BEFORE THE
ILLINOIS COMMERCE COMMISSION

GAS AND ELECTRIC POLICY SESSION
2014-2015 WINTER PREPAREDNESS

Wednesday, October 22, 2014

Springfield, Illinois

Met, pursuant to notice, at 1:30 P.M., at 527 East Capitol Avenue, Springfield, Illinois.

PRESENT:

Douglas P. Scott, Chairman

John T. Colgan, Commissioner

Ann McCabe, Commissioner

Sherina E. Maye, Commissioner

Miguel del Valle, Commissioner

MIDWEST LITIGATION SERVICES, by
Robin A. Enstrom, RPR, CSR
CSR No. 084-002046

PROCEEDINGS

CHAIRMAN SCOTT: I'm told everything is ready in Springfield.

COMMISSIONER COLGAN: We're in Springfield.

CHAIRMAN SCOTT: Or excuse me. In Chicago. One of those weeks, you know.

COMMISSIONER DEL VALLE: It's all that flying.

CHAIRMAN SCOTT: That's right.

Like to welcome everyone and convene the Illinois Commerce Commission Gas and Electric Policy Session, the 2014-2015 Winter Preparedness Meeting.

With me here in Springfield are Commissioner Colgan, Commissioner McCabe, Commissioner del Valle, and Commissioner Maye. I'm Chairman Scott.

As you know, we do the winter preparedness meeting every year. This year I think it takes on a little more significance given the events of last winter and trying to make sure that -- that we're prepared for a winter hopefully not as bad as we had last year, but obviously the conditions that we had last year -- and we saw the price spikes and everything else -- makes this meeting that much more important.

So we appreciate everybody coming and giving their testimony to us today. I'm going to turn it over to Commissioner Colgan and also thank him and Linda Wagner for the great work in putting all of this together. We really appreciate it and look forward to a good meeting.

Commissioner.

COMMISSIONER COLGAN: Thank you, Chairman, and I echo your thanks to -- especially to Linda Wagner for the work that she's done in helping put this together. It's been a lot of work, and I think we've got a good lineup for you today.

As we're all aware, as the Chairman just mentioned, the winter of 2014 was characterized by historically cold weather, record high natural gas and electric demand, and in some areas of the country, very high natural gas prices which translated into abnormally high electric prices. The cold weather tested the performance of the natural gas and electricity systems and the functioning of markets which at times came under extreme stress.

Shortly the winter months of 2014-15 will be upon us, and while we can hope for more moderate weather, we need to be prepared for similar conditions.

And, by the way, welcome to central Illinois, and isn't it a nice day out there today. Thank you all for being in here while we could be out there.

As a result of all of this, we have designed this Gas and Electricity Policy Session to explore the many issues surrounding the 2014-2015 winter preparedness. We're privileged today to have a group of national, regional, and state experts on this topic who will share their thoughts and experiences with us. Included are representatives of RBN Energy; the American Gas Association; the Midcontinent Independent System Operator, MISO; PJM Interconnection; and the four Illinois local distribution companies: Ameren, Nicor, Peoples Gas/North Shore, and MidAmerican.

The Commission has asked these

panelists to address questions such as how is the U.S. natural gas market positioned to meet the 2014-2015 winter demand?

Have the appropriate adjustments been made in the coordination between gas and electricity markets to avoid some of the problems we experienced last winter?

What challenges are the RTOs facing with respect to assuring electricity reliability during the 2014-2015 winter months, and how are they addressing those challenges?

Have the LDCs, the local distribution companies, been able to refill gas storage facilities or otherwise assure access to supply for the 2014-2015 winter months?

Given the transmission pipeline operating restrictions the utilities experienced during the 2014 winter months, how have the pipelines addressed those operating issues?

And I'm sure we're all looking forward today to hearing our panelists address these issues.

Today's Policy Session includes three panels.  The panels will address issues regarding the upcoming winter from a national perspective, then from the RTO perspective, and from the Illinois distribution company perspective, respectively.

Our first panel will address the national perspective, and we have two panelists for that, and if they would come forward -- Rick Smead from RBN, and Brendan O'Brien, who is from the American Gas Association. And I'll just briefly introduce both of you, and then I'll turn it over to you, Rick.

Rick is the managing director of Advisory Services for RBN Energy, an analytics and consulting firm based in the fundamentals of natural gas and natural gas liquids industries. He specializes primarily in the natural gas sector, offering expert policy analysis and advice, litigation support, and strategic advice with respect to gas pipelines, potential supplies, and market initiatives.

His background includes over nine years as a director with Navigant Consulting and over three decades in the natural gas industry. That experience included over 20 years in senior management of major interstate pipeline systems. His consulting practice has spanned the domestic natural gas industry, all aspects of the shale gas boom, liquefied natural gas trade, and consumption opportunities.

He was a pioneer in understanding the shale boom, managing and coauthoring the first major quantification of the U.S. shale potential in 2008, the pivotal North American Natural Gas Supply Assessment.

Most recently, he's been deeply involved in the opportunities for the use of natural gas abundance, including power generation, LNG exports, and gas-to-liquid technology.

He holds a bachelor of science in mechanical engineering from the University of Maryland and a law degree from George Washington University.

Mr. Smead, we look forward to your comments.

MR. SMEAD:  Thank you, Commissioner.

Well, that's a complicated background.  I'm going to try to keep this real simple.

Brendan and I are going to try to establish the -- sort of the background against which this winter will be occurring at the national level and, in my case in particular, in terms of just how does supply stack up this year versus last year and what's been happening.

You know, first, in this region, the thing that I've always noticed about Illinois and this part of the Midwest is you got a lot of pipes, got a tremendously complex network. But the most important aspect of it, you got the old Legacy pipes, Natural Gas Pipeline Company, Panhandle Eastern, Northern Natural coming up from the southwest. Got ANR coming up from the southwest and the Gulf Coast. Midwestern, Texas Eastern, and Texas Gas from the Gulf Coast. Trunkline from the Gulf Coast. All these pipelines from Canada: Great Lakes, Viking, Northern Border, Alliance. And then the interaction with the storage at Dawn and Michigan. So a tremendously robust interaction with the Canadian market. So, basically, you're served from every possible direction.

More recently, they built Rockies Express to bring Rockies gas straight into the region, but the region it was going to didn't actually need it. So Rockies Express goes both ways and is starting up its first backhaul this year -- just 200 million cubic feet a day; ultimately they're moving to 1.4 Bcf a day -- moving Northeastern gas back into the Midwest, primarily into Chicago.

Similarly, ANR has its Lebanon project. Longer term, couple of really big pipelines, Nexus and Rover, have been proposed to go up into the Dawn area, but they're not this winter.

But the bottom line is that the supply abundance in the Northeast is showing really major benefits in this region because of its ability both to get back here physically or just to free up gas that's coming from other sources.

So what's been happening with that supply? Last year the production in the Northeast -- meaning basically Pennsylvania, Ohio, and West Virginia -- ramped up until it got to about 15 Bcf a day by March. And, of course, it spiked a bit in January, dropped a bit in February -- or late January and February with some freeze-offs. This year it's a lot more.

These are numbers from Bentek -- the forecasts are. They've got it flattening out, but every indication is it's not actually flattening out; it's following the same trend. Northeast production appears to be running about a total of 4 Bcf a day more than it was last year. That is the equivalent of 400 Bcf of storage inventory, and these fields are all in the same place as the Northeastern storage fields, meaning basically this production supplants what the storage relied upon for last year to the extent of about 4 Bcf a day, and it can get back here. So it's a very, very healthy situation.

The challenges of getting it to some of the Northeastern markets are still there. Pipe has not been expanded to the extent it needs to be, but the middle of the country should be isolated from that.

Meanwhile, these estimates of

Northeastern production keep jumping. Bentek last year said that by 2018 be up to about 18 Bcf a day. This year they say it will be up around 26 a day. Between the two years is actually an increase of 7 Bcf a day in their estimate by the time they get out to 2019. So that's the sort of step function that's occurring every year as the efficiency of development in the Marcellus shale and Utica shale are just yielding deliverabilities nobody ever thought could happen.

So the implications of this production growth:

First, with the REX reversal, the Northeast is feeding Illinois directly.

Second, the fields are in the same place as the storage fields; so production replaces storage deliverability.

When the Northeast is oversupplied, it significantly reduces the stress on other supplies to the combined market.

Last winter a lot of stress was put on Canadian supplies which was one of the things that pulled prices up in the Chicago area. This relieves all that. We're exporting to Canada now from the Northeast. So it's a real benefit.

