be reservoirs that have good permeability and the ability to react real time with some of the load requirements of those electrical peaking generators. We've heard a lot today about market-based rates. I don't need to I think to say -- that I need to say a whole lot more about that, although I certainly support the concept.

We've heard a lot of discussion today, John, on some of your questions about storage. Ultimately, storage is built to provide efficiency to the transportation systems. Part of the way Unoco goes about deciding where it wants to develop independent storage facilities is we model the transportation system of the U.S. and see where additional efficiency is required. Hence, we have developments in northeast Colorado to serve the Colorado Front Range, where we feel there's infrastructure constraints, but also that we just to Arizona, where we have an active development going on to try to solve that particular issue.

The value of that incremental capacity and those markets is going to vary between the stakeholders. What's the value of security of supply to an LDC? What's the value of not having gas on a peak day for an electric generator. Those values are what needs to be able to be captured by the independent storage developers that are really serving that particular need. So, we're very supportive of market-based rates for that reason. If cost of service rates continue to be out there, we would certainly ask to review the methodology for determining the returns that are available to developers under cost of service, recognizing that these are not pipeline projects that are fully subscribed. There's a tremendous amount of additional risk that goes with the development of these projects.

One thing I wanted to hit on that Mark Cook had mentioned is the pipeline companies. In some areas where independent storage is attempting to be built, the pipeline companies are not always as receptive as they could be to it. Attaching those incremental storage facilities to their systems, it does provide, because storage provides efficiency, it also impacts the pipelines. Theoretically, a customer that has storage on a pipeline may be able to reduce its MDQ on that particular pipeline, because it's had to subscribe to a tremendous amount of firm capacity to meet a one- or two-day peak load, so we may have an entire 15 percent load factor related to that particular capacity. But establishing some policies that facilitate the interconnection of those facilities, the timely interconnect agreements to get those done, and also the rate making that's established. Pressure put on those systems to get gas to and from those storage facilities is very important. The storage facility can do a lot of things, particularly high deliverability, good reservoirs, salt projects. We can do just about anything you want to do as far as load following goes, but the only limitation being we can only do what the pipeline companies will physically allow us to do, so there's still that interconnection and there's still a cost associated with moving gas back and forth in those pipelines. That's all the comments I had today. Thank you.

MR. MOSLEY: Thank you, Rex. William Rice.

MR. RICE: Good morning. Thank you for the opportunity to make these comments. My name is William Rice with Dewey Ballantine. I am here today representing Central New York Oil and Gas Company. Central New York is the developer of the Stage Coach storage project in south central New York. It's been completed and in operation for a couple of years now.

I'd like to follow up on three issues raised by the panel this morning, all of which we agree with. The first is Central New York believes the Commission's current certificate process works very well. By cooperating with staff and others, we're able to get our certificate order in a reasonable time and to respond to challenges that came up during construction.

The second is the need for market-based rates. We were granted market-based rate authority as part of our certificate order. We now have a couple years of experience. The flexibility has allowed us to craft rates that match the needs of the marketplace. And without market-based rates, Central New York could not have done up to the Stage Coach Storage Project.

My last point is that Central New York would endorse the suggestion of ENSTOR's Matt Morrow that independent storage projects should be allowed, offered delivered storage services, including the flexibility to compete with pipeline services, possibly including a waiver of the shipper must hold title rule, the ability to hold upstream-downstream capacity on pipelines, and perhaps the ability to assign or sublet storage capabilities outside of the traditional capacity release model. Thank you very much.

MR. MOSLEY: Thank you. Do we have any members of the audience who would like to address this panel?

MR. CHANCELLOR: Craig Chancellor with Calpine (sp?). I've got a question for the independent storage operators and developers. I think the staff report, and Carl echoed it as far as the customer profile and perhaps utilization. Carl, you said 75 percent that has historically been LDCs. Do you see as independent developers that same customer profile moving forward in that same ratio or do you see utilization change in the new storage being developed?

MR. COOK: Craig, I'll take a hand at that. The services that a few years ago I was providing were primarily merchants -- almost all the merchants were taking the storage and leveraging it and providing all the peak-day, 10-day delivery. All the different services that the utilities were requiring. Many of them are since are no longer as active any more. I think the market by now, and I don't know what's being sold on honestly at the moment, but I think there's kind of a stand back and wait to see if merchants develop and pick up that role. Are other people going to take the responsibility to the utilities -- do the utilities take their responsibilities themselves and change the way they pass through gas costs and the way they manage their books before. We always hear about the generators being the person that really needs the storage, the independent generators. Most of them are not storage customers, and don't hold firm transportation, a lot of them, because of the fixed costs in their recovery model. I don't know who the storage customers are going to be going forward. I think LNG people probably need the services they can provide to operate the system more efficiently and effectively, and I do think that the utilities that are currently in that marketplace will come back into that marketplace to replace the merchants that were providing those services before.

MR. DANIEL: I think ultimately still, the biggest ultimate market for storage capacity should be the local distribution companies. It's really their very large and growing winter load requirements that put most of the demand on storage. The real issue is will they be directly customers for storage capacity to a greater extent than they have been in the past, or will we go back to the situation we were in a few years ago where we're increasingly starting to rely on merchant companies to essentially manage that for them, to go out and contract for storage, optimize it, and then deliver them the gas they needed. With what has happened with the merchant energy et cetera, I think it has forced local distribution companies to think again about the need to go out and contract for capacity. But I would tend to think as we go forward, if it does turn out that we do become somewhat more constrained in terms of storage capacity, and therefore there is the feeling of a need to have somewhat longer-term commitments to assure that you have access to adequate storage, I would think all of that ought to lead to local distribution companies becoming more interested in long-term contracts for storage. So, I expect that to be a growing market. There's an important issue there for state regulatory agencies, of course, as well, to make sure that there are no regulatory impediments at the state level to local distribution companies entering into long-term contracts, whether it's for storage capacity, pipeline capacity, or just gas supply. Not requiring that they have long-term commitments, but making sure there are no long-term impediments to having that.

MR. BOWE: On that last point, I might note at least one state commission, the Arizona Corporation Commission, has adopted a policy of pre-approving long-term capacity commitments on the part of utilities, both gas and electric in the State of Arizona because of the concern that the Arizona Corporation Commission has with the degree to which the existing infrastructure is adequate to support over the long term deliveries of both gas and electricity in Arizona and nearby markets. So, today, you can before the Arizona Corporation Commission and seek an order pre-approving a commitment, for example, to pipeline capacity or one offer storage capacity, giving the regulated company some assurance that they will be indeed be able to recover the costs essential to those commitments.

MR. LEVANDER: The point made at the beginning about the market was just to make the point that really we talk about storage. Storage is an asset. Three different types of assets. The issue really is what's the product that it's offering, and what is the purpose. You've heard a little bit of the spread of the stuff here. The thing I was talking about is physical reliability to deliver storage. A lot of what you hear from the independents has to do with financial, as well as physical supply kinds of issues. So, when you talk about customer base, I really think it becomes relevant to look at what is the product that's being offered.

MR. MORROW: Real quick, looking at the United States, the Gulf Coast is probably 75 percent trading companies for your customers as opposed to the LDCs. As you move up to the Northeast, it flip flops, and you're kind of 75 percent is actually being used for delivery as opposed to the trading taking in that capacity. You've got to remember, there isn't a whole lot more storage in that area. So, a big portion of what the contract is LDCs, just because of its location.

MR. MOSLEY: Any more questions from the audience before we break? Yes, sir.

MR. MOODY: My name is Bill Moody. I work with Southwest Gas Corporation. We're dead smack in the middle of the Arizona situation. We serve Phoenix, Tucson, Las Vegas, and parts of the desert California, and the discussion of market-based rates gives me pause, and I may need security, because these guys are going to chase me out of here at lunch. But here's the pause it gives me: the essential service that I would purchase or services I would purchase from storage include the ability to park gas or take gas out and perhaps capacity services because in the desert we have a very peak key environment. What I'm faced with as an LDC that ultimately we're the people you're talking about when we pay the bills, and we sign up for long-term capacity, we have to by our charge. The problem we run into in the State of Arizona we've got tightening tariffs on our pipeline, leading us all inexorably towards some sort of storage facility. But if you add up all the usage and requirement for storage, you probably are going to be able to build one. When you build one, if it has market-rate power, and I have to sign up for 10 years, that strikes me that that would be a very difficult situation from which to determine how much I should pay. It's true. We do have a pre-approval process, but it strikes me that there should be a great deal of care in that situation taken when determining. I'll make a joke here. What rate could be extorted? It's not an extortion plot, but the bottom line is precious few of us in line to purchase these services, and there isn't a lot of trading of gas going on and leading into the future when non-rateable end of LNG comes in at the California coast.

One of the only ways that we'll be able to take advantage of that directly would be to be able to take some LNG rateably end use storage to fill in the gaps in our LDC load profile, which is classic. Every LDC in the country has it. Thank you for the opportunity.

MR. MOSLEY: Thank you. Anyone else?

MR. HOLLIGAN: Jeff Holligan with BP. We don't have any equity positions in any storage field. Let's start with that. But I think with regard to market-based rates and market power, you can kind of have an analogy here with electric markets between tradeoffs between generation and transmission and storage is kind of an asset that can be looked at for it reflects congestion in the system. As long as there's a true tradeoff, if storage prices go high, the transmission system can be expanded to basically devalue that storage. So, I think you have a self-mitigating factor there. It's like a price signal. I'm really not concerned with market-based rates for storage as long as the storage operator and the pipeline are, in fact, competing with each other. I would have a problem if the storage operator took pipeline capacity and priced that capacity based on basis differentials because then they would be self-tied, and you wouldn't have that competition there that you need to mitigate the market-based rate storage by having the ability to expand the pipeline capacity to devalue that storage if the rates were too high.

MR. MOSLEY: Thank you. Did you want to respond to that? I saw you squirming over there.

MR. MORROW: If I could. I definitely understand his point, and I think that a pipeline should be allowed to be a customer of the storage facility as well if they need storage to help mitigate the problems, like we've kind of heard from on El Paso. They could become a storage customer. Utilize that flexibility of the facility to help their system operate better and vice versa. The storage facility should be allowed to take transportation so that they can then compete. Both sides can compete with one another as long as both sides have the ability to take that transport or storage at each other's facility.

MR. MOSLEY: Thank you. We're running a little bit behind schedule here.

COMMISSIONER WOOD: One quick thing on the post conference comments. I want to ask for comments on what type of reporting requirements the Commission should impose if it decides to grant market-based rates to independent storage projects. What would be sufficient activities in addition to reporting requirements that would satisfy our need to monitor the market. If you could let us know those types of things, that would be helpful.

MR. MOSLEY: Thank you. We'd like to take a short break here. We are running behind. If I could have especially the panelists back at 12:15 p.m. That will be a 20-minute break, and we'll kick off the second panel. Again, thank you, everyone.

(Recess.)

CONCEPT OF A PROGRAM FOR CREATING MORE UNCOMMITTED RESERVE STORAGE AND PIPELINE CAPACITY

MR. MOSLEY: If we could get our second panelists to step up to the table, please.

(Pause.)

MR. MOSLEY: Let's begin the second panel. I'd like to introduce everybody. I'm going to introduce everyone in the order in which they will be speaking. Starting on my right, and your left, is James Wilson, Principal from LECG, LLC; John Hopper, President and CEO from Falcon Gas Storage; Jay Dickerson, Vice President, Tennessee Gas Pipeline; Tim Oaks, Manager, Federal Regulatory Affairs for UGI; and Craig Chancellor, Director for National Fuels Regulatory, Calpine, Corporation.

Gentlemen, let's limit this to issues that are not currently pending before the Commission in any particular case. With that, Mr. Wilson, will you get started?

MR. WILSON: I thank the Commission for giving me the opportunity to speak. I'm a consultant. I'm not speaking on behalf of any part. So, my comments are my own views, not those of any client or LECG.

The topic of this panel is would it be useful to establish a program to create more uncommitted reserves, storage, and pipeline capacity, and the notice of the conference mentioned constraints during peak periods and also the increased outages anticipated as a result of inspections under the new DOT rules. The motivation to ask this question is clear: more pipeline storage capacity mitigates the likelihood of constraints and resulting price spikes and volatility in the short-term market. More capacity is better. However, the Commission's policy has long been that the when, where, what, and who of pipeline and storage expansion is determined by market participants according to their needs and willingness to bear the risk rather than by regulatory authorities or programs. Expansions occur when there is market support for them. In my opinion, the Commission's policy in this regard has worked well, and natural gas infrastructure has generally expanded in a timely and efficient manner.

While I don't have time to elaborate, I don't think the periods of high prices that have occurred locally in recent years, and in the west end in New England, are a contradiction of this conclusion. The key to the success of the Commission's policy is the willingness of many market participants to commit to pay the fixed costs of existing and new pipeline and storage capacity through subscription to existing new firm capacity. Other participants chose not to bear these costs, and they accept and bear the risks of high basis differentials and price volatility. Should infrastructure constraints arise, when gas demand increases, and the prospects of constraints appear more likely, consumers and their agents increase their contracting or hedging to protect more of their purchases from potential high prices, and this stimulates capacity expansion.

This policy works well, and there are things that can be done to help it work better, such as providing developers more flexibility to match services and rates to market needs and removing barriers to contracting and hedging by loads.

But a program to create uncommitted reserve capacity would be incompatible with and instructive of Commission policy of market-driven expansion except when the program has some effect, and resulting in some uncommitted capacity beyond what the market chose to build. The short-term impact of the program could be to depress basis differentials and price volatility as intended.

Regardless of how the program might be implemented, by depressing basis differentials and volatility in this manner, it would reward and encourage those market participants who declined to support the system financially and didn't contract by providing them with protection they aren't paying for while punishing those market participants who committed to firm capacity and demand charges by diminishing the need for and the value of their firm capacity holdings. The result would be to reduce the incentive to hold firm capacity or commit potential new capacity offered in LDC, exactly the opposite of the incentive the Commission's market-driven policy requires. Such a program could, therefore, cause market-driven capacity expansion to slow or come to a halt.