So bottom line is gas service in Illinois should be very secure as a result of the national backdrop against which it's working, which doesn't relieve us of having to resolve the various mechanical issues that are addressed in the inquiry here, and we'll be happy to talk about those, but it's -- every reason to believe or to expect to be very optimistic.

I do direct everybody to our free blog that we do at RBN where we tell you all about this until you're sick of hearing it, and the price is right.

And with that, I will turn it over to Brendan.

COMMISSIONER COLGAN: Next we have Brendan O'Brien. Brendan is an energy analyst at the American Gas Association located in Washington, D.C. He's been at AGA for the last two years working on natural gas distribution company core market analytics and industry financial benchmark studies. Brendan also manages a national scale macroeconomic modeling platform for evaluating energy-related policy topics.

Prior to joining AGA, he worked as a contractor at the Department of Energy providing data analysis for offices such as the Energy Information Agency and the Office of Weatherization and Intergovernmental Program.

Brendan holds a B.S. in industrial engineering from Purdue University.

Brendan, the floor is yours.

MR. O'BRIEN: Thanks for having me here today.

I'm going to talk a little bit about not only our expectations for this winter but also how we saw the performance on the national level for the natural gas industry and specifically LDCs this past winter.

First off, I kind of want to stress our outlook for this upcoming winter, particularly how prices will look for the average consumer because, as we all know, winter is coming.

So demand: We expect for the actual consumption to be much more like a normal winter, perhaps not, of course, like last winter but the winter before.

In addition, something that we've always noticed is that -- thinking about not last winter but the winter before -- that homeowners are continually expected to conserve more, and certainly a long, ongoing trend of energy efficiency will continue so that is part of our analysis.

We also think that the commodity price will probably increase a little bit compared to the year before with only a small increase to the fixed delivery cost. This comes from an AGA survey that looks at year-to-year bills, and we just see a small change in what that was from the previous year.

So putting this all together, the fact that we don't expect the same severe winter temperatures that we saw last year and with the slightly higher gas costs, we expect the price for the average consumer to be pretty much not dramatically different than it was in the previous years. So nothing out of the ordinary.

So thinking about how last winter

will affect this winter, storage -- a very important factor for everyone to think about -- reached an all-time low of withdrawals of over 3 Tcf at its lowest point sometime in the middle of the winter.

Now, since then, we've actually noticed that it's been increasing almost triple digits for many, many weeks, and so going into this winter we expect to be at the same point that we were in the previous winter, completely reclaiming all losses that had taken place with the increased temperatures -- or sorry -- decreased temperatures that took place.

Going along with that, last year we certainly saw increased production from the year before. This year we see another 3 or 4 Bcf per day of production nationwide and that, of course, throws in other -- a couple hundred Bcf of storage equivalent. That -- again, this was something that helped last year with the cold winter, and this year we have an even higher margin to work from.

And to further reiterate, this is a graph showing how much the plays with shale gas has actually increased -- most notably Marcellus, Eagle Ford, and then the Utica where you have gas actually coming from a much closer region like Ohio.

So going along with that, there certainly are going to be potential increases in demand in the future. Nothing here should be too surprising. Some of these aren't necessarily in concrete. Of course, we don't know how LNG exports will work out in the future, but in hand-in-hand with this increase in production, certainly demand will help grow that because there will be further need for pipelines and continued production.

So this graph right here shows more or less what the last couple years of prices have been on the Henry Hub. This fits more or less with what our expectations going out well into 2020s as far as the 4 to $6 range. The one spike noted took place during this winter, but relative to what the price range was in the earlier half of the last decade, we don't have the same price swings that took place before.

And so when also talking about this

current winter and how we might see the prices of the commodity gas going up a little bit, that's relative to prices in 2013 and 2012, which are significantly lower than what the long-term trend has been.

So looking towards the future: Growth in natural gas infrastructure -- talking production, transportation, storage, distribution -- these are all how we've gotten to where we are today -- by growing these assets. Well-planned, critical infrastructure development is certainly a key to our future. We definitely see this as a continuing trend in the long run.

Demand signals, among many factors, have certainly facilitated real growth, not just more wells being put into play. Certainly there's a need for those wells.

Regulatory principles and precepts evolve. The future of the natural gas industry may include new regulatory challenges, but the iterative process of industry opportunity and regulatory responsibility certainly help to serve all classes of customers.

The future of natural gas is a strong

and bright future with efficiency of production, transportation, and, of course, direct use at its core.

I guess at that point I'd like to open up for questions, and for anyone who wants to contact me, here is my personal information.

COMMISSIONER COLGAN: Okay. Thank you, Brendan.

Questions?

CHAIRMAN SCOTT: Sure. So going back to the theory about the winter not being necessarily as bad, since weather is more -- is localized and last year we kind of had it where we got hit bad in several parts of the country at the same time -- does that have to happen to mess things up? I mean, if -- say, what if the Northeast gets hit with another hard winter, even if we don't have the same thing here, what does that do to the -- to the outlook?

MR. SMEAD: Well, as you'd expect, Mr. Chairman, the -- if another region is having very severe conditions but you've still got a fair amount of flexibility here, then you wouldn't see any effect.

It would be -- it would be similar to what the Northeast saw last winter where, on the day that the gas price hit $120 in New York City, 275 miles away it was $4.30. And so basically it depends on where the constraints happen because of volatility of weather.

CHAIRMAN SCOTT: Okay. And, second, the -- we're seeing all the trends now for more natural gas being used for electricity generation directly. I'm assuming there's not a lot of impact from that yet, but is that -- is that a fair statement? But obviously it's something we expect to happen more as time goes on? For either of you or both of you.

MR. SMEAD: Yeah. There is a fair amount -- or I guess one of the things that happened last winter was that, for the first time, gas-fire generation was running in the winter, as you know, and wasn't set up to run in the winter. They did not have firm commitments on pipelines to the extent that they would have if it had been designed to run in the winter. So we're starting to see that from existing facilities.

The actual coal retirements have not really been happening yet; and, of course, a number of them are being argued about in some of the regions as to, after last winter, whether they should happen yet, but -- but we're seeing some effect.

We've seen a significant increase in gas-fired generation. The biggest increase that we've seen, though, historically was in 2012 in the summer when prices went into the basement because of a very mild winter and gas-fired generation swung up about 6 Bcf a day, and then it swung right back down as soon as prices recovered. So, in a sense, that was a pretty good stress test of the system.

So, yeah, we're starting to see it.

CHAIRMAN SCOTT: Mr. O'Brien, did you have anything you want --

MR. O'BRIEN: No, I don't have anything to add to that.

CHAIRMAN SCOTT: Last, exports. Now we're starting to -- we've seen a couple places get approval to do that. Is that -- does that have any impact on us here?

MR. O'BRIEN: I mean, there is no real consensus of how much that export will look like. But, I mean, we certainly don't think that it will have any serious, significant impact on consumer prices.

MR. SMEAD: Yeah. Yeah. It's -- basically, something around 10 or 12 Bcf a day looks like an upper limit on what the world will absorb, and at that level that's way within the ability of the production industry to swing up or down without any change in prices. So it should not have an effect on prices.

And, in fact, we -- the industry -- because of this huge surge in Northeast production, the industry really needs the exports.

COURT REPORTER: I'm sorry.

MR. SMEAD: Sorry. The industry really needs the exports. Excuse me. Yes, I choke up when I talk about exports.

CHAIRMAN SCOTT: I guess. We can get you a tissue or something.

The industry needs the exports because?

MR. SMEAD: To balance the market.

CHAIRMAN SCOTT: To balance the market. Okay.

MR. SMEAD: Yeah. Yeah.

CHAIRMAN SCOTT: Thanks. Thanks.

COMMISSIONER COLGAN: I had a question along that same line. With the increased production -- and it seems like it's a significant increase -- where does all the gas go? Is it -- is LNG the route that that is all going to go to, or are you looking at other markets for it in addition to LNG?

MR. SMEAD: There's also a lot of expansion in the petrochemical industry along the Gulf Coast. We expect -- at RBN we expect the Gulf Coast to really be the epicenter of demand with Henry Hub, which used to be the epicenter of supply, being where it's all going; and the exports, petrochemical, steel, and otherwise, we look oversupplied for a while.

COMMISSIONER COLGAN: Mr. O'Brien, you talked a little bit about how you were going to expect -- we could expect prices for consumers to go up slightly. Can you go into that a little bit in terms of why you think -- with such a high supply, why the are prices going to go up?

MR. O'BRIEN: Well, to reiterate, when I showed the chart of recent prices -- at least the Henry Hub prices -- we have been at a relatively lower price point for the commodity cost of the gas.

And so looking at this next winter, we do see that the price will be a little bit more what you'd expect in the long run. So that certainly has a factor on it.

And then when you're thinking of winters like the last one, you certainly had a very high usage per customer. So we're coming down from that.

So the combination of the two sort of balances out to being about, you know, the same as what we've had the past. Actually, I think EIA has revised their outlook and are now showing pretty much the same thing or even maybe a few percentage points lower.

COMMISSIONER COLGAN: How much reliability can we put on that we're going to have a more moderate winter? I don't recall last year predictions that we were going to have a polar vortex. You know, what's the -- I guess there's no way to really project that with any sort of absolute certainty, but what are the models that are being used for that?

MR. O'BRIEN: I mean, we've been tracking what the NOAA climate center has been proposing, and so far they've been sticking to, I think, somewhere around 367 heating degree days nationally at least, and compared to last year, that's over 420 -- or 4,020 -- or 200 heating degree days. And so that -- that 360 -- or sorry -- 3,600 is more or less what we've seen in years past. And so they really haven't revised that much, and I think EIA has also proposed very similar numbers as well.

COMMISSIONER COLGAN: Last --

MR. SMEAD: In Houston, my wife said we couldn't buy a pool heater. So we're hoping it stays warm.

COMMISSIONER COLGAN: Last year we heard a lot of discussion about the coordination between the electricity markets and the gas markets. And I know NAESB has done a lot of work in this space to try to figure out where we need to be headed. Can someone -- and, Mr. Smead, can you bring us up to date in terms of that process and where things sit from your perspective?

MR. SMEAD: Sure. The issues that NAESB took on all had to do with the nomination timeline and the timing of the gas day, when would it start.

You know, historically the gas day starts at 9:00 A.M. central time, which is way after the time that power generators need to be able to change their nominations.

And so the FERC started this process by first issuing a proposed rulemaking that would make -- that would change the time to 4:00 A.M., and then saying, "Okay, Industry. Go work out a consensus standard."

We had a lot of meetings at NAESB, and all had a frank exchange of views, and ultimately there was not agreement on the timing of the gas day. There have been standards being developed now through NAESB for all of the other pieces, for the timing of the intraday nominations and the sort of notice periods. A lot of things to smooth the way.

But right now the timing of the gas day stills remains largely unresolved but with the understanding that both sides can probably find a middle ground to make it work.

What that means for this winter: In practical terms, I usually hear that it really doesn't matter that much if you've got a little bit of flexibility in the system. In essence, the pipelines can juggle and make things work. But it's when it gets as strained as it did last year that it matters a lot.

And so progress is being made. FERC has made it pretty clear that, if the industry doesn't resolve the issue, they're willing to, and that scares enough people that I think something will happen at some point.

COMMISSIONER COLGAN: Yeah. Yesterday I was at the OMS annual meeting over in Carmel, Indiana, and I asked John Bear of MISO a similar question. And I think an accurate summary of his response was he thinks process has been made, but there's a lot more that needs to be made.

MR. SMEAD: Yes.

COMMISSIONER COLGAN: So would that be a similar assessment that you have?

MR. SMEAD: Exactly. Exactly. And a lot of work did go into it, but it's just difficult issues and -- and it was -- it was frankly made somewhat difficult for the gas industry in that the FERC basically put out a rulemaking that said "We hereby propose that the electric industry win. Why don't you guys go negotiate." And so that was how it got characterized for a while; but, honestly, everybody -- everybody really worked on -- and pretty honestly with each other to try to find the right answer, and I think we're -- I think we're close.

COMMISSIONER COLGAN: So if we have a winter that comes up and if the predictions are it's going to be a more moderate winter, we can expect that there won't be the kind of problems that we anticipated last year. If we did have another, you know, incident like we had last year, would we be under similar stress, or do you think we're -- we've mitigated that somewhat?

MR. SMEAD: It's -- it's mitigated by the little bit of additional pipeline capacity, by the massive addition of supply capability, and -- and in some -- in a lot of ways, especially in the power markets, everybody learned a lot last winter. So the operational expertise on both the gas and electric sides was significantly enhanced because people were dealing with situations they'd never seen before.

COMMISSIONER COLGAN: Adversity is a great teacher.

MR. SMEAD: Yeah.

COMMISSIONER COLGAN: Did you have something to add?

MR. O'BRIEN: Yeah, actually. So every year AGA surveys our membership to try to get an idea of how they reacted during the winter heating season.

And one of the questions we had in this past winter, being a particularly serious winter, was in regards to did you have to do anything special or out of the ordinary in order to handle your demand.

And the response was around 85, 90

percent of the utilities said that their resource plans were more than adequate to be able to react to whatever challenges they faced over the winter.

And then for those who replied that there might have been something different, their replies were more along the lines of we maybe had to go and purchase gas on the daily market. It wasn't anything out of the ordinary or anything, certainly, dramatic.

MR. SMEAD: Yeah. That's a useful comment because the -- we -- the electric industry got so much focus and its interaction with the gas industry. But the gas LDC business -- with their -- with firm contracts, with storage, and with their resource planning -- were just dealing with the designed condition that they designed for, and it was very straightforward.

COMMISSIONER MAYE: Commissioner Colgan, may I ask a question?

COMMISSIONER COLGAN: Certainly.

COMMISSIONER MAYE: Thank you both for coming all the way to wonderful and warm

Springfield.

But I wanted to ask -- maybe this question might be better directed toward Brendan. So I know, just in speaking to colleagues across the nation, and I think a concern or, you know, something that has been mentioned a lot was that a lot of the gas utilities need to probably look at their procurement policies and, you know, in trying to think about what happened last winter but also in preparing for the next one. Is that something that you all discuss at AGA and your members -- you know, trying to determine whether or not they actually had enough in the first place?

I mean, there was obviously a lot that went wrong, and while we weren't necessarily expecting what happened last winter, I think across the board a lot of people think we could have been better prepared anyway. So is that something that has come up at all at AGA -- procurement policies?

MR. O'BRIEN: Not something that's, certainly, a wide stroke across the country. I can't speak to any specific scenarios where that might have been an issue.

We actually did release a special report this year that is talking about this past winter and how we saw LDCs respond to it. I've actually made it available for you guys for afterwards to take a look at, but --

COMMISSIONER MAYE: Can I ask another question?

So I know that this is not something that is imminent. Obviously, we have not -- with 111(d), they have proposed regulations, but we don't know. I mean, let's say there will be, you know, a carbon rule put in effect over the next couple years. With the reduction, if there is, of coal plants -- with the retirement, rather, of -- and that's what will happen if this rule actually does go into effect. How will that necessarily have an effect on future winters coming, in particular to the -- as it relates to the gas industry and what happened last winter and what may happen in the next couple?

MR. SMEAD: Commissioner, it all depends on what you design for. If the gas-fired generation fleet is designed to run at a baseload to really replace the way coal runs now, then the economics of firm pipeline transportation work out because you're spreading it over a much bigger volume. You can have the full reliability year-round and do things that can't really be economically done right now by a lot of generators.

So, in essence, a gas fleet that is designed to run like a coal fleet can be absolutely as reliable and as cost effective. The challenge we've had has been that there are other things that gas generation -- only gas generation can do in terms of swinging up and down to make up for intermittent renewables and that sort of thing. And it's when it's filling that role that a lot of these issues get really complicated.

But the coal replacement -- as long as the system is designed to run properly in the coal replacement scenario, there should be no issues at all, and we have more than enough supply to serve it.

COMMISSIONER MAYE: That's good to know. Thank you.

COMMISSIONER COLGAN: Chairman Scott.

CHAIRMAN SCOTT: Just a follow-up on that. So that applies to both the ramp-up to 70 percent that's in building block two of 111(d) regs, but also the anticipated kind of new gas that's going to end up getting built. Because one of the contentions is that the interim targets, the 2020 targets, kind of force the hand of a lot of new gas because that's one thing that people can do that quickly to make that kind of an impact.

MR. SMEAD: Yes.

CHAIRMAN SCOTT: So your answer is the same concerning both?

MR. SMEAD: Yes. Yes. That if -- really, if gas -- if gas just continued on the -- if the gas and coal market shares of generation just continued on the path they've been on since 1990 with no EPA overlay, they would intersect in 2028and be running at about a 60 percent capacity factor.