The California Commission asked very similar questions in a rule making earlier this year. All commenters criticized and opposed the concept of uncommitted reserves of storage and interstate pipeline capacity, with the exception of a few parties who were potential providers of such reserves. In responding to the rule making, the California utilities called upon to propose that specifically how such reserves could work, identified numerous issues and problems regarding how such reserves could be provided, how they would be used, how the storage would be refilled, how it would be paid for, and we were unable to find good answers to many of these questions. That was proceeding RO401025. I worked for one of the respondents on that.

Policy changes to encourage capacity adequacy should be designed to work within and enhance the Commission's fundamental approach of market driven expansion rather than going around and subverting this approach. As suggested by the staff report and other commenters here today, affording storage developers more flexibility in designing services and rates will encourage development of new capacity and contribute to adequacy. Staff's proposal to grant market-based rates to new independent storage, even if the absence of market power cannot be definitively established, with possible mitigation measures, is an approach that should be considered. One approach if mitigation is considered necessary could be a requirement that the storage facility maintain a minimum level of contract coverage, even if some discounting of rates would be required to achieve this. For instance, it could require that they have 70 percent covered for at least one year or two years, and 40 percent for three years. Contracting transfers to control over and the benefits of the capacity to other parties; and, therefore, mitigates the ability incentive of the other to exercise market power in the short-term or long-term markets.

The concern was raised that upon recontracting, market conditions may have changed, and it may look like the facility has market power. I think you can imagine circumstances under which that would occur. That would likely be temporary because the market signal would be there for a new storage or a new pipeline capacity that competes with it to move in. So, I think where there's a concern, I think it would be a temporary situation. The flexibility to design cost-based rates also encourages and facilitates new capacity, and I would just add one thought to what was said this morning: restrictions on storage rate design reflected in the equitable method I question whether they serve any public policy purpose and perhaps could be scrapped. Inefficient locational pricing, such as short haul and back haul tariffs that don't reflect costs, also raise the cost of a new storage facility in providing its services to customers, and addressing these problems can remove the barrier to entry. The staff report suggested that there might be something about the Southwest, such as that storage there cannot pass the Commission's market power test. I don't agree. I think that the fundamental concept in the market power test allows it to be applied in a realistic manner, and I think that, applied realistically, storage in the Southwest could pass it, if, indeed, that test is still needed.

With regard to pipeline capacity and potentially reserve there, the Commission might want to consider policies to provide stronger incentives for pipelines to minimize capacity reductions and their impacts on customers, especially in light of anticipated increase in inspection-related outages. One example of such incentives is included in the regulation of the United Kingdom gas pipeline system operator, Transco. Whenever Transco cannot deliver the firm pipeline capacity that is sold, and its shippers intend to use, it is required to buy back the capacity in the market, and it can do it either in the short-term markets or it can do it in the forward markets. Transco faces an incentive mechanism that gives it the incentive to minimize the cost of those buy backs, and recently it's beating targets for those costs through various innovations that have minimized outage time and minimized the cost impact.

This approach shares a number of efficiency and incentive advantage compared to the tariff rules that provide for pro rata reductions with possible demand charge credits. To summarize, I think the Commission's market-driven for capacity expansion works well, and can be made to work better, such as providing greater flexibility to match services and need. The program to put your thumb on the scale and create uncommitted reserve storage pipeline capacity would backfire, discouraging market-driven capacity development. So, I encourage the Commission to reaffirm its commitment to its market-driven policies, and to reject the notion of a program to create uncommitted reserve capacity as incompatible with these policies. Thank you for the opportunity. I hope my comments were helpful.

MR. MOSLEY: Thank you, Mr. Wilson.

Next, we have Mr. Hopper of Falcon Gas.

MR. HOPPER: Thank you. John Hopper, President and CEO of Falcon Gas Storage Company. I want to thank the Commissioners, the Chairmen, the Commission staff for the opportunity to speak here today.

Rick Daniel in a prior panel offered us a slightly different working definition, if you will, of what working gas storage capacity is, which I happen to agree with. I'd like to offer up a slightly different definition of what an independent storage developer is. In my case, what an independent storage developer is, is a storage developer that's not affiliated with an oil and gas producer, a pipeline company or a local distribution company or an electric utility, and if you look at the members of this panel, I think that narrows it down to me and Mark Cook that would fall under that definition. The reason why that is relevant to me as an independent storage developer is this. It has to do with access to capital markets, and the cost of that capital and how that relates to the development of independent storage projects. My cost of capital is essentially set by the private equity capital markets. That's where our project development capital comes from. So, when I have to access capital, I have to go in front of my board that consists of members of a private equity capital firm and convince them that a project would yield a return on their invested capital that meets their return requirements. In most cases, that's an excess of 20 percent internal rate of return. Some of them will tell you that it's higher than that. That would compare with a different internal rate of return threshold. Of most the companies that spoke today, that would have some relevance in terms of not only of the applicability of market-based rates but also I think circles back to this idea of reserve storage capacity. I was heartened when Chairman Wood invited us to be frank and forthright in how we feel about it.

You have my PowerPoint presentation. There should be no doubt about what our position is on this issue. We are opposed to it in every possible sense of the word, and here's why: let me first say that I understand the rationale for it. It's a noble gesture, as was Prohibition--

(Laughter.)

MR. HOPPER: As was pervasive wellhead to burner tip regulation. The goals are noble. The question is, is that the best way to get there. Obviously, we feel it's not. The reasons for that are several, are many: first of all, I don't see a way to do that without the cost of that storage being subsidized by generally commercial and residential rate payers, which I don't think is what the Commission has in mind or would intend. But here the law of unintended consequences would come into play. I don't see how independent storage developers could participate in that program. It would, by definition, have to be a regulated utility that has a core-rate base customer base to pass those costs through. Then the question is, well, are the people paying the costs receiving the benefits of that storage? And that's just a whole 'nother slippery slope that I don't think is worth going down to begin with. It also sends the wrong pricing signal. The pricing signals I think are pretty self-evident. When you look at page 13 and 14 of my presentation, that's the value of storage. The volatility and the value that can be extracted through the forward NYMEX curve. By putting the gas curves today, hedging it, taking it out six months from now, five years from now or whatever it is, that's the value of that particular type of storage. Multi-cycle storage has additional values that can be captured by using that to mitigate or capture the value of short-term volatility events, which were spoken about eloquently on the prior panel.

Load following is another service we provide as do the facilities that our analysts operate as well. Reliability, that's something that the market is going to put a price on. If it's valuable to the local distribution company, the power generator, a gas utility, an electric utility to have, the reliability of storage as a source of supply. They're going to put a value on that.

Frankly, I think they ought to be able to negotiate that value with the storage provider. For an independent project, I just don't think that certainly pervasive cost-based rate making makes sense for new independent storage projects because it's just not going to attract the capital necessary to develop those projects. And, again in my case, the only way that I can deliver a 20 to 30 percent internal rate of return on invested capital equity is really through leverage. I have to be able to get bank financing, low-cost bank financing to go along with the equity necessary to build a project. And, frankly, that's why, for example, our New York Project hasn't been built yet, even though it's been certificated for almost a year. We can't get the bank financing. The reason we can't get the bank financing is because we cannot get creditworthy customers to step up to the plate and sign 10-, 15-year contracts that will support that kind of financing. And the banks just aren't in the business of loaning long-term 17-year money at LIBOR plus 50 basis points, without sufficient credit capacity standing behind that. We cannot offer that ourselves. Some of the other independent "storage" providers may, through guarantees from their parent companies. We don't have that option available to us. So, we've had to explore other options to try to get these projects built. Joint venture partners. Perhaps selling the projects if we can't get customer support on our own. You know, it's not just that. It's a series of events that have transpired really over the last four or five years since we started this company that are out of our control, and are really out of the control of the Commission.

When Enron goes bankrupt, that affects my access to capital. My cost of capital, the credit requirements that we have to meet for customers, I didn't do that. It wasn't my fault. But I bear the brunt of that or something like what happened at Moss Bluff happens. That affects me, because my insurance rates go up. It affects me because customers who didn't want or think they needed insurance or LDC letters of credit in place to protect their storage inventory. And now, I think they need that. That wasn't something that I did. But I have to pay the cost of that as a storage developer.

So, there are all these extraneous events that take place. That's all by way of saying I'm not complaining about that. That's just -- it's just what it is. The FERC certainly doesn't have any control over that, but to then suggest that one way of mitigating this problem, of price volatility is to, in effect, underwrite the cost of developing internal storage, essentially puts me out of business.

I cannot compete with that because that is, in a sense, subsidized storage. I already compete with that. The markets in which we operate in Texas, and some of the other panelists have talked about, I have to compete with pipeline park and loan services, which are typically not cost-based. There's no cost attributed to them. They're setting, in effect, a ceiling for what I can charge for storage rates. That's not entirely true all of the time, because most of those services are interruptible, but it's our job, as developers, to say to the market: look. Our storage is worth more. Our service is worth more, because it's firm, and you can't count on that pipeline park and loan service to be there all the time. And while they understand that, they have to look at, and I think the prior panelists spoke to this, they have to look at, well, if I can get it 90 percent of the time on an interruptible basis, and the 10 percent of the time that I can't, I'm just going to pay freight. And if gas goes to $40 for three days, so be it. That, right there, that sets a cap on what I can charge for storage. Those two things combined. If you look at that over a given time spectrum, a year, six months, five years, whatever it happens to be, we should be so lucky to be looking at five-year contracts. But that's what a potential storage customer is going to look at.

My job is to go in and convince him that I can deliver a service that meets his needs at less than the aggregate cost of those kinds of services, if you will. That's been the challenge in this market. My point is, I would ask the FERC not to entertain the concept of, in effect, becoming an arbiter of what the market's needs are, where storage should be built, how much it should be built, who should be building it. Let the market decide that. Let the market bear the consequences. If their decision is I'm not going to contract for long-term storage, I'm not going to contract for storage at all, if the price of gas goes to $70 at the New York City gate, the customers pay, because they had the opportunity to contract to meet that kind of volatility. In some cases, that's not all together true. If you can't get pipelines built in New York City a la Millennium, they don't have the option to do that. That's another market-driven issue, where you have landowners in Westchester County or whoever saying, look, not in my backyard. I don't want them built there, and you've got the same problem with LNG. You've got the same problem with storage facilities to some extent.

But that's the market speaking. We need to listen to what the market is telling us. I think that the NYMEX sends the correct pricing signals. You can pull up auction contracts or NYMEX contracts everyday and look at out months and see how the market is valuing that volatility. In a sense, that's what you're selling the storage developer, is a call option on gas or a put option on gas, which all -- and the market is perfectly capable of pricing those services and telling them what it's worth, and where. You can pick up the gas daily and see how the market is pricing gas at a particular point that's listed in that particular publication, and the volatility associated with price units at those points. That will tell you, gee, that's a price where we ought to build storage, or that's a price where we shouldn't be building storage. The bottom line is: let the market work. And the market will send the correct pricing signals to storage developers. Then the question becomes can the storage developer earn a rate of return on invested capital that sufficiently compensates him for the risk of developing storage.

The prior panel enumerated a number of risks associated with developing storage. I've enumerated a number of them in my presentation. So, they all have certain development risks and operational risks out there associated with them that play a role in how storage should be priced and the kind of return that investment capital believes that it need to have in order to justify deploying capital into those assets, and I think the market will work. It may lag behind a little bit in terms of when it finally decides that this is necessary, which I believe it is. And we've been preaching this for five years that this kind of volatility is going to happen, and that, yes, the next generation is going to have a pronounced effect on how gas pipelines are operated in this country. That's all coming to fruition.

I am waiting for my bank account to reflect the fact that we were right. It's a difficult business to be in, and until the market is willing to step up to the plate and pay the price, we're going to be operating under short-term contracts. And when the market is in the kind of configuration it is today, we're surely going to be out there trying to capture that value.

I was interesting in sort of the dichotomy between Matt Morrow's model, which when we started Falcon was the one that we adopted. Look we're a warehouse. We're going to rent space. That's all we do. What Daniel and their model is to combine the commodity along with the storage capacity, frankly, in this market, I'd lean more towards Rick Daniels' model, and away from our original model, because it's very difficult to capture the full value of that without bundling it with a gas commodity. I even heard Matt say, look, we need to bundle storage with pipeline capacity in order to capture the basis differential, as well as the temporal differentials that storage allows you to capture. I would go the other way and say, make the pipelines unbundle that service. That's the way to level the playing field, so that the market knows what the true cost is of park and loan services. What the true cost is of using a line pack to provide storage services. The market doesn't know that because that price is masked because it's being underwritten by firm transportation customers who may or may not have access to that separate component, that park and loan, which is the storage service anyway you look at it. They've already effectively underwritten the cost of that service through the various demand charges on firm transportation, and that is another false market signal the market is getting. It's just not true. That does not reflect the cost of providing that service.

First of all, I thought the staff did a terrific job on this piece that they did on storage. I think it -- they really did a great job of capturing the essence of the storage business as it's constituted today, and I was intrigued by a little graphic they had in there. I think they took in the presentation that C&G made at a storage conference about comparing the cost of developing I think salt cavern and reservoir storage. I'm not a proponent of reservoir storage, but I was intrigued by the fact that you can apparently develop nine BCF of working gas storage capacity with only $3.2 million worth of pad gas. At six bucks, that's half a BCF of pad gas from nine BCF of working gas capacity. I'm here to tell you, that's not possible physically. To support nine BCF of working gas capacity in a reservoir storage facility, I don't care how good it is, you're probably looking at five to six BCF of storage capacity if that slide is accurate.

There are some cost benefits being enjoyed by that project that are coming from somewhere, and I think that's something that if the Commission is interested in promoting independent storage development, they need to look at that, and really take a hard look at what I believe to be price subsidies that are taking place in the non-independent storage market.

With that, I think I've talked too long already. Thank you.

MR. MOSLEY: Thank you, Mr. Hopper. Mr. Dickerson.