So it's way within the operating envelope for the existing generators to move up into the 70 percent range if they have -- if they have sufficient pipeline capacity, and then new generation layers will come in after that.

It is very important that each new facility be designed, including the system that serves it, as a total system.

COMMISSIONER COLGAN: Any more questions?

Thank you, gentlemen.

CHAIRMAN SCOTT: Thank you.

MR. SMEAD: Thank you.

COMMISSIONER COLGAN: Our next panel will be giving us the regional transmission organization perspective, and we have Mike Kormos from PJM Interconnection and Melissa Seymour from MISO.

Michael, we'll kick this off with you. Michael is the executive vice president of operations at PJM Interconnection, and he's responsible for all services that touch reliability, including system operations, system planning, information and technology services, security, and regional coordination.

Previously, Mr. Kormos was the vice president of system operations and has served in various management and engineering positions in the operations division. He was responsible for the oversight of the day-to-day operations of implementation of locational marginal pricing and the new market structure.

Formerly, he was a member of the operating committee of the North American Electric Reliability Corporation, NERC, and currently sits on the board of directors of the ReliabilityFirst Corporation, the executive committee of the Eastern Interconnection Planning Collaborative, and the Industry Leaders Council for the Consortium of Electric Reliability Technology Solutions.

Mr. Kormos earned a bachelor of science in electrical engineering from Drexel University and a master's of business administration from Villanova University.

Mr. Kormos, welcome.

MR. KORMOS: Thank you, and thank you for having me.

And I will try to go through real quick what we're looking for as far as this coming winter and some of the steps we are taking and continue to take to be better prepared from the lessons we learned last winter and then even touch a little bit on where we'll continue to go even after this. We're not going to necessarily just stop at the stuff we can get done this year.

So, first off, just for our projections for this coming winter.

Looking at our load right now, what we call an unrestricted load forecast, a 50/50 load forecast, we're looking at about 133,500 megawatts for our peak load. The 50/50 is basically there's an equal probability we'll come in higher than that if the weather is colder than average, 50 percent chance we'll come in lower than that if the winter is more mild than normal. It also has no demand response at this point taken out of that load.

You'll see on the capacity we are summer peaking. So we are going into the winter with 183,000 megawatts of capacity. While you would look -- on paper we look like we have a great reserve margin there, we had pretty much similar margins last year as well, and we know some of the challenges we had in last winter.

The mix of our generation hasn't really significantly changed the last year. We're pretty much going in with the same mix we had last year as far as coal to gas. Right now we have about 12,000 megawatts of coal scheduled to retire, but it will not retire until after this winter. It is scheduled to retire in the April time frame of next year. So we're pretty much going in with -- and more -- mostly a slight increase in some of our gas productions. We do have a couple new units coming online. Other than that, our mix is pretty much as we saw last year.

Some of the upgrades that we have undertaken on the transmission side:

This is the ComEd footprint, our part of Illinois. We put in new SVCs, static VAR compensators, reactive devices that are able to support the voltage, gives us dynamic control for voltage. We have a fairly large one at Prospect Heights substation.

We also put some transformers in at the Waukegan and Plano substations. A number of lines you'll see on that map out west where the wind is, as well as into the Chicago area, have been reconductored to increase their ratings as well, and we do have a new generator coming online. The Nelson Energy Center is scheduled to start production early this winter. We expect at least half that output, about 300 megawatts, to be available this winter; hopefully maybe getting even the other half sometime during the winter. It's all expected to be online prior to next summer.

This is just the rest of PJM. Again, similar upgrades. A lot of SVCs, static VAR compensators. They're the little sort of turquoise dots you see at many different substations that allow us to better control our voltages.

We do have some generators in this part of the footprint. They are the blue circles. They are generation that is retiring or has retired since last winter, but we also have two new units coming on: The Crown Point unit, which is all the way in New Jersey -- it's a 600-megawatt combined cycle -- as well as a larger generation in -- it's not on the map.

It's actually in northwest Virginia called Warren County. That's actually a 1,300-megawatt combined-cycle plant as well. So there are increased gas supplies. And, again, similar thing here: A lot of reconductoring that has been put in place to upgrade the transmission system going forward.

We, as part of our winter preparedness, run base case winter studies. These are the conditions we looked at. You can see we used a little higher than average load in our model mainly because we put -- that -- that load forecast is based on the systems in our footprint not all peaking at the same time; typically, the weather is diverse enough.

In this case, we actually have all our subsystems peak at the same time. That's why we have a little bit of a higher load. We are looking at about a 4,000-megawatt import into PJM, predominantly from MISO where we do have some units that are our capacity resources. We used a 183,000. And in this case, we took out 23,000 megawatts of generation. That is more than our average but not necessarily what we saw last winter, but we'll talk about that in a minute.

In this case, we actually -- we see no problems. Some of the issues we see can be easily mitigated with either switching procedures or off cost, running generation out of merit order --- what we would see and what we've normally seen during previous winters. This is not necessarily unexpected.

In addition, though, to that base case, we are going to stress the system based on what we saw last winter. So in this case, we're running what we call now a 90/10 load forecast, which is there's only a 10 percent probability we would expect to get a higher load than this. This is at 142,550. That is pretty much the load -- little higher than we saw last year. It basically was a 90/10 event we saw last year.

We have also put in higher outages. In this case, 41,000 megawatts of outages. That is very similar to what we saw last year.

And this year we're also going to run some pipeline contingencies. One of our concerns is the fact that we know we have, in some cases, significant generation running off individual pipelines. But if we were to lose that pipeline, if it would suffer a catastrophic failure, how would that impact our ability on the electric side? Those studies are being run. We expect to have them finalized very shortly. They'll be out for the public; and, again, we'll be happy to provide those to the Commission when they're done to identify if there are any new issues.

So a couple things coming -- the recommendations that we've been working on since last year. I'll try to go through these real quickly.

The first one is winter resource capability testing and preparation checklist. So we've done -- gone through with all our generators a winter checklist to make sure they are doing the winterization. A lot of this comes out of NERC and some of the experiences they've had at other places. All our generation have gone through that and are signing off that they have gone through that process.

We are also offering this year the ability for a generator that did not run most likely since last summer -- or, in some cases, since last winter -- the opportunity to come on and test themselves prior to the winter. While we saw a lot of weather-related outages last January, we also saw some just normal outages where units that had not run or had not run on their secondary fuel literally in months -- in some cases, years -- when they tried to start up, they had non-weather-related issues. A mouse can chew through control wiring and things of that nature. One of the things we want to do --

COMMISSIONER MCCABE: How does -- how does the test you're doing this year and the checklist compare to what you did last year?

MR. KORMOS: We didn't do either last year. That's the thing.

So, hopefully, now they'll have the opportunity, if the unit hasn't run, to bring the unit on and get the bugs out. So, hopefully, if there is an issue that they did not realize, we'll find it early in December, and then they'll be better prepared to then come on. It's not necessarily going to help the very cold weather-related issues. It's tough to test for those if we don't have those conditions.

The next one: A lot of it -- and there's a couple of these. A lot of the issues last year came in scheduling and the coordination with the gas thing. Now, interestingly enough, it was not a physical issue with us and the gas system. From a reliability perspective, the coordination we had with the pipelines last year was excellent. I don't think either of us were surprised. We understood what units could run. They understood what units we were going to run. I don't think they had any pressure problems that we've seen in previous years where we didn't have that coordination. For us, a lot of it came down -- our biggest issue was commercial terms and the scheduling issues. You know, there's the idea that we don't have firm transmission. We ran 30,000 megawatts of gas last year, and it was all on firm transmission on the gas side. Almost every one of our pipelines had an OFO against it during that period of time.

The issue for us, though, was some of the commercial terms on the commodity side that generators were dealing with with ratable takes, weekend packages, the price. I think everybody knows what happened on the price side of it. That made scheduling units very difficult for us, and the fact that, in some cases, we were trying to make decisions on a Friday for a Tuesday because of the Martin Luther King holiday and the way the gas was being packaged to the generators at that time.

We've done a lot of work to try to get more clarity, better modeling. Ultimately, so if we need to make those decisions again this winter, we can, but we'll hopefully make them smarter, wiser than we did previously to minimize any financial impact to it. I won't sit here and tell you that we've solved that problem. That problem still exists. Ratable take is still out there. The price can still go to $100 on us. There are things that at this point we're really not going to be in any position to control. A lot of that has do with uplift.

One of the things we are looking at is our cost-based and price-based offers. One of the things we are trying to push through is the ability for generators to at least change their cost. So one of the things we saw last year was, because of the volatility on the commodity side of the gas, the prices were changing during the day, and generators that had estimated their costs were no longer able to procure the fuel at that cost and were making themselves unavailable. They couldn't afford to run at a loss. We're putting steps in place where they'll be able to update those costs. So we'll be able to at least get the generator, if they can, at least understanding what that price impact may be.

We continue to do a lot of data sharing and coordination with the gas industry. As I said, I think from a reliability perspective, we made real significant gains last year. We're continuing to work with them going forward. We're also doing a lot of other -- just improvements both with our neighbors on the -- mostly that was with our southern neighbor, and I think us and MISO -- I think we -- we're very comfortable we came through last winter very well. Our issues were probably more to us to the south at this point.

COMMISSIONER COLGAN: Would you agree

with the assessment that there's been progress made, but there's a lot more work to do in the coordination?

MR. KORMOS: Absolutely. Absolutely.

COMMISSIONER COLGAN: Okay.

MR. KORMOS: Here's another couple slides: just the studies, the training, the drills we do. One of the things we are doing is a generation outage survey. We're going out to actually find out what the inventories are, what the gas commitments are, what their gas contracts are, with all of our generators, to have a much better handle. Last year I think that was one of the other lessons we learned -- is we were trying to manage who could get gas, who couldn't get gas, who had dual fuel, who had maybe fuel issues where we had truck drivers who ran out of times on their CDL and couldn't make deliveries. We had probably every issue you can imagine. Trying to get a better handle. It's all going to be in a database this year. It's all going to be automatically updated as we contract that so, again, we're better prepared.

You also see the meetings we have

with obviously all our neighbors as well as ReliabilityFirst, and then I said the gas-electric coordination. We've had a number of meetings -- and, actually, we have a meeting tomorrow at our site with all of our major pipelines to talk about winter preparedness and just making sure we all understand how we're going into the winter.

My last thing is, again, as I said, we're not necessarily going to stop. We'll continue going on in PJM dealing with this issue. In some cases, as I think the previous speaker said, if we go in a normal winter, we're obviously not expecting major price impacts or reliability impacts. But I think last winter gave us a glimpse into what the future could be as we become more dependent on gas. So even if we get through this winter, we still think we need to make improvements. You'll see a couple of things we're doing regarding how we do our drills based on it.

We have a very big effort going through -- I think most people know -- which is what we call the Capacity Performance Product.

One of the things we recognize is we need to tell the gas industry what we need. We understand there is probably a need for infrastructure. There will be a cost associated with that, but at the same time we need the products that we need. We need the services we need. We are not an LDC. Our generation cannot operate like an LDC. And so maybe while some of these contractual terms work for an LDC who have large storage, long -- you know, large draws every day, for generation, it does run intermittently, and we need that flexibility. Obviously, at this point some of that needs to be done. But what we feel we best can do is basically say what we're willing to pay for and hopefully have the gas industry respond and being able to provide those services to us.

It already was talked about the harmonization of the gas and electric day with the FERC order. We'll wait for that rulemaking. We have very publicly stated we are willing to move our market. That is not an issue for us. We'll move it to where -- ultimately wherever people believe it makes sense to have that coordination be better managed.

And with that --

COMMISSIONER COLGAN: Do you hear a similar sort of flexibility on the gas side?

MR. KORMOS: No.

COMMISSIONER COLGAN: No. Okay.

All right. Well, next --

Any questions for Mr. Kormos before we go?

CHAIRMAN SCOTT: One quick question.

COMMISSIONER COLGAN: All right. One quick question.

CHAIRMAN SCOTT: I noticed in your one chart you didn't anticipate any demand response being out of there. Does the 745 play into this at all?

MR. KORMOS: Plays into it a lot.

CHAIRMAN SCOTT: Maybe it wasn't a quick question. Sorry.

MR. KORMOS: I mean, yeah, there's a lot of uncertainty now. Our demand response has typically been a summer product anyway. We asked for it last year on a voluntary basis, and we did get a good response. One of our issues is going to be probably that the Order 745 -- we will not be able to pay it in the energy market going forward. So even the voluntary response we got, I'm not sure we would get again if we are unable to pay for it.

So we have put a proposal out there. We are very serious about keeping demand response as part of our wholesale market. We believe it is absolutely essential for a well-functioning market. So we believe there's a way to get there, but unfortunately the transition is -- prevents -- you know, causes some challenges going forward.

CHAIRMAN SCOTT: Okay. Thanks.

COMMISSIONER COLGAN: Our next speaker is Melissa Seymour. She's executive director of the MISO Central Region. Melissa has 16 years of experience and extensive knowledge of the energy industry. In her current role as the executive director for MISO's Central Region, she and her team are responsible for understanding the needs and the issues of stakeholders and regulators and communicating MISO's position on strategic MISO matters.

Previously, Melissa was the director

of regional markets and regulation for Iberdrola Renewable where she was responsible for advancing changes in transmission and operation rules to better accommodate renewable energy into the power system in both MISO and PJM and create business opportunities for the company.

Prior to Iberdrola Renewables, Melissa held various strategic planning, business development, and regulatory positions at the Bonneville Power Administration, PacifiCorp, Southstar Energy Services, and Southern Company Energy Marketing.

Melissa holds a B.S. in engineering science and mechanics from University of Tennessee.

Melissa, welcome.

MS. SEYMOUR: Thank you, and thank you for having me. I appreciate it.

It's important, I think -- we believe this is a very important topic, and we're going into 2014-15 thinking through the questions that you asked and preparing for what we -- you know, what we could have for a winter coming forward similar to the polar vortex.

We have projects underway that I'm going talk a little bit about that prepare us for this upcoming winter and get us ready and some changes that we've made since we've seen some of the lessons learned from the polar vortex.

I want to spend a little bit of time just talking about the events and kind of what we saw so that I can tell you why we have sort of the lessons learned that we did from the polar vortex.

Basically, we were able at the time to manage our system effectively and maintain reliability during the polar vortex, and we also assisted our neighbors when they needed it.

We did have an all-time peak demand in the winter on, I think, January 6th of 109.3 gigawatts, and that was about 9 percent higher than what we've seen our peak be with the current membership previously.

We had a maximum emergency generation event that didn't occur on the peak day. It actually occurred on January 7th, and that was after we saw some decrease in wind generation. We have about -- I think 10 percent of our energy is from wind generation or capacity on our systems from wind generation. We had reduced imports and fewer available generating units online. So we did have, on January -- or about 6th or 7th, we saw sort of the biggest hits to the system as a result of the polar vortex.

And really what -- when we talk about gas and electric, the coordination and some of the problems we were seeing, we -- you know, basically, we saw many generators on our system didn't run due to frozen components and other mechanical problems. We had -- especially our natural gas were idle because they were unable to obtain fuel. A third problem we actually encountered was generation of weather-related derates, meaning that the generation wasn't able to run -- was able to run but not at full capacity.

Because of that, during these extreme cold conditions, there were a number of -- significant number of units that weren't able to meet their contractual obligations to produce power when MISO called on them. So we did have a number of those forced outages due to operation.

Some of them were due to non-firm pipeline services, and MISO had to sort of rush to find and secure available and often expensive generation to fulfill those obligations and maintain reliability.

But, however, we -- we actually -- even though we didn't know that the 6th and 7th were going to be quite as -- you know, as significant as they were, we had proactively managed. We saw that coming a little early. We did call conservative operations on the 3rd which helped us, I think, manage the market generations to -- which has the market generators suspending all non-critical maintenance and performance. So we were able to call that, which we think was helpful, so we had more generation remain online than we would have had otherwise.

Just a little bit about what we found from firm versus non-firm gas in our footprint. We have about 40 percent of our generation in the MISO footprint is gas fired, and this is basically a breakdown of what -- the generation that has firm gas versus dual-fuel capability versus non-firm -- non-firm gas without a dual-fuel capability.

Going back to the event on the 6th, we had about 4, 4.5 gigawatts of gas-fired generation on MISO's footprint was unavailable due to dispatched -- due to weather-related gas restrictions. The problem actually grew worse and caused outages of about 6.6 gigawatts on the 7th.

Some of these weather-related gas restrictions were purely physical in nature; so -- meaning generators could not actually obtain the gas. However, some of the generators could obtain the gas, but it was at a very high price; so -- and they decided not to do that for economic reasons. The gas restrictions did have less of an impact on the dual-fuel capability resources. We saw that.