MR. DICKERSON: Thank you. I appreciate the time to discuss the state of the industry with you. I guess one thing that hasn't been said I'd like to open up with. If you look at changes in the industry, there are often times necessary and helpful, but there's a backup that I think is important. If you look at the natural gas industry, as I have over my career, I think we're in a period of relative stability which provides a lot of benefits for the industry, and I think it's really a resource just as the energy commodity is. So, I applaud the Commission of getting over the humps of 636, 637, and some of the other implements of changing the industry that have provided some degree of stability for us. I'm with Tennessee Gas Pipeline. Tennessee Gas Pipeline is a long-haul pipeline from the Gulf of Mexico to the Northeast. We originate in south Texas and offshore Louisiana and terminate in New Hampshire. We have a peak day send out of seven or eight BCF a day, depending on whether you measure it this past winter or the winter before. We are the tail of two pipelines so to speak. Our system is dramatically different. As you look at our system from the south, and you look at it from the north, and you move into the eastern half of New York, Pennsylvania, New Jersey, and all of New England, we are, I would argue, a constrained system in that we operate at or near peak day much of the winter. As you look at our system from western New York and western Pennsylvania back to the Gulf of Mexico, we didn't realize this, but we were ahead of our times. We are a reserve margin pipeline, and we have the better part of a BCF of capacity that's unsubscribed on a long-term basis. So, you have two very different worlds we operate in, and I'd like to discuss things from those two very different vantage points, and how that might impact policy issues for the Commission.

In looking or developing a policy position, in my view, it's always good to step back and have a view of the world. I don't claim to have the only view of the world, but I'd like to step back and look at what I think are some facts that tend to say what might make sense from a Commission standpoint and a policy change standpoint.

There are much higher gas prices than we expected, that the higher gas prices are very much locationally defined. If you look at prices in New York, they are several times a multiple of where gas prices are in the Gulf of Mexico. So, I think there's a significant issue that we have very limited liquidity across the United States, upper eastern half of the United States. The good news is I think we have a tremendous base of supply and base of liquidity in the Gulf of Mexico. The MPC study, which we agree with the conclusions, tends to suggest that the Gulf of Mexico is going to be modestly climbing as a supply region. We're optimistic that that will happen. In our view of the world, we think LNG is an important new supply source for the industry, and we think it's probably going to migrate disproportionately toward the Gulf of Mexico for many reasons.

There is obviously the multiplicity of market access, the existing of excess processing capability, and I think today's topic, the geological friendliness of the area to storage development, which I think will go hand in hand with LNG receipts and the building of LNG supply in the portfolio of large suppliers. We have other resources in the Gulf of Mexico, other important issues that I think are out there.

If you look at pipeline contracting practices, I think we've been given more credit perhaps than the first panel for having a stronghold of contractual controls over the marketplace. Pipeline contracts used to be much longer term than they are today. If you look at our average length of term today in the Tennessee Gas Pipeline over the last year or so, it's fluctuating between three and one-half and four and one-half years. I'm not going to ask for market-based rates, but, to me, that is not a dramatically different situation than some of the storage providers that existed in the first panel, and one thing that has changed with the higher gas prices that we're hoping will change contracting practices, as John mentioned, and I wholeheartedly agree, we are in a capital intensive industry. Within a capital intensive industry, financing is important and to set up financing and the term of contract, so, certainly for new capacity expansions, getting adequate commitments for the marketplace to backstop portion of the capital that's being employed to provide new capacity in the marketplace is as necessary. And one thing we're hoping that's going to change is, as we look at the average cost of pulling capacity into the market from the Gulf of Mexico into New York is, for instance, today six percent of the city gate delivered cost, not because our costs have changed dramatically, but because gas prices have climbed so much in the relative scheme of things, holding pipeline capacity is roughly a third of what it was only five years ago. And that is a significant change in the world that we think exists, and it's going to be here over the entire period that we think it's going to be here for a good period of time.

The other issue I think from a policy matter tends to drive actions, and I'll give you my thoughts on what policy options you might want to consider after I go through this, is the dramatic difference in regulatory structure for the gas industry versus the electric generation industry. This hits us most directly in the New England region. If you look at the two markets in the New England region, it's the LDC markets and the -- they represent 122 BCF of contracted capacity in New England. They're all fully contracted. The Commissions review the amount of contracts they hold, and they typically try to build in reserve margins to cover contingencies to be able to serve their markets as they need to serve them. There is not a similar look on the electric side of what's adequate to support the electric generation load in New England. In fact, in our system in particular, we've gone back and placed specific plants attached to our system. There's nearly a 40 percent gap between what is actually contracted and second what the actual total generation capability of those gas-fired generators are. So, there's a reliability issue to the extent that all those plants are needed during the season. There's a substantial reliability gap between those -- what is contracted and what is not.

We're not pointing fingers at individuals in the marketplace. In fact, we think electric generators are somewhat disadvantaged in that they have no ability to secure the adequate, appropriate portfolio of gas supply contracts or transportation contracts that will support their reliability capabilities on a peak day basis and their flow-through capabilities. And there are significant credit challenges to many of those parties in New England. To me, that is an area ripe for policy reconsideration, to try to consider what are the benefits as well costs, but benefits of providing an ability of ultimate generators of gas to be able to flow through the cost of holding enough firm transportation capacity to reliably serve core markets in a peak day situation.

Switching back to the other side of our system, the other half, the reserve margin side of our system, my staff works daily to try to marry up that reserve margin, and we have today with new market growth, and not to transfer it to our competitors. It is a challenge for us. I recommend it to any other party, but what it does do I think in the way of the storage issues that have been discussed today. We are -- part of our field in new storage. If you look at a new storage field, that could potentially be developed in Western Pennsylvania, buying transportation capacity. Those are all tourniquets that the market faces. We have no objection to market-base rates by independent storage operators. I do think there are some corollary pricing issues that go along with that model as it relates to pricing pipeline capacity. Our fee for the Louisiana to Pennsylvania is $0.35 demand charge on the 100 percent load factor basis. It would seem to me to be appropriate without getting into the issue of changing the regulatory scheme in general, it would be appropriate to me to allow pipelines to provide daily sensitive pricing variations in their rate to accommodate market circumstances, so long as on an average basis over the full year. We would not get more than our approved average yield costs. This does two things: it benefits both the pipelines and storage providers. We would no longer have an artificially low price in the wintertime that would undercut what they're trying to sell. At a true market price in the wintertime, that would be a policy consideration or a pricing corollary in the pipeline industry I would suggest you consider along with market-based rates.

I think I've probably used my time, and exhausted my comments at this stage.

MR. MOSLEY: Thank you, Mr. Dickerson. Mr. Oaks.

MR. OAKS: Good afternoon. I'd like to thank the Commission for this opportunity to speak. I'm Tim Oaks from UGI Utilities, Inc., in eastern Pennsylvania. Today, I'm speaking on behalf of the American Gas Association.

I'd like to cover three topics today. The first topic is LDC use of storage. AGA is concerned for some time now that there seems to be some misconception about how LDCs use storage, how we contract for it, how we plan for it, how we use it. In fact, I heard some of those misconceptions already today. Then I will move on to the topic of this panel, the uncommitted reserve capacity, and then finally a brief discussion about some market rates.

AGA members represent 90 percent of the gas that is delivered at retail in this country. As the staff report points out, we hold the majority of storage. We hold that storage for both the merchant and delivery functions that we provide. We utilize storage to meet retail obligations. We assure that we meet our winter requirements through storage. This morning I heard storage is an optional service. For LDC's it's not an optional service. It's a critical component to what we do. It provides a large portion of our deliveries at the time deliveries are most critical. We focus our planning on delivering for a firm, reliable service. This cannot be overemphasized.

While we do use storage for other reasons, like price hedging, daily balancing, and no notice service, those unfortunate consequences of holding storage, our planning focus is still firm, reliable deliveries.

In my slides, I present a graph which is sort of gas supply planning 101. It provides something called a load duration curve, a bit of an unusual curve in that it resorts temperatures from coldest to warmest. It provides a quick profile of how LDCs face temperature sensitivity during the winter season. The planning focus of any LDC is to optimize its capacity portfolio to meet that load duration curve. We want to do two things. We want to maintain reliable service, and we want to meet it at least cost. We want to minimize fixed costs.

The second graph in the handout superimposes capacities on that load duration curve. The lines and step lines you see on that graph are representative of an optimized portfolio. It can be broken into three parts, as you know. FT, which is the flat line, which represents how firm transportation is more a base load serving capacity. Storage, which are the step lines immediately above firm transportation, which serve to sculpt our capacities in a form that meets the demand requirements of the system. And then finally peak shaving, which is the step line at the very top for the very coldest days.

The third graph focuses on storage. Sculpting of storage creates three level of storage that LDCs contract for. I call the first new peak, approximately 20 days or less storage. The next one intermediate storage, which runs from 25 to 75 days, and then finally seasonal storage, which tends to run from 75 days to 150 days, the full winter season.

These differing levels of service are the primary tools for optimizing our contracts and for maintaining least cost. They also are part of close scrutiny by state commissions.

As I pointed out earlier, they are the primary components of our portfolio for the meeting of winter requirements. The next graph focuses on some of the benefits we receive from helping storage. We do use the price hedge of the summer injection versus winter withdrawals. While those benefits have lessened or become less assured over the last few years, those things still exist and we do use that physical hedge. There seems to be confusion regarding how LDCs inject storage versus price plays. Price plays generally are handed by marketers.

Virtually all LDCs are injecting during summer season. Even if the price levels we are experiencing on future NYMEX contracts are decreasing as we go through the winter, we will be injecting storage. We have no choice but to inject. The obligations to serve our firm customers outweigh any price. It's also been pointed out that storage injection capacities are often less than withdrawal capacities. Therefore, to the extent that we have longer storage services in the form of seasonal service, seasonal storage or intermediate storage, it generally takes most of the summer to inject those gases. Again, most price spikes come from the marketers.

Finally, summer injections. The differential in prices between summer injections and winter prices has, at times, become less pronounced because of the lack of competition in the summer months.

Just to summarize the things we focus on: the obligation to serve firm service drives all planning. In early November, all LDCs are close to full inventory. On March 31st, they're all close to empty. We take one full term for most of our services. There are variances in storage injections during the summer we realize, but it is not coming from the LDCs. While we do make some adjustments based on price levels, given the limited flexibility that exists in storage contracts, we will still fill storage.

Also, in addition, most LDC storage is market area.

Generally, reservoirs or aquifers, having only one term per year, generally what we do is we fill throughout the entire summer and withdraw during the winter season. While we do hold some production area storage, those are mainly for commodity reasons, for replacement of supply during well freeze offs for short-term least cost activities.

I'd now like to turn to the question of uncommitted reserves. Certainly, simple supply and demand theory would suggest that additional capacity would reduce volatility. I'd like to point out, however, that capacity constraints are only half of the equation. Indeed, some additional capacity might limit some of the upward volatility on demand pressures, putting pressure on higher prices. However, the other half of the equation, and I would argue maybe more than half of the equation, is the availability of the commodity itself. As long as supply remains tight, volatility will remain.

While AGA finds the idea of uncommitted reserves an interesting idea, we have some concerns. The first is obviously cost allocation. We're moving to the bottom line. Who pays? This raises other questions. What is the appropriate level of service for each pipeline? Is it different for each pipeline? Is it different regionally?

Does the pipeline earn a fair return? I guess I know the pipeline's answer on that one. How is the construction certificated and financed?

The second issue AGA has is the nature of the demand pressure that we're currently seeing. As I have emphasized earlier, LDCs focus on our core responsibility: our obligation to serve. We design and contract where a portfolio can meet our design loads. Therefore, the LDC loads are not a surprise in peak situations. We are not adding to any shortage of capacity. Much of the pressure appears to be coming from interruptible loads. We remain on at near peak situations primarily from electric generation and other industrial loads.

These entities have made the economic decision to shun from capacity. In doing so, they're sending the wrong market signals. They're increasing demand into those situations and are attempting to commoditize the capacity market while LDCs pay the fixed cost on an annual basis. Given this reality, creating what would in essence be additional capacity to exacerbate reliance on inappropriate services during peak conditions, the LDCs will stand firmly against subsidizing excess interruptible capacity that would be created through a mandate to build reserve capacity. If a reserve margin develops through market forces, that is another matter. The market will be signaling a willingness to pay and a subsidization issue would not come into play. For example, some state commissions already require LDCs to contract for reserve capacity. Margins for reliability purposes, but holding reserves to build into a contract portfolio is different than a mandate. That would create excess uncommitted capacity in the market.

Third, LDCs are concerned about the effect that extra capacity will have on the capacity release market. Under Order 636, the capacity release mechanism is directly tied to the recognition that firm customers needed a means to mitigate fixed costs. Additional unused capacity, which from a planning standpoint would be available at virtually 100 percent of the time, will significantly reduce the value of capacity in the release market, thereby weakening the cost mitigation we received under 636. Such an event would necessitate reconsideration of the regulatory impact we received under Order 636.

Finally, AGA would like to turn its attention briefly to market-based rates. The staff report points out that several proposed storage projects have been delayed or canceled. The staff report also points out that right now we have about sufficient level of storage. We need to meet projected storage growth. LDCs have been meeting with pipelines and independent project developers. At times, we signal our willingness to buy in, and at other times, the economics just are not right for us.

The recent Duke Project, which received a significant amount of attention from LDCs on Texas Eastern and Algonquin indicates our willingness to acquire additional storage. It appears the economics don't make sense. The buyers are not interested or the promoters will cancel or delay that. And sometimes the transportation tied to the storage just doesn't work for the project.

Accordingly, AGA supports the staff proposal to relax or broaden the current market-based rates test to spur more storage development. Another option might be to develop incentives to spur storage development. In a fair market, if a party is interested, it will make a rational decision. The market will bear the market-based rates, and there is no reason to foreclose that option.

Critical for consumer protection are the staff's provisions that discuss assuring that all market risks lay with the projects' owners, and no captive customers are involved in the project. Additionally, periodic review of market-based rate storage services would be an important check on the continued appropriateness of the rate-based authority. The good news is that we are not in a critical situation today, and efforts like today's conference should prevent it in the future. Thank you.

MR. MOSLEY: Thank you, Mr. Oaks. Next is Mr.

Chancellor from Calpine.

MR. CHANCELLOR: Good afternoon. I appreciate the opportunity to provide some input here on these important issues. I am here today representing not only Calpine Corporation, but EPSA, particularly in regard to the concept of reserve capacity that's the subject of this panel.

I would first respond to that, and second I'd like to respond to some of the issues that were raised this morning as to Calpine. Some of the discussion this morning, or some of the desire coming out of this process is some sort of action. I urge the Commission not to take action for action's sake, and particularly in the reserve capacity take no action on that concept. We agree with a lot of the things that were said earlier by Mr. Hopper and some of the others that this is not a good idea that the incentives that would be generated out of this will not improve the market in the long run. We believe that the current market process is acting well. Even though it's really lumpy, it may not come in the same timely fashion to have impact that it does work much better in the long run. We've seen expansions continue, and a whole host of folks here this morning, you know, wanting to expand. So, we think the market will react as things go forward.

This applies not only to storage, but to pipelines. Tennessee just announced an expansion, and these things are continuing. There are ebbs and flows to those expansions, driven by market signals. We urge the Commission to not move forward with this idea.

We also participate in the California efforts on this idea, and maintain that same position in opposition to this concept.

I would also like to address what seems to have become an open myth that generators need not contract for firm capacity or storage. You look at some of the expansions that have occurred here recently. You look at the current expansion. Very significant, most of it underwritten by generation demand. You look at Gulf Stream, the brand new pipeline in the forward market, underwritten for the most part by generation demand. Storage. Calpine was the significant customer in the gas storage field in California. The numbers. I can't speculate on the numbers for all of EPSA, but I can tell you that Calpine, as a large independent generator, spent over a $150,000,000 a year in firm demand charges. To king of counteract that, this whole concept that generation does not pay its bill is floating on the system, I think is incorrect. We may be to the level of firm contracting that some other parties would like it to be, but it's certainly not as you will amount as indicated. We think in the program as kind of outlined or conditioned in the notice might be attractive to certain shippers who do not contract for firm demand, as Mr. Hopper mentioned.

It may also be attractive to storage providers of some sorts and or the pipelines. I was encouraged that independent storage providers are actually opposed to this program. Maybe because, like EPSA members, they're independent.

Just to reiterate our concerns. We do believe in the long-term it will distort market signals. It will actively kind of -- reverse the progress you've made so far in establishing policies for a market-driven process. We agree with AGA that it will damage the capacity release market. The policies you've established, I think someone discussed this morning about shipper must have title, the prohibition against buying calls, contrary to that. The incentives that would be created here will, I think, stifle further expansions as envisioned by the pipelines and independent storage providers. So, we urge the Commission to just say no.

In response to some other things that were discussed this morning. There were several items. One of them is the issue of market-based rates for independent storage. Again, I'm speaking on behalf of Calpine only since we haven't, as EPSA addressed all these. But we plan on doing so in the comments. Independent storage that it truly independent we can see a need for market-based rates on that. Our concern is the lack of independence associated with affiliated pipelines, particularly that concept of what can be done for that storage. How this is utilized in operations and such, and then the rules and regulations and operating constraints that pipelines may put in really force you to take that service. The concept that storage is an option, certainly from just a pure contracting standpoint, yes, it certainly is an option. But from a practical standpoint, as you tighten the constraints, increase penalties, add actual rates with penalties and those type of things, it does not become an option.

The other issue I think as far as rate flexibility, Calpine I think would support the concept of rates, either seasonally adjusted or such as long as it's within a cost envelope for those affiliated structures, set ups. The concept this morning also was brought out that the flexibility in the pipeline is essentially free. I've heard that term. Mr. Hopper pointed out correctly that it is not. When I flew up for this meeting, my ticket didn't say how much I paid in jet fuel, but it certainly wasn't free in order for me to get here. So, those costs are embedded in those rates.

If we need to move forward with working it out, as Mr. Hopper suggested, we're not necessarily opposed to that, but you have to be able to identify those costs and allow independent storage providers to compete against those. But, again, it would come with an attendant decrease in unbundling of those costs from firm interruptible rates.

The last issue I'd like to address is the concept that where things are going and what is the motivation for independent generators to sign up for contracts. I believe Mr. Dickerson mentioned kind of where that might be addressed. It's Calpine's perspective that that's better addressed not in developing a program on the gas side to allow subsidies to occur, but really to address it on the power side as far as how generators are compensated for establishing those firm contracts, either on the supply basis or a transportation basis for storage. That would be the proper place to address that. And on the electric side, and not on the gas. With that, that concludes my comments. Thank you.

MR. MOSLEY: Thank you, Mr. Chancellor. I'd like to start the questioning with Commissioner Kelly.

COMMISSIONER KELLY: Craig, you said that you see the need for market-based rates for independent storage developers. Why did you say that?

MR. CHANCELLOR: I think it will allow additional storage to be brought in. Like I say, I mentioned the load on the gas storage -- and Wild Goose Storage in California was brought up this morning. We are a customer of those. We found value in their being allowed to do market-based rates. My concern really is are they independent. Can that be used in other methods that may have market power where a storage, an independent storage, provider would not.

COMMISSIONER KELLY: Can you anticipate that over time that even an independent storage provider would have market power?

MR. CHANCELLOR: I haven't seen it yet. I think if you set up the appropriate reporting, appropriate rules. I believe Ed Murrell mentioned, rules of conduct and such that are out there and available, I do believe they can remain market-based for the foreseeable future.

MR. MOSLEY: Thank you. Timothy, you talked about the different users of storage, LDCs versus the others. Does the fact that other types of consumers use storage facilities adversely impact the LDCs, put pressure on the LDCs?

MR. OAKS: I don't really believe so. I believe as long as the contracts are balanced on both sides, the LDCs having the appropriate contracts for themselves, and the other users of storage having their own contracts, I see no conflict.

COMMISSIONER KELLY: What percentage of the storage market do LDCs hold? Do you know the ballpark?

MR. OAKS: I believe it's in the report.

MR. MOSLEY: It's in our chart here.

MR. CHANCELLOR: Seventy, seventy-five.

MR. OAKS: I seem to recall it was about 75, 76.

COMMISSIONER KELLY: Do they intend to compete with independents for additional storage or not?

MR. OAKS: Compete in terms of who we contract for?

COMMISSIONER KELLY: Just developing new storage projects.

MR. OAKS: We'll contract with whatever makes economic sense for us. Certainly, there are some incentives to contracting with a pipeline, if it's for reliability reasons, or because transportation might be somehow tied to a proposal. But beyond that, the economics of the project will decide who we contract with.

COMMISSIONER KELLY: Thanks.

MR. MOSLEY: Now, we'll let staff question the panelists. Who'd like to begin?

MR. FLANDERS: I want to know what the panel thought about the contrast between the electric system or the reserve margin requirement and the lack of reserve margin requirement on the gas system? For the electric system, obviously, the power, moving at the speed of light, has a lot to do with it, and you can get very rapid failure modes. But isn't there a need for a contingency analysis standard of some kind on a gas system to assure that full service can be maintained in the face of certain operational contingencies?

MR. OAKS: It would seem to me that the nature of contracting in the gas business actually drives that little differently. Contracting in the gas business is based on some design situation that may occur once in 20 years. Therefore, embedded in that planning decision is a little bit of reserve. Some would argue too much reserve. It is there as a safety factor. Nineteen or twenty years. To add yet another level of reserve above that would just be piling it on in my mind. To continue on, the difference I see between the gas business and the electric business is again the nature of the instantaneous need if a plant goes down on the electric side versus what is essentially a progression of activities, like, for instance if there's a slug in the pipeline, we all know that. We have enough time to react during the winter season. I think it's the nature of the timing.

MR. CHANCELLOR: I'd like to address that. I think we're talking different issues here. On the reserve margin front, a generation standpoint is really a commodity reserve. It's the ability to create that commodity of power itself, the megawatts. Here, we're talking about more the reserve storage capacity and pipeline capacity. One thing that wasn't really brought into the notice here is the issue of you've got the capacity. Who's going to put the supply in there, and who's going to control when that supply, if there is a "supply reserve" available, who's going to say who gets it when? There is, in my understanding, even on the transmission side if you want to kind of relate electric transmission to gas transmission a certain amount of "reserve transmission capacity," but it's been developed. The amount that's reserved is more on the inter-tie (sp?), the seam side of it, moving from one area to the other. The grid operator may reserve a certain amount of input transmission in case a supply or generator load, not load, but generation falls off within his control area, which is a bit different than what we're talking here. The only other amount would be analogous to the amount of transmission capacity on the electric side that maybe out there on a seasonal basis or whatever. Much like on a gas pipeline, they will contract for a maximum amount of capacity. But there's always a little bit more. You need a little bit of slack for just engineering errors or changes in temperature and such that occur. So, I see very fundamental differences between "a reserve margin" and that term used on the electric side than what we're using here.

MR. WILSON: If I could respond to that in a little bit different way. In the electric system, if there's a contingency in the transmission system, you can crash the whole system, and everyone loses service. Even if you have a generating capacity shortage, it's really not feasible to allocate that generating capacity shortage to the particular customers who didn't sign up or didn't somehow support the system and contract for it. By contrast, on the gas system, even if there's a contingency or an excess demand or whatever, your policies and the fact that the system is firmly contracted, clearly allocate the existing capacity to those who supported the system, and the shortage risks on those who didn't contract. So, since we're able to more or less correctly, from an economic standpoint, allocate the consequences of that scene in advance, there's not the same need as there is in an electric system for some sort of centrally provided reserve.

MR. DICKERSON: I think it's--

MR. FLANDERS: Dave, you look like you had something to say.

MR. DICKERSON: I think it's just about all been said. I think there are cost allocation issues that LDCs might have. Plants might have a little bit of concern about excess capacity. I think it mitigates the true pricing signals that currently exist under today's gas policies of having new capacity priced typically at its incremental marginal cost. That's a market signal or a pricing signal that might be disguised in the marketplace if there's not a clear buyer at that specific price for a specific capacity.

MR. FLANDERS: I'm trying to focus a bit more on the kind of peak day operating contingencies. The situation I'm envisioning is that the only customers that are on the system are firm customers. A line blows up. A pipeline blows up. At which point line pack is gone. We're in a kind of crisis situation. The analogous situation on the electric side would be a transmission line goes down. But the system can reconfigure in time to keep firm power service going. I don't see that in a gas system. I see, even though the response time is certainly different, and there may be some contingency time, there just doesn't seem to be any kind of major contingency built into the gas system.

MR. OAKS: Actually, I believe there is. Back in 1994, which tells you how old, there were rolling blackouts in the Northeast. On some pipelines, capacity was cut to 90 percent of our firm entitlements. We were able to manage that by going to our large industrial customers and working deals with them and potentially with oil. Buying their oil and things of that nature to get them off the system. So, each LDC does have other emergency contingencies which often deal with neighboring LDCs who might be on different pipelines. So, there are reliability things LDCs do that provide contingency safety that go beyond just contracting.

MR. CHANCELLOR: Bob, I think what you're saying is certainly could occur, I mean, there's a lot of the grid that has multiple sources of gas. But I think even if you had some sort of reserve capacity, unless you have a completely separate line, assuming some catastrophic event that's going to take that excess capacity out also, so I don't really see that you've gained very much unless you have a duplication, and that's going to be very expensive.

MR. FLANDERS: What about a compressor outage? I guess this is a question for Mr. Dickerson. Do you have flexibility in the design of your system to meet firm service obligations when a compressor station goes down, for instance?

MR. DICKERSON: If one compressor station goes down, we typically do -- really we have operating hiccups all the time, just as any operating system does, and we manage around it. We don't really have redundant units, but as you may be aware, a pipeline system is set up for a given gas day, and we never have for long-line systems like Tennessee coincident peaks all across our system. There are always gaps in the ways the weather fronts move across the country. They're no being taxed in Tennessee. At the same time, we're being taxed in New York, for instance. We have a little bit of redundancy built into that, just with that circumstance. Only in a situation where we were in an absolute, system-wide peak, that we would not have flexibility. As weather conditions come in, we do load up our system. There's a limit to that clearly, but line pack is a very important tool for us in trying to prepare and anticipate for weather events that need to be managed or if we have an operating situation. The other thing we have in the Tennessee case, and this exists for many pipelines today, we have roughly two-thirds of our capacity or our supply on a peak-day basis will come out of the Gulf of Mexico. We have significant amounts coming out of storage fields, coming from Canadian sources, both eastern and western, and a new Stage Coach condition on our system. We have a lot of different pieces. Obviously, we ramp up another sector or another segment to the extent that we have an issue somewhere else. That's done both directly by us and as a reaction by the marketplace.

MR. OAKS: If I might just to say something nice about Jay and the other pipelines in the room.

(Laughter.)

MR. OAKS: To the extent that there is a pipeline grid and one pipeline has a problem, the pipelines are certainly there with their various interconnects, particularly in the market area, to cure things like a compressor failure.

MR. PINKSTON: I have a question kind of along these kind of along the same lines for Jay Dickerson. Is there a concern that the market signals and what appears to be good economic procurement, where a user is relying on or anticipating very high prices to avoid the demand charges year round, is there a concern that those market signals, that that practice will result in reliability problems, and the market signals will lag the need for capacity? If you could provide some observations of your own system in New England last January?

MR. DICKERSON: I just think it could go either way. Too much capacity or not enough because the market signals may not align accurately. One thing that has changed over time, from a FERC policy standpoint, is who is ultimately deciding that the market needs incremental capacity? At what point in time, in addition to all of our customers on the pipelines, the Commission will be assisting market need for a new project. We've move to a new world today, where a contract is essentially a gauge of market need, and you don't have a particular party standing there saying I'm making the decision. I'm making the commitment. I'm deciding that we do need this increment at the incremental price. To me, you lose the connection that we currently have, and I would be concerned with. In New

England, we're anxious to serve New England to the extent it needs to be served. I talked about earlier it being in sort of two segments from our standpoint, the LDC sector and the electric generation sector.