MISO, as a result of all this, though, doesn't plan on requiring firm pipeline service for gas-fired generators in the footprint. We instead are -- in an effort to better understand our situational awareness or improve our situational awareness, MISO is gathering more detailed information from market participants about the specific causes of forced outages and generation outages, including outages associated with non-firm pipeline service.

We're actually doing a very similar survey, I think, to PJM to try to -- as PJM to try to understand sort of what happened last year, what our generators have upcoming this year, and anything they foresee going forward. We sent that out, I think, last week, and we expect to get the results in a couple weeks and use that information.

But as our reliance on natural gas increases, we believe -- and I think you heard this from John -- that better coordination between the industries is imperative. We think it's improved, but we think the -- there needs to be more alignment between the sectors, and it's kind of critical in our ability to forecast -- you know, to bring the lowest cost to the consumers going forward.

So we're pursuing a number of initiatives to get there, and I'm going to walk through those to sort of -- how we're going to coordinate with the electric field and the natural gas industry and some other things that we're doing to sort of improve our situational awareness and the way the market runs in the winter.

I wanted to put this slide up because I think this diagram really represents -- just to give you a sense of the activities we do each day. This isn't different and this didn't change as a result of our winter -- the winter we saw. But during the course of business, we actually look at these activities every day as we manage the system. But during an event, some of these become -- happen with more frequency.

So we've been doing extensive preparation and coordination and using this winter preparedness sort of diagram to explain how we've been communicating with everyone over the last year. You know, we have daily calls with our neighbors as part of normal operations. We discuss the state of the system. You know, we ask for specific requests from market participants about other data and update their data when units are available and not available. You know, we make sure there's enough staffing both for us and at the sites to make sure that we can handle emergencies or things that are changing. So there's quite a few things that we do already, and I wanted to highlight those before talking about some of the things we're going into.

While the extreme weather conditions we did manage, we, as PJM is also doing, continue to explore how we can do a better job at our cold weather operations. We worked with our stakeholders and did internal reporting to try to figure out what specific lessons learned that we had and sort of develop issue statements around these lessons learned. We assigned them to various stakeholder committees for discussion and development and recommendations and potential resolutions, and I'm going to walk just very quickly -- but not too quickly -- through each of those issue statements.

So the first one we've been talking about is electric and gas coordination. One of the things that we've done, which we're pretty proud of, is on October 2nd we have -- we implemented the gas pipeline critical notification application. It actually went live in MISO's control centers. It's the result of this year-long field trial that we initiated with many of the pipeline owners across the footprint.

And with the reliance on this fuel increasing, as we see retirements occurring with 111(d) and some other MATS rules and replacements of natural gas, we've been working to enhance our communication protocols between gas and electric going forward. The web site application is the first in sort of a set of communications that we're going to have to access this critical pipeline information.

Later this year our control rooms will actually have integrated real-time displays for gas pipeline applications. And then in 2015 we'll be providing operators with more granular information about the impacts of gas pipelines on specific generators serving load in the area.

I think we talked a little bit about the -- you know, addressing the misalignment between the gas and electric day. You know, we -- because of this misalignment, gas generators have to submit their offers the next day, before we know for sure the gas will be needed. And so to keep this conversation going, MISO has put forth a straw-man proposal to the stakeholder community. It outlines basically how our electric markets could be better aligned with the gas operating day, and it does discuss moving our day-ahead process up a couple hours and our, you know, reliability commitment process up to be expedited; and we've put that straw man out, and we are getting stakeholder feedback related to that to see if folks think that would be a helpful alternative to the coordination.

Demand response resources:

One of the things that we learned, of course, during the polar vortex is we really needed to understand -- better understand the seasonal variation in demand response resources. You know, our load modifying resources on peak winter days indicated a reduced availability based on their availability versus summer. So we're looking at seasonal variations in these demand response resources because that can materially impact our resource adequacy in various seasons. And this inconsistency among the periods led us to evaluate -- or is leading us to evaluate the potential of a seasonal construct for these -- for load modifying resources, and we're actually also looking at that for generation resources as well. So we're looking at that more broadly.

We also implemented a tool, a voluntary load management -- or a -- an LMR -- I'm sorry -- load modifying resource automation tool to help our situational awareness. So that tool actually helps us understand the seasonal variation and the differences in the LMR resources, and so that's been in place for the upcoming season.

Communications:

I mean, I think this is one area -- the protocols and communications protocols -- where we did do a pretty good job, and I think we're just continuing to make sure that we have a review of emergency operating procedures, that we're reviewing with our neighboring entities emergency operating procedures and protocols just to make sure that we're ready when an event occurs.

We also figured out that we have -- we need to leverage the tools that we have in-house, and we have this look ahead commitment tool that looks out three hours, and a lot of the operators at the time weren't using the tool to see what was going to happen three hours ahead, and the tool was telling us that we might have some issues. So we're increasing the situational awareness and being able to use that tool to actually project what's going on in the control room so that folks are ready for what's happening three hours ahead.

The other thing is that we -- you know, to do post-event analysis. When an event likes this happen, you wish you had all the data to support a report. We have an outage system that didn't really capture a lot of information about the reason for the outage or, you know, why units were not being committed, you know, what the cause type for a derate or an outage was. So we've improved that outage system to include those pieces in it so that, when we have an event, we can actually do a better job of understanding what the reason for that event occurred.

And the last two are really unit performance and we have market enhancements. But, you know, under unit performance, this is really, you know, our unit commitment process. And we talked a little bit about we need to address the ability to be able to commit resources appropriately and not -- and not, you know, do it in an emergency sit -- you know, always being an emergency where we're creating headroom and other -- or we're creating a lot of uplift. And so we've -- you know, we think the electric-gas coordination will improve our situational awareness so that fuel restrictions -- we understand them better. We'll be able to commit units appropriately.

I think the other thing we're looking at is increasing our headroom margin when we see a cold weather event happening so we don't have to commit emergency resources as often.

We are posting -- and I think we've already posted -- annual reminders to prepare for cold weather and address mechanical failures. So we're posting information so people understand it. And we haven't done what PJM does yet, but we're looking at longer term sort of winter preparation, evaluating unit testing and processes prior to winter so that, for those units that don't typically run or run on dual fuel, that they're tested before the winter season. So those are some things we're going to do to improve unit performance.

And, finally, we have market performance measures. We -- you know, we did see, of course, energy prices in the footprint increase due to the polar vortex and outages and high demand. We think that was actually a natural consequence of our tightening conditions at that time. So we believe they worked -- the markets actually worked as intended.

However, you know, right after we issued our maximum generation alert, energy prices actually dropped, and prices got depressed pretty significantly as a result of these emergency actions we were taking. So we were limiting non-firm exports and commitment of emergency only resources, and so it didn't really provide the right price signal to the market that we needed the generation. So we're doing some things to be able to design our pricing under emergency conditions better to better impact that so we don't see that going forward.

We're also launching extended marginal -- locational marginal pricing, which we actually delayed a few months -- I think we're doing it now in December -- which will help price setting for our emergency demand resources and our block loaded resources. And, you know, we're trying -- you know, that, combined with redesigning under emergency conditions, will help send the right price signal that we need units online.

And, finally, given that natural gas may be more volatile in the future for us in the winter season and our reserve margins are diminishing due to the coal retirements, we're looking at energy -- our energy offer cap and other caps that we have in the market. We haven't made any decisions on moving those or changing those, but we're evaluating the need to be prepared to have to do that if we see a condition that would occur.

So with that, I will -- that's all I have.

COMMISSIONER COLGAN: Okay. Thank you. There's a lot going on; right?

MS. SEYMOUR: Yeah.

COMMISSIONER COLGAN: Your shops have been busy, it sounds like.

Questions from the panel?

Commissioner McCabe.

COMMISSIONER MCCABE: We had an Organization of PJM States' meeting last week. So we heard about some of these issues then too, and so I'm interested in hearing more about dual fuel. It sounds like MISO has about 25 percent dual fuel, and I know that PJM's looking at increasing dual fuel. Dual fuel is less expensive than firm gas, but just, you know, to what extent will this be increasing over time, especially with the coal plant retirements? And is it mainly baseline or units that you have to call on? And just more thoughts on the whole dual fuel.

MR. KORMOS: Yeah. We're pretty similar to MISO. We have about 20 percent dual fuel right now. And, as you said, I think what we're looking to do, particularly through our capacity markets, is really let the generators pick the best alternative.