We announced last Friday a new open season that will eliminate our take out reserve margin so to speak up through Pennsylvania. Take that availability capacity at some facilities across New York and into New England, and provide an additional 100,000,000 a day of new capacity from the Gulf of Mexico, including South Texas, which we think will be beneficial for producers, because the south Texas space was particularly negative last winter. We think it would be helpful for them, and we had very extreme locational pricing signals last winter. And we think it's going to be hopefully necessary for that market. In addition to other pieces of what we're offering the marketplace, we're offering over 15 percent capacity expansion in New England. That's more than enough for the LDC market I think to be grown. So, the big question mark to me is what is this appetite for the electric industry for new capacity.

The expansion I mentioned in New England from the Gulf Coast, we're looking at a rate that's within $0.04 of our generator grid. We're committed to fix that, and then be responsible for that cost, and fix it at that level. So, we're hopeful that we found an economic platform that will be attractive to the marketplace.

MR. WILSON: I'd like to add a comment on your question. If there are industrials or electric generators who don't contract for long-term capacity at all, does that mean there's no signal there for new capacity? I don't think it's weak, but it's not no signal. That's because you have marketers in there. They do contract for pipeline storage capacity, and not always with firm customers behind it. So, they're watching the overall market. There's a lot of uncontracted demand. I think that's probably reflected in the demand of the marketers for new capacity.

MR. MURRELL: I'd like to kind of follow up on some of this morning's discussion and ask Mr. Wilson, Mr. Oaks, and Mr. Chancellor, from the customer perspective, we heard a lot this morning about one of the problems with getting a new independent storage project up and running is getting customer commitments and getting longer term contracts. People are talking about how wonderful it would be if they could get just a five-year term. I'd like to hear to the extent you can describe for us kind of where your companies are at with your contracting practices and why, in terms of the term of the commitments you're making, and your perspective on supply and demand of capacity and storage in the marketplace.

MR. CHANCELLOR: I'll go first. I do believe if my memory is right, we signed up for a five-year contract with Lodi. It's not that we won't do those type of deal. The demand by electric generation is really going to be driven by our own contracts that we have underneath. It's going to be a measure of how much firm power sales we have. That's as simple as it can be. If you don't have a contract for capacity that's going to call on that, or you don't have a firm contract that goes beyond a year or two, we can't match up anything beyond that.

MR. MURRELL: Do you need to have that firm commitment to sell on the other end?

MR. CHANCELLOR: I think at this stage of the electric market, yes. It was, I think, a different situation for the collapse of the market. It depends on your view of the market. Where it's going to be. We were contracting this for Calpine, you know, beyond some of those contracts, but can't do that at this point in time, just because of the state of the market. There is also I think a little bit of misunderstanding I think if you look at from a tolling standpoint. If we can do a tolling type agreement, then if it's an electric utility or electric distribution that is tolling that facility, then it's really maybe contracting underneath of them for that firm delivery. You can't just look at it as Calpine or Constellation or one of the other generators signed up for that firm capacity because it may have been or may be currently be provided under a tolling type agreement.

MR. OAKS: From an LDC standpoint, it's truly a state-driven issue. In states where the customer choice regulations have been stabilized, the pendulum has swung to the extent that LDCs are no longer fearing that they're going to get caught with capacity that they have that is essentially unused as they lose the merchant function to marketers, and there's no assurance that that same capacity will be transferred over to the marketers. The length of contract has certainly shortened over the years. If one of those conditions crystallizes, if one -- some knowledge of whether you're going to be in the business until whether you can get recovery of contracting capacity, in those states, it's not unusual for contracts to go out five to ten years now. It's really a state-by-state issue in my mind.

MR. WILSON: I would just add to that that I think it also reflects the fact that the value of storage is highly uncertain right now. There's three different services that we use storage for. There's peak-day deliverability. There's the summer and winter shifting. Then there's the trading value, the in and out multiple terms. Each one of those is very uncertain right now. I think in Calpine's filing, they show that the summer-winter difference with the NYMEX had been hanging around $0.30 for actually a long time. I checked, and it goes back a couple of years. And in July and August, it jumped up to $0.60.

If you look at the extrinsic value and you report and suggest it's discounted 50 percent, I wouldn't be surprised if it's even more. That relies heavily on the degree of volatility in the market, which is much higher than it was in the past, and the volatility depends upon a whole lot of things that may change in the future, and may go down. I think it further reflects the fact that the value of storage is made up of these different components, each of which is different and uncertain, and has various substitutes. So, it's just very hard to get a good handle on what storage is going to be worth three years out or five years out.

MR. MURRELL: I noticed in Mr. Hooper's presentation, he's got a chart in here showing the NYMEX futures prices out to January '09. It shows that seasonal pattern, but slowly going down, and he's labeling this as kind of a containment. Does that have a riskier commitments of longer term commitments to storage?

MR. WILSON: I think that reflects that the market feels now it has for years that we're going to see new sources of supply, and we're going to get back to more reasonable prices. It reflects expectations of LNGs, finally bringing the prices down a bit. The summer-winter differential there, if you actually look at a few more years, you will see the same thing we saw for '05-'06. You had a summer-winter differential that was quite low last year, and recently it's increased quite sharply. But that could go down again in a few more months. It's hard to predict.

So, I'd like to follow up on Ed Murrell's question from a customer of storage providers perspective. That gets back to the proposal or the advocacy of market-based rates. What from a customer perspective constrains those prices? What choices do you have, alternatives, to purchasing storage services from storage providers? How concerned would you be if we said all storage could be done at market-based rates?

MR. OAKS: Again, I guess the economics don't change from my standpoint. If the rates are too high, we may look for alternatives, and those alternatives might be just from transportation, with the hope of using the capacity release market to mitigate the additional costs. I'm going to make that judgement. I'm going to look at the economics and make predictions about what the revenues from the capacity release will be, and I'll just lay those next to each other. Whichever is the most economic sense, I'm going to contract for. The driving factor is EGI's case, I'm going to need capacity, and I'm just going to find the cheapest capacity available, whether it's market-based rates or whether it's cost-based. I might fight that in specific proceedings, but ultimately I'm going to look for the lowest cost.

MR. CHANCELLOR: You used the term all storage, and it's our position that it really should be truly independent storage, if allowed to do market-based rates, particularly where you have vintage storage already in place that will act as a mitigating factor if that market is beyond the 75 percent that the LDCs already hold is available to help mitigate any market power that they may have. The penalties and everything else associated with balancing the pipeline would also drive those prices. It may not be more of a mitigating factor. It may be a driver of actually increasing those prices. I think as you look at implementing those rates, you need to really focus it on loads and the interplay between the existing utility storage versus the independent storage.

MR. MOSLEY: Any more questions from staff?

(No response.)

MR. MOSLEY: Let's open this up to the audience for Q&A. Again, please step up to the microphone and identify yourself and what organization you're with, and keep the questions to the topics for panel two. Anyone?

(Laughter.)

MR. MOSLEY: Okay. Thank you very much, gentlemen.

MR. NICHOLS: Can I ask a quick question since no one's going to step up to the mike. You hear a lot, as you recapped to Mr. Chancellor, that electric utilities or the electric generators are getting a free ride on the system, and you discount that as an urban myth. We have lot of different roles here at the Commission, and one of our big roles is obviously a judicial type function in which we have to sort out where the truth is in this. What's a good way to analyze that issue? What's a good way to determine where the balance is?

MR. CHANCELLOR: The 5.7 certainly have the information as to who the customers are. If you can obtain that information on a non-company specific level, it would certainly help understand the level. But I think it also you've got to look at the generation demand, and what you expect it to be. Just because there is generation in a certain area of the country doesn't mean that it's all going to run at the same time. There really is excess capacity out there in certain regions. So, to elicit it from that angle and say, look, 90 percent of the generation is operating on an interruptible basis, well, if your electrical reserve margin within that area is 50 percent, and that is 100 percent on the gas side, you may not really be at any risk from a reliability standpoint of not having firm capacity. I mentioned kind of a tolling reserve. It makes it a little bit blurry as far as who actually is holding that capacity compared to who is looking at generators.

MR. NICHOLS: Thank you.

MR. HOPPER: Can I say one more thing about commodity-based rates. That is this, in this market the market is transmitting signals that storage should be built. Where is a different question and how much is a different question. But in that kind of a market, as we saw in the gas-fired electric generation market, projects will get built, and they'll probably get overbuilt. As we have seen time and again, bad decisions will be made to the benefit of the consumer, and I believe that will be the case in the storage market. I don't know about pipeline capacity, but I believe that's very much the case in the storage market. That is the time for customers, particularly end use customers, to contract for storage and lock in a price that they find is acceptable so that the recontracting issue can be mitigated at that point in time. I guarantee you if anybody wants to come sign up for a 15- or 20-year contract at a fixed price at one of our facilities, our door is open. Come see us. And I believe that if the market's willing to do that, that's the opportunity, and that's the time at which they can address this issue of market power. Do it now. Don't wait.

MR. WILSON: If I can just add. I think Mr. Hopper explained why we don't like long-term contracts right now. Two or three years out, you've got the coming storage glut, and that will be the time to go long.

(Laughter.)

CHANGING ROLES OF INDUSTRY SEGMENTS AND HOW THAT AFFECTS COMMODITY PRICE VOLATILITY

MR. MOSLEY: Thank you, gentlemen. Without taking another break, let's go directly to the next panel, Panel Three.

I'm going to introduce the speakers in which they're going to be speaking, starting with Scott Smith, Senior Vice President and Partner of Lukens Energy Group; Greg Rizzo, Group Vice President for Duke Energy Gas Transmission; Thomas Price, Vice President, Marketing, Colorado Interstate Gas; and Mike Anderson, Director, Energy Supply Planning, at NiSource Energy Companies.

Mr. Smith, if you could please get started.

MR. SMITH: Thank you for the opportunity to speak today. Just -- we are a management consultant group, providing strategy and regulatory support, asset valuation, and risk management to the energy sector, with a focus on natural gas, LNG, and power elements of the business. We also do license storage and valuation software to many of the large storage operators in North America.

Just a real quick overview of what I'd like to cover today. It's more trying to give a perspective of what's happened in the last couple of years with volatility, trying to kind of maybe define some standard definitions of that.

I think about how these trends in prices involve and how will they impact the value of storage, at least historically, and they've also moved forward to understand what's happening in our industry and what the implications may be to volatility and prices moving forward, and then finally I'll close with some comments and implications for future policy decisions.

First, to start off, viewing trends in natural gas price volatility. As everyone knows, we've seen gas prices the 2002 time period at this $3.00 level move to prices that are well above $6.00 today. Almost a hundred percent increase in prices. However, we have not seen that corresponding increase in volatility. When you look at Henry Hub contracts and contracts at NYMEX, the average volatility in 2002 was 56 percent. That bumped up to 68 percent in 2003, and then in 2004, here today, it's gone down to about 50 percent. In essence, over those last three years, a volatility increase of about six percent, looking at historically, the Henry Hub volatility. The other thing that's interesting is that there's a fairly significant price spike in 2003. That's par of that data that I obviously showed to you. More than a two- or three-day period where the prices peaked up in 2003. Volatility over that time period was essentially flat.

One of the questions, then, becomes what is volatility, and how do I define it. I think that's a pretty key element. Volatility in kind of a mathematical sense is essentially measuring the percent change in prices. What it doesn't necessarily represent obviously is what those absolute changes are. So, if you have volatility that's constant, with the increasing gas prices, then those average price changes will increase.

So, we may ought to step back. Let's look at prices and what's happened over the same time period, and how they've changed from year to year. The measure of volatility in percentage terms, as we go back in 2002, we can see the average absolute price differences. Volatility, day-to-day changes in prices of approximately $0.09. That jumped up to $0.16 in 2003, and it has fallen back to about $0.12 in 2004 here today. There has been some small increase in volatility when you measure it in absolute terms, but it hasn't been substantial. That's again looking at NYMEX. It's looking at Henry Hub and prices on the Gulf Coast.

What happens when you look at market areas locations? What we did then is look at historical prices supported by Platt's Gas Daily. I think we looked at New York Algonquin, Chicago, and California border to measure the volatility trends over the last few years, and we found some mixed results. We saw volatility of Transco Zone 6 increase from approximately 80 percent 2002 to well over 200 percent in 2004 year to date. Very similar results in New England. You see volatility increase from approximately 100 percent in 2002 to 260 percent year to date to 2004, a very substantial increase in volatility regardless of how you measure it for those northeast market locations. However, we've seen the opposite in Chicago and California. When you look at Chicago prices, we've seen a volatility decrease from 60 percent in 2002 to slightly over 50 percent year to date 2004. The same thing SoCal border prices. Prices with volatility gas, daily volatility was approximately 90 percent in 2002. It's now decreased down to approximately 60 percent year to date 2004. So, varying differences across the country in volatility trends, as well as there's also some element of how exactly do you want to define volatility.

I may be biased a little bit in my measurement of volatility from the standpoint of what it means for storage. Essentially, it's what my comments are based around.

Let's look at another element of what's happened with prices and look at the forward price differential, the summer to winter spread, looking forward, not looking historically, but looking at it at a given point in time and looking forward and seeing what that summer to winter spread has done. If we look at 2002 to 2003, using kind of a gas year example, so April 2003 to March 2003, the average over the summer-winter spread is approximately $0.70. 2003 to March 2004, we saw that drop to approximately $.50, and if you remember during last summer, we had issues about whether storage is actually going to be full, and we were competing against what I would argue is against the summertime demand for that storage injection, which collapsed those price spreads. What we've seen so far in 2004 is just the opposite. We've seen that forward looking summer to winter price differential increase to average approximately $0.80, which effectively, through late September of this year, includes a substantial price run up that we've talked about that happened in late September or October, where the summer-winter price spreads were well in excess of $1.50. You can see from the standpoint of just what's happening in the winter-summer price differentials, those are very substantial as well, and again I thought they developed these estimates.

What are the price trends over the last couple of years mean for storage values? How do the values change in the last few years? As they're addressed in the report that staff has developed on storage, there's many different ways that storage is utilized as well as how it's valued. It's used for essentially a hedge for utilities to buy gas for the summer and pull out in the winter emergency supply peaks et cetera. It's also used to arbitrage prices. So, one way of measuring the value of storage is what the value of arbitraging prices are through time. That's a fairly commonly accepted methodology to understand the storage values in the short-term perspective.

Storage value, as we talk about it, is comprised of two components. What we call the intrinsic value is the value that's available in the market today, which essentially is represented by the summer to winter spread.

It's also governed by extrinsic values, which is essentially what volatility does to storage. How these prices may change from day to day, and how that may add additional value to holding that asset and being able to capture these peaks or these troughs of prices depending on what you inject or withdrawal position in addition to those two elements of value derived for what we consider value storage.

What we did is we used our evaluation tool that we have developed at our firm to value storage and have the trended storage value over this two- to three-year period, and what we saw for a fairly high flexible reservoir storage asset. That value is increased to approximately 20 percent from 2002 to 2004 year to date for high flexibility storage. Salt dome storage is essentially flat values over that time period, so storage values, at least on the Gulf Coast, given that history have been flat to slightly higher.

In those scenarios, one of the elements that's driving is we've seen greater increase in the extrinsic value and the optionality. We also see the higher impacts because they have greater carrying costs and greater carrying utilizing that asset.

What about the impact of storage values and market locations? It's not very hard to understand. That's the trend of the higher volatility we're seeing in the Northeast as we've seen, as well as very high winter basis that the value of storage in those locations is greater than that on the Gulf Coast. The trend has been similar as to what we saw in the reservoir storage values increase approximately 10 to 20 percent in those particular regions. It doesn't exactly track with how great volatility is increased, but they've still gone up.

Alternatively, you can look at what's happening in the Midwest. If you had a sample storage field, sitting on the Chicago market, the values are relatively flat; whereas, in California, we've seen the potential for storage values to drop, considering the price behaviors at the SoCal border.

We are now shifting gears to understand where we've looked at volatility. What do we think about moving forward and what are some of the things happening that would impact volatility. What we believe is changes in the fundamental factors in our market are going to have substantial impact in gas prices, as well as volatility, and these factors would include supply-demand balances. What fuel substitution capabilities are. Pipeline infrastructure as well as pipeline congestion. Storage infrastructure and the market liquidity.

We start thinking about gas supply and demand. We expect gas supplies from North America as traditional sources to decrease approximately four percent in 2005 to 2010. At the same time, we see demand increasing approximately 10 percent over that time period, so obviously we see a growing gap. We project that gap to be filled by increasing LNG reports of approximately 9.3 BCF by 2010.

What are the other elements associated with these LNG imports is not knowing only where the location is, but will that be imported as more of a base load supply, trying to make that LNG flow into the market regardless of what supply and demand may be, whether it be on the Gulf Coast or in the market area.

As I mentioned, the LNG load in the market area has its own unique elements to it. There could be issues associated with pipeline bottlenecks, delivering into the market area. The pipeline infrastructure wasn't necessarily built to handle large volumes of gas delivered to the market. It's built to deliver gas from the Gulf Coast up to the market regions or the production of the market region, and I'm not saying that's going to happen, but that's an issue to understand, as well as to the extent that there's a substantial amount of increase in LNG deliveries in the Gulf Coast. Is there an adequate infrastructure off short to handle all those increasing deliveries.

We start thinking about consumption, what our trends are there, and the potential implications to volatility. One of the key impacts is that we've seen industrial consumption has dropped approximately 14 percent from 2000 to 2003. The important element to this is industrial consumption had some price elasticity. It basically varied as prices went up and down. To the extent we've lost that load and also our belief is that that growth was relatively slow and low, we've lost an element of our market that could help dampen that price volatility by reacting to prices.

Alternatively, looking at natural gas for power generation, we believe it's going to grow, and it's going to grow almost 20 percent from 2005 to 2010. This is an area that we do see some very interesting impacts on volatility and what we believe is going to cause increased volatility, the shift in demand pattern. Obviously, what happened with increasing demand in summertime it will cause competition to move forward for summer and winter injections for storage as well as impact volatility. We've also seen electricity demand to have very low price elasticity when the system is stressed, which eventually could impact when those plants have to run in their demand for natural gas. Again, as I mentioned, we have impacts to increase both volatility and put pressure on the seasonal spreads.

One other element we think is important is the scaling back of the natural gas marketing and trading sector and its reduced liquidity at trading and providing gas pricing alternatives. We believe the realignment of this industry was necessary, but we also believe that this element of our sector of the industry helped manage this volatility of matching base load supply to variable demand. We think that had a very key element to helping mitigate volatility in the past.

So, start thinking about what all this means, what the historical trends have been at least in volatility impacts on storage, as well as what we see moving forward. And I'll give you my closing comments.

Obviously, we're projecting that volatility will increase. We believe it will be very much local or a local or regional basis. We have seen very little impact or very low impact to what's happened in our gas market in the Gulf Coast, and obviously we've seen dramatic extremes on the Coast. We believe volatility winter price spikes will grow. We've had some of that happening in the Gulf Coast, and it's happened right now as we've seen up in the Northeast, which implies essentially a need for additional storage, both in the market area additional pipeline capacity and increasing LNG supply being delivered by the market area. The recent stagnation of independent storage development may be attributable to the fact that we have a properly functioning market. The current arbitrage value of storage in the Gulf Coast is not sufficient enough to justify additional storage development. So, to remedy that, obviously to the extent that we're going to rely on the market to help drive that development, increases in volatility and seasonal price spread will drive potentially increased development in storage.

Alternatively, those interested in trying to mitigate their exposure to that long-term contracting for that storage capacity to mitigate their exposure. We believe willing LNG supplies may impact natural gas price volatility depending on where the import terminals are located. The transition of a healthy marketing and trading sector is needed to help mitigate the volatility exposure associated with the mismatch of base load LNG imports to seasonal fluctuations in demand.

Finally, the last comment. We believe the market should be allowed to function in terms of when and where infrastructure changes are needed to mitigate natural gas prices and volatility. They're all alternatives that exist today that people can contract for to mitigate their potential exposure to volatility, whether it be independent storage to rate-based storage, new pipeline structure, or LNG terminal storage. If the value proposition is solid, we believe long-term contracts would follow, which would facilitate development and construction. Thank you for listening to my comments.

MR. MOSLEY: Thank you, Mr. Smith. Next we go to Gordon Rizzo from Duke Energy.

MR. RIZZO: Let me thank the Commission and staff for continuing to sponsor these types of outreach programs and for the opportunity to speak today.

A little bit about Duke Energy. Duke Energy is a leader in the infrastructure development. Duke Energy has in excess of 17,000 miles of pipe. Collectively, it has over 250 BCF of storage. That's North American storage, both in the U.S. and Ontario, Canada. And over the last three years, we have spent over a billion dollars in gas transmission and storage infrastructure.

By the way, I have prepared remarks, and I also have provided kind of a outline of what I was going to say today. At least for those of you sitting at the table, it's probably at the very bottom of your pile there.

I'd to start a little bit with the 636 and 637 and just really say that has really been a great success. It was all about choice. It was all about creating a fungible type of transportation, increasing flexibility, providing more competition, new industry players. It has all worked, and since the implementation the market has grown.

That kind of brings us to the problems that are facing the industry today. Really, there's three of them: there's tight supplies, price volatility, and inadequate infrastructure. Actually, I've identified the same three problems that I'm now speaking about. In terms of how do you meet these challenges, there's a lot of work that's already taken place. Number one, in regard to the tight supplies, I think the Commission in that regard was very visionary and saw that coming. They issued the Hackberry decision I guess three years ago. That certainly has provided an array of LNG projects, and it looks like that's going to work out.

In terms of price volatility, you've heard the panelists on the first two panels speak, and I think the suggestion has been if market-based rates for storage were to be applied, the sense is that we'd see more storage developed, and storage is going to be a very good tool to address volatility.

The issue I'd really like to speak to you about for the rest of my time is inadequate infrastructure of the pipeline grid. The point I really want to make here, and if you happen to have seen my presentation, you've seen the three-legged stool. I think to be able to address the nation's energy problems in the natural gas industry, all three things have to be addressed.

We have to have additional supplies. We do have to have additional storage, but we also have to have more pipeline infrastructure. If any one of those components doesn't occur, the good that the other two do is frustrated. All three have to take place in terms of natural gas pipeline infrastructure.

One thing I'd like to talk about in terms of market area expansions that I think sometimes are overlooked is any time a pipeline expands its facilities in a market area, it creates a bid for the whole market. First of all, you're bringing in more infrastructure. You're doing something to alleviate a pipeline constraint, so you're reducing costs, reducing volatility in that market area. Scott was talking about some of the extreme volatility of pricing that you saw I guess in the New York region off of Transco. The Boston-New England region off of Algonquin and the fact that that volatility had increased, the reason being that those happened to be two of the regions of the country where there continue to be constraints. As long as you have pipeline constraints, you can continue to have higher volatility, even if you add storage, even if you add additional LNG. So to complete the solution all three things have to take place.

The second thing is any time a pipeline adds infrastructure to its system, it is creating a benefit of increased reliability and increased flexibility for all participants--existing firm customers, new customers, et cetera. The reason being you have more infrastructure in the ground. If that new shipper comes, the facilities are built. The day that that shipper is not using those facilities, it's still available to the rest of the system.

Order 636 and 637 with capacity release, forward haul, back haul, segmenting, et cetera, all have taken care of that to see that the pipeline infrastructure is fully utilized. As that occurs, even if it's built for shipper A and shipper A isn't using it on that day, it is benefitting all the other remaining shippers on the pipeline grid. Increased infrastructure has a huge benefit for the whole pipeline system. But I think sometimes the way incremental pricing has taken place for a new project, the costs of that benefit probably haven't been equally shared.

Let me flip over to my next slide. The real point I want to make is right now I think the industry is really at the crossroads or at the intersection of two FERC policies, and I think all we need as an industry is just a little bit of clarification.

First off, you have 636 and 637 and essentially what it created was a single gas market in any particular region, a lot of transparency of pricing, and a really a single delivered price, be it Transco's Zone 6, New York, non-New York, Texas Eastern, Algonquin, City Gate, Tennessee, whatever it happens to be, you have a particular price in a particular region of the country. That way, 636, 637 have been immensely successful.

We also have the pricing policy I guess that came out in 1999. In it, I think it was attempting to balance what the Commission's policy on pricing should be going forward. I think what it said is there would be a presumption for incremental pricing unless the new facilities that you're bringing in provide an overall system benefit. I think the crossroads we're at right now are how do you apply the system benefit. You can apply it on a very narrow basis, and say it's only a system benefit if when you build those facilities, it drives down the average cost of transportation on the pipeline system. If that's the criterion, that almost never will happen.

New facilities are going be priced 99 percent of the time at a price higher than your current system is going to be. So, the incremental cost is going to tend to be much higher. The other way to interpret what the system benefit is: do you take into account the benefit of reduced volatility of lower pricing for gas delivered in a whole region, increased reliability, increased flexibility. If you do, in many cases, the incremental facility ought to be priced on a rolled in basis for the pipeline.

Let me flip the page one more time. I've tried to kind of give you a bit of an example, and I'm going to try to work it in such a way that it illustrates the point. What you have here is just an illustration showing a given commodity cost for an incumbent shipper. Let's assume the shipper is very concerned about reliability. They also have storage, and they also have subscribed to firm pipeline capacity. In this particular case, the delivered rate is about 650. Let's just say the last couple of winters have been very cold winters, and the markets off of this pipeline now are very constrained. In the gray market, and there's been a lot of volatility in the last couple of winters, and in the gray market, the going price for delivered gas is now 750. Let's just say in this area, you have an electric generator, and that electric generator, he has now received a pricing signal from his ISO that says we would like you to firm up your gas supply, your storage, and your pipeline capacity. We want you to be firm, firm. We'll give you the appropriate pricing signal so that you can now afford to roll in and to buy pipeline capacity and gas to have your electric generation reliable all the time. He's willing to do that. He now comes to the pipeline, and the pipeline says this is great. We would love to firm this up with you. This is a very constrained part of our system, and it's very expensive for us to expand it. But if you're willing to sign up for the capacity, we're willing to do that. And it just so happens that the incremental cost for the pipeline is, in this case, the first day, it's a dollar above what the system rate is. We're willing to do that, and that will give you an effective delivery cost of 750. The electric generator thinks for a moment, and he says, okay. That happens to be what the new market price is for delivered gas. I was paying that last year. It looks like I'm going to have t pay that this year.

I'm willing to do that because I'm paying no more, but I know that I have from capacity, and I could be reliable on the ISO grid. He goes back. He talks to his management team, and he calls them back the next day, and he says, you know what, Greg, I didn't really mean what I said the other day, because as I think about it, I realized one thing: if I sign that contract, and if you build that capacity, and you alleviate that constraint on your pipeline system, the gray market price for gas delivery next winter is going to drop because that constraint doesn't exist any more. And so, while today the prices is 750, and I agree if you don't build anything in the next year, the price is going to be 750. If you do build it, and if I agree to pay you that price, where my delivered cost is 750, that price is going to drop lower, to 650. I can't afford to do that. I will be uncompetitive. As a matter of fact, I will be at a competitive disadvantage to the generator across the street who continues to buy non-firm delivered gas to generate his plant, because next winter he can get it for 650, and my delivered cost is 750. I can't do it.

Thus, there is no contract. There is no infrastructure built. We've solved the problem by bringing a lot more LNG into the grid. We have no storage into the grid. But we can't build the infrastructure to get it to where it needs to be.

And in that market region, you still have the same problems of high prices and high price volatility. So, what is the solution?

I think the solution is just simply the recognition that expansion of the mainline facilities do benefit the entire market. All that needs to be done is -- all we need is the Commission to clarify the existing pricing policy to make it clear that it will reflect the benefits of reduced price spikes, greater flexibility, and improved reliability to justify rolled in pricing. That concludes my remarks.

MR. MOSLEY: Thank you, Mr. Rizzo. Mr. Price.

MR. PRICE: Thank you. I appreciate also the opportunity to be here this afternoon. Going second to the last one of the advantages or disadvantages, I'm not sure, is that a lot of the comments I've prepared for today's talk have already been shared with you. You can take these, a lot of them, as a reemphasis, and I will be giving a Lockie (sp?) on a lot of these topics.