So one of the things we really want to push on the gas side is, you know, the ability for them to get the gas packages they need to firm themselves up to be available when we need them -- but not necessarily at some of the costs we unfortunately had to deal with in the previous summer -- and be able to compare that against dual fuel.

Because, ultimately, you know, we want to make the most economic decisions, and the fact of the matter -- you saw the numbers. We don't need every unit in the winter. So we don't necessarily want to pay for what we don't really need, but we do want to pay for what we do need. So I think that's our challenge right now.

And, as I said, I think what we're doing is coming up with performance standards for the generators: This is what we expect. This is what we need from you. This is the operational flexibility we need. The incentive will be increased capacity payments, but there will be a stick. There will be penalties if you fail to deliver, and then allow the generator to then figure out how to meet that the best they can. And then, ultimately, for us to select then the most economic subset of those resources.

MS. SEYMOUR: I was just going to say that we haven't actually gone that far. I mean, the generators have to make the decision based on the economics whether -- in our market whether it makes sense to, you know, put in dual-fuel capability. I don't think we even -- we've instituted sort of the incentives that PJM has at this point. I know that we are looking at doing something similar, but I don't think we feel like we're at a point where that's necessary in our market.

As we get more gas intense going forward with our coal fleet retiring, I think we will probably be in a position where we're going to need to provide similar sort of incentives, but we haven't -- we haven't actually gone that far yet.

COMMISSIONER MCCABE: Thanks.

COMMISSIONER MAYE: I have two things: The first one is a comment for Mike. I think when you talked about your capability testing and checklist and you mentioned that that was something that you did not do last year, and then, you know, last year happened and you're adjusting and making changes. I just want to say I think that's great because I think that's what's needed, not just within relation to this particular problem, but more importantly clear across the board to industry. So just wanted to commend PJM on that.

Second, Melissa, I wanted to ask you, when you talked about the gas-electric coordination and that you guys have kind of already put a bit of an implementation plan together and some feelers out there, what has been the feedback from the gas and electric industries, respectively, and are they realizing this is as crucial as we know that it is?

MS. SEYMOUR: I think so. And we -- we had -- we started a few years ago the Electric-Natural Gas Coordination Task Force, I think, as we were looking at retirements of the coal primarily due to MATS, and we were concerned about our supply switching from coal to gas because we've been pretty coal heavy.

I think the coordination -- as the gas pipelines and as the suppliers -- they got more involved, they realized the importance and the interconnection between the two as part of that process, and I think that has helped us through the winter time period because we had those relationships with the industry three, you know, to four years ago as we were beginning that task force.

And so I think -- I think they see it. I -- you know, I don't know, until we start increasing our gas supply, whether we're going to feel, you know, more -- I mean, they've been very -- the gas industry has been very willing to communicate and provide information and work with us for these things, but I think that should continue.

COMMISSIONER COLGAN: You mentioned this issue of evaluating seasonal variations to see if there are market enhancements that are needed. Can you unpack that a little bit, and just talk a little bit about what that -- what you mean there?

MS. SEYMOUR: Well, right now we have an annual sort of capacity construct that looks at the peak hour in the summer and determines what your resources would be for that peak hour in the summer. And, as we mentioned, demand response and some other resources may -- and gas resources may have seasonal variations in their output as a result of, you know, just changes in season and the weather.

So we're actually looking at having a construct that's not annual, but it's going to be some sort of seasonal where we have -- you know, the season could be a winter-summer. I mean, it could two seasons or it could three where you have shoulder hours and shoulder periods in summer and winter where you're able to say my resource has, you know, an amount of capacity during the summer, but it's derated in the winter, and it can provide something in the shoulders that looks like this. And same for demand response.

And it's something that we're working

through the stakeholder community with right now to see if that's something. We've gotten a lot of interest from the stakeholders related to that product.

COMMISSIONER COLGAN: I think that -- that sounds interesting to me -- a creative evolution of the thinking on how to make things come together. I think that sounds interesting.

Did you have something else?

COMMISSIONER MCCABE: No.

COMMISSIONER COLGAN: Any other questions for our panelists?

Okay. Well, we're -- yeah, thank you very much.

MS. SEYMOUR: Thank you.

COMMISSIONER COLGAN: We're about five minutes past -- over time, but why don't we take a ten-minute break and try to get back here by 3:00 o'clock? Will that work out for people?

(Short recess.)

COMMISSIONER COLGAN: Okay. Well, our next panel is going to be the local distribution companies in Illinois. That's going to be Ameren Illinois. We have Scott Glaeser;

right?

MR. GLAESER: Glaeser.

COMMISSIONER COLGAN: Glaeser.

Nicor Gas, Shirley Holmes.

Peoples Gas and Coke Company and North Shore Gas, Richard Dobson.

And for MidAmerican Energy Company, we have Brian Wiese. Wiese; right?

MR. WIESE: It's Wiese, yeah.

COMMISSIONER COLGAN: Mr. Glaeser graduated from Missouri University of Science and Technology with a bachelor of science degree in mechanical engineering. He started his career in the steel industry working as a combustion engineer at an integrated steel mill, National Steel Corporation, which is now U.S. Steel. He was responsible for energy supply, distribution, and combustion systems engineering.

In '91 Scott moved to Union Electric with responsibilities for natural gas supply supporting the LDC and gas generation facilities. With UE's growth and the acquisition of CIPS -- which formed Ameren Corporation -- CILCO and IP, along with the significant growth of the gas business, he was promoted to various management positions up to the vice president level over various areas of gas business, including gas supply, gas control, storage operation/ engineering, transmission engineering/ construction, pipeline integrity, management, metering, gas training, regulatory compliance, and fleet services. That's a big job description.

Scott's current position is vice president of gas operations and development for Ameren.

And, Scott, welcome and look forward for your comments.

MR. GLAESER: Thank you, Chairman, and thank you, Commissioners. It's a pleasure to be here this afternoon.

I think one of our goals here as the Illinois gas utilities is to give the Commission some confidence as we go into this next winter that we are well prepared; and, indeed, I think within the next hour you will find this true.

So we can't look forward to the coming winter without looking at the prior winter, at some of the lessons learned, and some of the operational problems we had.

Last winter, without question, was probably the most difficult winter we had in all aspects, whether it be demand, operations, of course, weather, snow, wind, and so forth, in more than a quarter century.

We had -- of our peak design day, we reached about 97 percent of our peak design day on January 6th of the past winter. Then, overall, the season itself in total from November through March, we exceeded our 30-year maximum normal winter weather. So we basically had the designed winter that we had designed for every year for many years now.

The good news is we provided gas to all of our customers with no curtailments, no operational flow orders, and we did not declare a critical day.

In addition, we had a stable PGA for the entire winter which averaged about $.54 a therm. That comes by no coincidence or by accident. That is from very intense system planning, capacity resources, planning for the peak design day of 30 to 35 years plus, pipeline capacity, investments in our gas infrastructure and especially our storage fields. So we're very proud that we made it through the last winter with no real incidents and keeping our customers whole and warm through the cold winter.

That, in spite of significant operating problems we encountered with several of our interstate pipelines, and probably the biggest problematics we had was with NGPL. And to give you some examples, on NGPL's Amarillo Line, we experienced extremely low operating pressures from them to a point where our transmission system pressures came into parity with their transmission line pressures. That's a huge problem in the gas industry as a whole. That means no flow is happening.

Even more problematic for us was that NGPL's delivered storage service -- the DSS storage service -- was actually -- could not withdraw in February and March, and then we were actually ordered to inject in that time frame. So not only did we lose withdrawal capability, which was critical for us, we actually had to inject. So we had to actually acquire more gas at specific points and inject in those storage fields when we needed that gas at our city gate stations.

Why that's so important is that a lot of our on-system storage fields are aquifers. So as we get deep in the winter period, February and March, my deliverability from the aquifers declines significantly. I need that DSS storage to help fill that gap, and right when I needed it the most, we lost that deliverability of NGPL. That was very difficulty. Luckily, with our operations, our storage field personnel, our gas supply folks, our gas control, we kept the systems going in spite of that loss.

Other issues we ran into with NGPL:

The Amarillo main line capacity was reduced by 50 percent. In other words, of all the firm pipeline capacity we hold on the Amarillo side, which is the west side of their system, we lost half that deliverability and for extended time periods for two different periods. Again, this is difficult to take in a peak winter like we just had.