The relationship of price volatility, purchasing at hubs, and the relationship of gas needs and electric generation to potential price volatility. As a way of background, I've been employed at CIG for nearly 25 years. Consequently, I have witnessed the challenges of building new storage pipeline under several regulatory frameworks.

Demand in our region is predominantly space heating, and consequently very weather sensitive. Also, production in the region far exceeds local consumption. Any gas not consumed locally must be transported to markets to the west or east. It's very helpful that the Commission is reviewing its policies to investigate ideas which may help to minimize volatility over the next several years. Review of recent history in the Rockies clearly shows that infrastructure adequacy is very important in minimizing commodity price volatility in our region. Besides seasonal price volatility that results from demand changes experienced elsewhere in the nation, the Rockies have seen considerable wellhead price volatility in the past as a result of pipeline capacity expansions lagging behind supply development.

Regulatory changes in the recovery mechanism of new capital projects, along with changing roles of the industry participants has made development of new projects particularly challenging.

Perhaps the most fundamental regulatory change affecting infrastructure development over the last decade is the shift in the financial risk for the creation of new capacity. In the pre-636 regulatory model, when the pipeline served is the central aggregator and planner for capacity, capacity expansions were proposed and approved based on market fundamentals. It is showing a public convenience and necessity could be made, a pipeline would be given a 7(C) certificate, and was generally allowed rolling rate treatment, passing the expansion costs due to existing new customers alike. In this environment, the sometimes relatively minor costs to accommodate a small overbuild for future growth or redundancy in case of a facility outage was often viewed as prudent.

The relatively small price premium passed through evenly to all pipeline customers was considered balanced when weighed with significant system benefits of the increasing reliability and market optionality it provided. Today, before we can file for a new expansion, we need to find contractual support in the marketplace. With the changing role of our shipper base, that support can be very difficult to come by. Being in a gas rich area, we need local LDCs that can second gas at a downstream hub to balance weather fluctuation versus holding upstream capacity into producing basins. On the other hand, LDCs in the mid-continent or western states have generally not found their state PUCs accommodating in supporting recovery of long-term contracts on pipelines twice removed from their market. Likewise, the marketing companies are virtually non-existent in the long-term transportation market, particularly since 2001. This has left the financial burden of planning for and building new pipelines disproportionately falling upon producers and pipelines.

Cheyenne Plains is a good example, where we did finally receive 10-year contracts from a largely producer base to build a desperately needed expansion out in the Rockies. This project, however, was three to four years in the marketing phase, and it was not until wellhead prices in the Rockies were $2.00 per decatherm below that in other regions that the final market support came forward.

Regarding the risk profile, once Cheyenne Plains anchor contracts expire, El Paso will hold a hundred percent of the financial risk of that pipeline for the approximately two-thirds of the undepreciated investment.

In the meantime, the parties that subscribe to this capacity could find the market value of their transportation trading below the incremental cost of service that they paid to get the expansion built, particularly on an average day basis.

The reason for this is, even small surpluses in the capacity market can greatly reduce the underlying market value of transportation for all routes in the region. This is the reason we are very concerned about the concept of reserve margin for the gas industry. Unlike the electric industry, where capacity can be added or subtracted with the flip of a switch, once it interstate gas transmission capacity is placed in service, it's available day in and day out on a firm or interruptible basis.

While we believe redundant or reserve capacity will provide many of the advantages the Commission is seeking in decreasing price volatility, we will do so at too high of a cost unless it is accommodated with other regulatory changes. The Rockies' history has shown shippers and pipelines alike that even slight overbuilding can severely depress the market price on all existing pipeline capacity, leaving the pipes at a considerable risk for recontracting or renewing expiring contracts.

In particular, the Commission should revisit the pricing and service provisions of short-term firm and interruptible services in concert with any proposal on a facility reserve margin.

I'd like to comment in a little more detail on the process of purchasing gas at market hubs in favor of upstream capacity. While this process can appear efficient and cost effective in the short run, it certainly exposes the purchasing party to greater volatility. Price competition within supply basins is very healthy. But competition at a market hub can be reduced if the capacity into that point is held only by a few players. We believe the Commission has adopted a policy which may place too much emphasis on mileage based rates in the marketplace, and that the Commission's policies may encourage shippers to buy solely at market hubs to the possible detriment of the shippers. Now, more than ever, with the exiting of the market companies from the marketplace and the corresponding reduction in liquidity, coupled with the gas supply environment, which is very tight and may be short, it is advantageous for gas buyers to have the opportunity to purchase directly from suppliers at locations upstream of the market hub. We see significant benefits to shippers, both from the establishment of direct working relationships with producers and improvement in the knowledge of direct basin supply market intelligence which comes from staying active in the upstream marketplace, instead of relying on the potential vagaries of the market hub for all and individual shippers' gas needs. Active participants in the upstream market enjoy the benefits of staying more into with the production trends and can anticipate and react more quickly to develop shortages of supplies.

Many consumers in the marketplace today are simply becoming price takers, reacting to market volatility instead of planning and positioning to avoid it.

Another significant source of volatility we see in the west as elsewhere is the rapid daily and hourly demand swings created by gas-fired electric generation. These swings create extreme operational volatility and consequently often price volatility on the grid. We've designed a successful model in CIG that permits us to serve gas-fired electric generation markets without interfering with the rights of other capacity holders. But we continue to study and improve our thinking on these difficult issues for the rest of our pipelines. As we meld together the electric and gas industry with the significant industry of gas-fired generation load, we see a need for more realistic identification and allocation of the cost to serve these highly variable verb (sp?) profiles. We find it improper, for example, for the Electric Reliability Council to count as firm from electric generation facilities that have not purchased a firm service from a pipeline supplier that allows the FERC can provide a needed leadership role across the industry segments on this issue.

As our load demands increase across the nation, it is naive and dangerous to assume that the capacity to field these facilities will be there when needed, and the firm service which recognizes the unique operational demands of generation placed on gas pipelines is not purchased.

In closing, I'd like to reemphasize a few comments and ideas we feel address some of the issues I've identified. To help with more timely development in the siting of new infrastructure, we'd like the Commission to considerable more liberal pricing policy for expansions. Any new expansion that enters the market with unsubscribed capacity should be permitted to price its IT or short-term firm at significantly higher prices while offering recourse rate for any shipper willing to take the capacity for a year longer. Considering any requirements for reserve margin, the Commission needs to revisit the wisdom of using a hundred percent load factor rate determination for the development of IT rates and determining the appropriate pricing for short-term firm capacity.

We need to give shippers an incentive to sign up for capacity which benefits the market in total. With respect to the trends of purchase of supplies at hubs, we believe that the Commission needs to allow greater flexibility to deviate from the policies of mileage-based rates.

Lastly, we believe it is important for the Commission to actively encourage electric generation shippers, ISOs, state regulators, and reliability councils to understand the importance of firm transportation service for electric generation when that generation is being counted on in the marketplace. We recognize there are many unique factors which determine the proper terms and condition of service and the proper terms of the pricing of this service which best meet the operational needs of the generators on each pipeline. But the significant reliance by the electric industry on interruptible service is not only -- adds volatility to the marketplace, but sets the stage for future market dislocations. Thank you.

MR. MOSLEY: Thank you, Mr. Price. Mr. Anderson.

MR. ANDERSON: Thank you. My name is Mike Anderson, Director of Supply Planning in the Energy Supply Services Departments for the NiSource Distribution Companies. The NiSource Distribution Companies are 10 LDCs that operate in the Midwest and eastern U.S. Combined we serve over 3.2 million customers at retail.

According to the numbers that were in the staff report on storage, we contract for about four to five percent of the working gas in the country today. That's about 165 BCF in round numbers.

I'd like to express my appreciation to the staff for their report. I find it useful, and I found it informative, and want to add my appreciation to those that have addressed before. I want to also give my thanks to the staff and Commission for allowing the NiSource Distribution Companies to be represented on the panel today.

Previously, Mr. Oaks, representing AGA, talked a lot about what LDCs look like. As Mr. Price talked about being the last one on the panel and the last speaker of the day, there are lot of things I had planned on talking about that have been talked about already, but hopefully, I can add a few traditional insights into LDC use and maybe provide a couple of key points from a party that relies heavily on storage and use of storage on a day-to-day basis to serve its customers. Storage is a vital resource for the Columbia Distribution Companies. In total, about 50 percent of our six-plus BCF a day city gate capacity comes out of storage. We have in excess of three BCF of daily deliverability of market area storage. In addition to that, we have about 230,000 decatherms of market area storage, and we have a small amount of on system storage as well.

Approximately 40 percent of our seasonal customer requirements are provided by the storage. Nearly all of that storage that we contract for is traditional single-term intermediate storage, as Mr. Oaks described it. We know from our experience in operating the system since 636 that seasonal peak days can occur very late in the wintertime, and that's very important in terms of the operations of storage; and, in fact, we've seen that in the later half of March before. We also know that we can have very cold weather. Those are conditions that make management of storage critical to the least cost requirements in the NiSource LDCs. The NiSource LDCs are also very active in retail access programs. We have customer choice programs in just about every one of our operating companies, and through the operations of those programs, through capacity release, the provision of balancing services, we're using storage to provide access to those retail marketers in our choice program as well.

However, I think it's important to know and understand that even with those choice programs, the LDCs continue to bear the responsibility as the supplier of last resort according to various state jurisdictions in which we operate.

Turning to the staff report, I think that we are very much in agreement that there is no emergency regarding current storage levels. But given the strategic nature of storage use, it makes sense to begin these discussions now to get ahead of the curve and ensure new ways that storage is available in sufficient quantities to meet the needs of the market on a going forward basis.

One of the concerns we do have, however, is that we believe that no one should be required to build storage facilities based on a particular cost structure that fails to meet an internal financial analysis if that party is building the capacity. I think that consequently if storage capacity becomes scarce, the Commission can consider incentives to spark construction. However, the cost of these new facilities should not be forced upon customers unless those customers, those facilities, certainly meet the net benefits test.

We have a couple of important points that we'd like to make about the report itself.

As was stated earlier, I think it's important that we do have a tightening of that range of what the working gas is. I think that's affecting volatility, because I think when parties are in the marketplace, and they're seeing that storage is full, that's affecting prices in terms of how people are looking at the marketplace. What are we going to do with gas if we can't get it into storage in some of the shoulder months. I think it does affect volatility. I think it's important that we try to get those numbers sharpened.

Currently, I think there's too much of a gap in those estimates, so we certainly need to do that.

Second, I think it's important for the staff to understand that from an LDC standpoint, when we're looking at evaluating the carrying costs of storage, it is not a short-term borrowing rate that we look at.

The cost of inventory is an ongoing working capital requirement that we have and is looked upon as an average balance. So, all forms of our financing are involved in that, and so instead of being a single digit financing requirement, it's more in the double-digit range for LDCs.

Regarding reserve capacity, we believe the market should determine the level of reserve capacity needed, just as it does today. Moreover, any such reserve should be committed or contracted for in a manner that's beneficial to that party responsible for the cost. There's a very strong distinction between unsubscribed capacity that the market doesn't find a use for, and capacity that's contracted for for reserve contingency purposes.

As has been described earlier, it's commonplace for LDCs to contract for capacity to meet design, peak day, and seasonal needs. When those design, peak day, or seasonal needs only occur once in 10 or more years, so what we're designing for in terms of our portfolio is looking at that probability that says what is that temperature that occurs once in 10 years or once in 20 years. That's what I'm designing my capacity levels for.

Certainly, that varies among jurisdictions and even within jurisdictions that varies from LDC to LDC within a state. But I think it's important to understand that those operational reserves do exist in the marketplace and those are the responsibilities, a consensus that's built between the LDC its state regulator and its customers in terms of what the volume of that excess capacity should be. It's also important to note that from an LDC standpoint that those reserves that exist for operational and service reliability purposes really do act to mitigate prices from the LDC standpoint.

For the NiSource LDCs, we do not contract for storage specifically to control, manage, mitigate, or influence the price volatility. Our primary purpose in contracting for storage is to meet customer reliability responsibility that we have to our firm market customers, primarily being those residential and small commercial customers.

While price volatility mitigation is an ancillary benefit of that service, we really contract for that on peak day reliability, as well as a seasonal reliability perspective.

As Mr. Oaks indicated earlier, we have a policy at the NiSource Companies where we attempt to field storage 99 percent. It doesn't matter if the summer price is at $10 and the winter price is at $5. We're going to fill storage, because there's a reliability issue. If we didn't fill storage, we're going to affect the wintertime price anyway in terms of going out in the marketplace and looking for that additional supply.

When you're looking at how LDCs use storage, it's something that we are very mindful of, making sure that it is full. Very mindful in terms of how it is managed to ensure that sufficient supply exists throughout the winter season to meet our customers needs.

I'll skip a couple of things that have probably been addressed pretty sufficiently already today. One of the things that in the staff report I think is worth noting, and that is there needs to be some care taken in the understanding on the exercise of how a storage analysis is taken care of. I've been a bit surprised today that there's only been a few comments about supply. I believe that the primary driver behind volatility today is lack of supply. If we had ample supply, we would not have the volatility we have today, and I think there's ample historical evidence of that. If we go back in and look at supply, and we look at production numbers in the U.S., we can see that when we've had excess production, volatility has been lower as well as overall prices themselves. If we look at storage, and this is kind of a high level look, if we go in and say, well, we just need more storage, we've got to think about what that does to the marketplace. An example is if we went in and added more storage. And the discussion a lot today has been well, we've got to fill storage to mitigate seasonal volatility. If you add more storage, then you add supply in the summertime, you're going to increase volatility. You're going to create incremental demand for injection into storage. It's going to compete in the marketplace if you don't add at least that much more supply. Then it's going to do no more good for you. We have to be very careful in our analysis of how we treat storage in that model.

There are a number of tools that the LDCs traditionally have used to address price volatility, one of the oldest being our budget payment plans where customers can pay a fixed monthly price for service regardless of what's going on with the volatility in the marketplace. LDCs and state commissions are also experimenting with hedging fixed-price contracting practices, as well as the marketers participating in our choice programs provide various fixed-price products to customers as an alternative to the LDC. As a general matter of fact, the LDCs are not interested, the NiSource LDCs are not interested, in contracting for additional storage. To manage what we consider to be an industry-wide problem of price volatility, we believe the costs would be prohibitive to our customers, would be disadvantageous to them, and, as is common with a state regulated LDC, those costs are recovered from those firm customers that we have.

Typically, that recovery mechanism as well has a price volatility feature to it. I don't think that we can overemphasize the value of added supply to address this issue right now. A number of parties today, speakers on the panels, have addressed infrastructure issues that may be location specific. We've seen very high volatility in the northeast. I think it's pretty commonly assumed that we need to have additional assets into the northeast.

That being the case, that's the Northeast's problem. That's not a Midwestern problem. That's not a Ohio problem. It's not an Indiana problem as far as we're concerned. Recovering added costs from our customers we believe is burdensome, particularly given the fact that it's those core market customers that today are paying the majority of the demand costs.

In conclusion, I would like just address a couple of the earlier comments. I do disagree with the comments made earlier about unbundling line pack as a means of leveling the playing field for market area storage. Line pack is a vital requirement of the LDCs to meet the temperature demand of its customers. These are complete different animals. There is no line of comparison that can be drawn between market area storage and its inherent cost versus what goes on at the market level. It is vital that we have those, and they can't provide that service to us. It's a very local service, and line pack has to be looked at as much of an art as it is a science. Those are very critical things, and I just don't think there's any comparison whatsoever there.

Relative to a question that was asked about market rates for all storage. I'm opposed to market rates for all storage. That's not to say that I am opposed to market rates for storage, because I think there are places and times where market rates for storage are very appropriate. But they are not appropriate on an across the board situation.

Finally, there was a comment about parties who hold firm capacity on the pipelines, whether it be storage or FT, there was a comparison that was drawn between our ability to buy, sell, versus contracting for a different storage service. I think I would paraphrase a popular political comment of a couple of years ago that says it's the economics my friend. If we have an asset, and have a fixed cost in that asset, how we use that asset and how we mitigate the cost of that asset is compared against those other storage alternatives, and we evaluate that asset on an economic basis. We're held to that responsibility by our commissions, and we think it's important to understand that most LDCs look at these opportunities, and these alternatives on a pure economic basis. Thank you.

MR. MOSLEY: Thank you, Mr. Anderson. We'll start the questioning with the Chairman and Commissioners.

(Pause.)

COMMISSIONER WOOD: Mr. Rizzo, I was watching on the TV from upstairs, and you all look great on TV, I should add.

(Laughter.)

COMMISSIONER WOOD: As was the last panel, I'm intrigued by the strong advocacy for the rolled in rate treatment and wondered what you thought that the existing customers would do. It's been one that in the time between when I was FERC before, and I came back. I think that clear policy on incremental versus rolled in credited with getting a lot of needed transmission built quick without a lot of push back on rate issues from existing customers and the like, and I wondered why departing from that would be such a major improvement over what we've got. Are we kind at the end of the goodwill phase of expansions being on the backs of incrementals?

MR. RIZZO: Mr. Chairman, a lot of things have changed. The success of 636, the advent of 637, the extreme segmented capacity release, forward haul, back haul. Capacity is used differently. We have a lot of new players in the market. From a pipeline perspective, secondary players utilizing the pipeline capacity, when I say secondary players, we don't have the primary contract with them. It has been released to them. They're using a form different that what was intended. The key is the pipeline capacity is being very efficiently utilized in the marketplace.

636, 637 have come full circle, have come to bear, and have increased the efficiency of the pipeline grid. What I'm beginning to see now was a little bit of the frustration in the marketplace of us being able to do the next increment of expansion and hit a number that's going to be palatable at the market. Texas Eastern and Algonquin just recently had very successful LDCs, suggesting that there is a lot of interest in the expansion of our systems. What I'm not sure of is how much of it we can do and at what price, and how we interpret what a rolled-in system benefit is is going to be very crucial to that determination. What I'm concerned about is I think the way the policy has been interpreted by some has been you can do the incremental expansion, and if it's below your system rate, you can roll it in. That's good. If the expansion cost is above your system rate, that isn't good, and that ignores all the other benefits of flexibility, reliability, and the fact that we've reduced volatility in pricing in that market. If that's the only criteria that we can have, I'm afraid a lot of the new expansion opportunities that we're going to have an opportunity to do won't occur.

What I'll say is yes. It may simplify the certificate approval process, simply because there will be a lot less certificate projects that we can bring forward.

MR. MOSLEY: Thank you.

Now, we'll go to staff.

MR. CARLSON: Greg, I'd like to actually follow up on that. How do you value the reliability and flexibility that you add to a system, and conversely how do you assess whether or you continue to incent pipelines to build only capacity that may be necessary as opposed to I just heard the last panel, no, don't go there in terms of building sort of excess capacity. What criteria would you propose that we use or add to the policy statement to take into account reliability and flexibility.

MR. RIZZO: John, first off, I'm not sure the policy statement as it's written per se needs to be changed. It's really just the interpretation of the policy statement and the concept of how to interpret what a system benefit is. The system benefit in my mind, if you expand your main line and you are relieving the price pressure for the delivered price of gas to that whole marketplace, you've provided a benefit. If you've produced volatility, you've provided the benefit. If you put more steel in the ground, you've provided a benefit to all the other firm shippers who utilize your system.

All I think we're looking for right now is clarification from the Commission that yes, those additional benefits we would have to consider. Does it have to be fully decided in the certificate proceeding, you now, today? Well, maybe. If a pipeline sponsor says I need to know now, I have to have clarity that it can, maybe it can be deferred to the next rate case, and it can be debated as long as we know that the criterion is broad enough to the extent that we can demonstrate these additional benefits, those facilities are eligible for rolled-in pricing.

MR. FOLEY: Some of the independent storage operators mentioned their projects might be more attractive if contemporaneously with their project there was some change in the zone boundary of the price they were attaching for some modification of a short haul rate, which would dovetail with their project. Is there a way to front end that idea in the certificate process or getting their proposal together in some kind of combination filing that would bring that combination idea or proposal to the Commission and have it worked out in whatever needed to be worked out?

MR. RIZZO: Rich, you're really talking about the fundamental question of rate design and cost allocation. Those are very complex proceedings. Any time you do it, no matter what, somebody likes what you do. Somebody doesn't like what you do. They like where the boundary is. They don't like where the boundary is. I'm all for encouraging additional LNG. I'm all for encouraging additional storage. I think those are great tools. I'm all for creating more infrastructure on the pipeline grid. But I don't know that you need to redefine whether a pipeline is on a zone basis or a mileage basis or redesign the zone. If you're doing that to encourage 200 a day storage input into your system some place, that's really a very small component of the overall equities across the pipeline. From that perspective, I would say those projects live within the environment of what that pricing happens to be. Anytime you change it, you're going to have relative to others winners and losers. That should not be the reason why you fundamentally change your pipeline rates.

MR. MURRELL: Greg, to the extent that you make written comments later in this proceeding and follow up what you're saying today with some additional information, I think it would be really great from our point of view in understanding the meat of what you're asking us to consider in terms of these other benefits. You've got some examples in mind, although you gave us a hypothetical in your presentation. It would be fabulous to see your version representing a real-life story, and the quantification of those benefits that you believe took place as a result of that pipeline expansion and a change at the prices at the downstream end of that basis differential and how those price impacts would have affected the people who were not customers of the expansion but got the free ride along the way.

MR. RIZZO: We will do that, I think one thing we can do this last winter as an example on the Algonquin system, we completed the hub line system which connected the Algonquin system into the Maritimes system. What that allowed this winter in New England is the Algonquin system to receive a lot of gas, somewhere in the vicinity of 150 to maybe up to 250 a day. If you look at on a narrow leasing basis into the heart of its market area, as I think everybody knows in New England, we had three very, very cold periods of time in the month of January. And each time, Algonquin was able to meet and exceed what its requirements were for the good of the whole marketplace. We had higher pressure on our G-system than we've had since I have any knowledge of Algonquin. So, it really provided for the greater good or try to address what you're asking, and tried to look at a real live example of maybe what happened on our system this winter.

MR. MOSLEY: I have a question for Mr. Anderson, following up on what you said. You said that you'd be opposed to having a general market-based rate for all storage. Yet, and I'm paraphrasing here, you said on a case-by-case basis. Could you clarify that, particularly with regard to whether or not the Commission should reconsider its market power test for storage as opposed to transportation?

MR. ANDERSON: I think there are locations. For example, in the Gulf Coast region, where storage from an LEC standpoint, it isn't really storage that's used to serve the customer, but is rather storage that is used more for price mitigation, a lot of times you're looking at a situation where during the wintertime, we would be flowing our FT full. So, we're flowing that 100 to 150 days of the wintertime, but that storage that's in the Gulf Coast might only be a 10-day storage. It might only be a 20-day storage. It's really there to mitigate price volatility. I look at that as being entirely different in its access or application for an LDC because it's not really a peak day deliverability. It's not providing balancing services. It's not providing significant seasonal resources. It's more there as an insurance policy or as a mitigation measure for part of our supply source. I look at it entirely differently in its structure.

MR. MOSLEY: Thank you.

MR. SOTO: Can I follow up on that, and you're an LDC in an area where there's no other market area storage, and an independent storage producer has proposed a project and asked us to approve market-based rates. Do you support or oppose that?

MR. ANDERSON: What is the service that they're providing? I think when you're looking at storage and how storage functions for us, it provides the peak-day reliability. It provides the balancing service. It's a no modus service. If you're looking at a new storage service like that, in my book, I don't think it's got a real opportunity to exercise market power anyway. It's the new player on the block. It's going to be something that's going to be a very, very small component of that. I would not be opposed to market-based rates on that. But, again, what is the service that it's going to be providing? Is it going to have to be with pipeline capacities to get to my city gate? Is it close enough that it will need to be delivered to me? There's a lot of variables in there that come into that decision?

MR. MOSLEY: Any more questions?

MR. HOLMES: I have a question going back to the incremental versus the rolled-in rate. Mr. Price, you were talking about previously the Commission would assess need versus having the customers come in with a contract. I can remember maybe 16 years back that the Commission based that assessment of need on 10- and even 20-year contracts or the anticipation of contracts in that range. What would you suggest that the Commission would do now that everyone says those days are long, long gone?

MR. PRICE: I'm not sure. You could really unscramble that egg and go back in time with the model we have today. The point I was trying to make is in a lot of cases, you have a very difficult time getting those long-term contracts. When you finally do get enough support, you can look at the fundamentals and probably see that the minute that you put that expansion in place, the supply may have already ramped up far beyond what the capacity of that incremental expansion can handle. But you're not quite sure that you're in a position to take the risk to overbuild for that because of our pricing mechanism. Once we've put that capacity into service, we need to offer it at 100 percent load factor rate. In the Rockies you have a dynamic that you have high consumption in the winter and a high demand to get out of the region in the summer. If I have to sell my capacity on a hundred percent load factor rate for maybe five months out of the year, I'm guaranteed underrecovery if I overbuild. The point I was trying to drive at, if we had a little more flexibility on pricing that short-term or interruptible capacity, you could develop scenarios where you could count on your own intuition of what those market fundamentals are, and perhaps build the economies of scale, build a larger project and let the market grow into it more efficiently.

MR. MOSLEY: Any more questions for the panel.

(No response.)

MR. MOSLEY: Thank you, gentlemen. We'll now move to the next session. The public forum. We have three participants who had signed up to participate in this. I would like to ask you to step up to the microphone, identify yourself. I want to start with John Forman from NiCorps. Is Mr. Forman? He's left the building. Maybe he was hungry. Next Mark Crews from MicroExchange. He had to catch a plane. Then our potential last speaker is Jim Goetz from Caledonia Storage.

VOICE: They're all together.

MR. MOSLEY: I guess their five minutes of fame is over. Fifteen minutes total. With that, I would like to close, and I'll offer an opportunity for the Chairman and Commissioners to close. As we put in the notice, I'd like to have any comments filed by November 15th. Also, for those of you who have not filed in this proceeding your presentations that would be very helpful if you would file those. Put in the record, and, of course, we encourage you to file when possible. I'd like to thank you all for bearing with us and not having any breaks. We wanted to go through this, and the panelists were hungry, turning their mikes off when their stomach growls and so forth. I'd also like to thank all of the participants, the panelists, and the audience for joining us here, and engaging us in this discussion. I'd like to thank the Commissioners and the Chairmen, the assistants, the staff, not only here but also others, who have helped us craft this storage report, and have played an active role in today's conference. I'd also like -- I guess the Chairman left. I was going to thank him for letting me sit in his seat today.

(Laughter.)

MR. MOSLEY: It feels nice here.

(Laughter.)

CLOSING REMARKS

MR. MOSLEY: With that, I'll turn it over to the Commissioners for closing remarks.

COMMISSIONER KELLY: I'd like to thank staff for kicking this off and doing the excellent job that you did on the underground storage report. I appreciate your work. I also appreciate the fact that the industry has found it quite valuable, as they've testified to today. Thank you very much.

COMMISSIONER BROWNELL: I'd also like to thank the industry, certainly the staff, for their wonderful work, as always. When we call these conferences, particularly in the world of gas, people say, oh, my God. What are you doing? Leave us alone. We're done with all that restructuring. And I think what you all pointed out today, although your conclusions may have been different is, the world has changed, and we do need to examine rules, as Joe referenced, made 20 years ago, and their applicability in today's marketplace. I also am grateful for the very forthright way in which your presentations went. We commented this morning, it is wonderful to have people come and say, here's what we want, and here's why we want it, and here is the impact as opposed to kind of dancing around these esoteric policy discussions that tell us nothing about the way you're managing your businesses. We appreciate it. We might put you up as poster children for some other members of the energy sector who need to learn that kind of direct here's what we need to do. Thank you.

COMMISSIONER KELLY: I know that it takes a lot of time and effort to devise these presentations, come here, and give them, and I want you to know that it is very, very beneficial to us. You've piqued our thinking. We'll be back together again soon to talk about these issues in some more depth. Thanks very much.

MR. MOSLEY: Thank you all. With that the meeting is over.

(Whereupon, at 3:05 p.m., the meeting concluded.)