The one key part of our system planning that basically helped save the day is that we have a capacity reserve margin above and beyond our peak design day. That capacity reserve margin came into play and did exactly what it was supposed to do -- is that, when we lose certain resources, we use that reserve margin to fill that gap, and that's exactly what we did. That kept that gas flowing to our customers.

COMMISSIONER COLGAN: What is that reserve margin?

MR. GLAESER: It's approximately 3.4 percent for our entire system.

So after the winter is over, we had a series of meetings with NGPL executives -- as did Peoples, Nicor, and other utilities -- and by no means were those meetings very pleasant. We had to lay it on the line to NGPL: Either you get the system back with a high level of operational integrity, or we will move elsewhere.

And why that's important is that in Illinois we are blessed with many pipelines across the state, and Ameren Illinois operates on ten different interstate pipelines. So, basically, we made it clear, if you don't get your system back in operational order, we're going to start shifting capacity to other interstate pipelines and start leaving your system. That's a pretty strong message to send to any pipeline.

So they got the message. They have been doing many projects, including storage field enhancements in several of their storage fields in the market zone. They're putting in more storage inventory in the market zone this winter, at least another 10 Bcf.

And even though we trust them, it's the old trust but verify. So NGPL sends us and Peoples and Nicor weekly reports on their storage injection inventory levels so that we can monitor their progress for this coming winter, and they have been on track so far.

Other issues is that we are improving our communications and coordination with the interstate pipelines during peak operating periods. We have done this historically, but we're ramping up those communications even more now as we've come -- face the oncoming winter. So this is typically daily calls with the interstate pipelines between our gas control center and the interstate pipelines' gas control center to coordinate operating flows and pressures and so forth.

COMMISSIONER COLGAN: Can you -- I don't want to distract you too much. Before you move on from this issue of the pressure and the NGPL transmission line became equal with your distribution system --

MR. GLAESER: Yes.

COMMISSIONER COLGAN: -- what was it that happened on their side of the distribution -- the transmission system? What happened over there that had that occur?

MR. GLAESER: There was cascading effects, but in summary, their storage realty was declining rapidly. They lost the ability to withdraw from their market area storage in Iowa and Illinois.

They lost some of their compressor stations. They had compressor station failures. So they lost horsepower to push gas down the transmission system.

COMMISSIONER COLGAN: Was that weather related -- the compression --

MR. GLAESER: We think it was a combination of weather and maintenance practice. Part of the discussions we had with NGPL is you have to have critical spares at your key compressor stations -- critical things like rings, pistons, cylinder heads for those compressors -- that, if you have a failure, the parts are there at that station, and you get the rebuild started immediately and not wait to order parts.

But there was multiple cascading effects that caused this, and NGPL is addressing all these different impacts.

Yes, Commissioner.

COMMISSIONER DEL VALLE: Have those maintenance issues occurred in the prior years?

MR. GLAESER: Not to this extent. There's been problems with certain compressor stations and certain storage fields over historical years, but just isolated.

This winter NGPL experienced

cascading problems on both sides -- both the Amarillo side, which is the western side, and the Gulf Coast side, which is their eastern system.

As a matter of fact, we took this so seriously that we sent some of our key personnel out to NGPL stations to personally inspect some of these modifications and enhancements. So we take this very seriously.

Also, we learned lessons on our own system. Even though we didn't lose any customers during this whole period, we did experience low operating pressures in certain parts of our system. We took those lessons, and this summer we've been making enhancements to our transmission and high pressure distribution systems to make sure those low pressure events don't happen in future winters.

So, basically, our infrastructure is going to be better prepared than last winter even though we operated very well last winter. So it's actually enhancing our reliability going forward.

We've already had some good discussions about some of the regulatory responses to this, including the FERC gas-electric coordination and also even Commissioner Moeller introducing the new docket to look at physical gas trading platforms.

From Ameren Illinois' point of view, change in the gas day or changing intraday nomination cycles -- that's all good and will improve operations; but at the end of the day, there's got to be more steel on the ground, there's got to be more pipeline capacity built, there's got to be more market area storage built to help handle this growth and demand, especially from electric generation. That has to happen.

And part B to that is that these generators have to acquire firm pipeline capacity to support their generation. They can't rely on interim transportation capacity and wonder why they've been curtailed when it's 20 below zero in Chicago. That just doesn't work.

I hope I emphasized that point well enough.

COMMISSIONER COLGAN: Well, to be able to get the firm transmission, you have to have increased capacity to deliver; right?

Isn't -- isn't -- don't those go hand in hand?

MR. GLAESER: Yeah. Certain pipelines, which are fully subscribed and there's no available front capacity, there will have to be expansion projects, and I'll talk about this at the end of my presentation. There is some expansion projects proposed in the Midwest and in Illinois in particular that will help solve this problem.

CHAIRMAN SCOTT: What's the magnitude there? How big of an expansion are we talking about?

MR. GLAESER: Well, for example, the Tallgrass Prairie State Project -- that's up to 1.2 Bcf of expansion capacity from Rockies Express north to Chicago.

CHAIRMAN SCOTT: But I mean -- I didn't ask it very well. I apologize.

Based on what you were just saying about the need to have more capacity, looking out into the future, not just the projects that are planned right now, what's that -- how large are we talking about in terms of the percentage of the total that we have now? I mean, are we looking at 20 percent expansion from what we have now?

MR. GLAESER: Yeah. It all depends on your growth projections for demand because you have demand for gas generation, and there's two tranches of that: this existing generation fleet that's going to be utilized a lot more, and then this new gas generation that's built to replace retiring coal plants. And then you layer on top of that more industrial use of natural gas, which we see growing already, and then even beyond that we are seeing more growth in the fleet demand for natural gas, CNG; LNG for trucks and cars.

So if you start adding up all that, you're talking 10, 20, 30 Bcf a year -- or per day growth. That's significant. Now you're talking 25 to 35 percent of new expansion capacity.

It also can be very regional too. So up in the Northeast, they probably need, you know, 40 to 50 percent expansion capacity. They're that tight. They're already so constrained now without any of these new generation facilities coming online.

CHAIRMAN SCOTT: Thanks.

MR. GLAESER: Looking forward to this winter, again, we have all of our long-haul firm pipeline capacity all under contract with the interstate pipelines, including our reserve margin. So that's an important part of our portfolio.

We have all of our firm gas supply under contract, primarily with producers for the coming winter, both to meet our maximum peak day demand and to meet our maximum winter demand; and more importantly -- or just as important -- and Rich will expand on this -- is that we also have the ability to ratchet down in case we have an extremely warm winter. So we have to prepare for the coldest winter in 30 to 35 years, but we also have to operate in the warmest winter in 30 to 35 years. Both paths are important to us.

On the price side, we have -- 75 percent of our expected winter demand or normalized winter demand is hedged against price volatility. That includes the gas I have in storage, both on-system and leased. It includes fixed price gas and then also financial hedged gas. That makes up about three fourths of my expected winter demand, all within the $4 range. So most of the gas is already ready for the customers at very reasonable prices.

And, finally, our storage. We are on target to be filled at both leased and on-system storage by November 15th, ready for the winter demand.

I think our key statement we'd like to make to the Commission is that we're fully prepared for this winter season, and we expect very stable PGA rates for our customers. We're looking at a range from $.53 to $.55 per therm for our customers this winter even if it gets very, very cold.

This graph is our storage inventory starting with last winter, and what you'll note is that decline is from that extreme winter we had. That's the lowest I've seen our storage inventory levels, period. So, believe me, we were getting a bit nervous late March and April, but we made it. More importantly, you see we've filled up and recovered those storage facilities, and the dotted lines are our expected injections for the next three weeks, which we're on track to make. So we'll be at full storage inventory November 15th, and we'll be ready for winter.

And, finally, my last slide. As mentioned, we are blessed in Illinois with excellent pipeline capacity. We are the crossroads of pipelines in the Greater Midwest -- actually for the country, if you look at it that way.

New expansion projects include the Rockies Express Pipeline, which is going to go bi-direction. Rockies was built to move Rockies gas all the way east across the country to the Northeast. It ended up being on top of the Marcellus shale. So they now, wisely, have made their pipeline bi-direction or are making it bi-directional now so they can bring in Marcellus and Utica gas to the Midwest. The Rockies gas comes in from the west, and guess who is in the middle of that target. It's Illinois. So we have a great opportunity in the state of Illinois to take advantage of that.

Which leads to the Tallgrass Project, which takes the gas from the Rockies Pipeline which is in red there, directly north to Chicago hub and then basically accessing all of the Illinois LDCs. I think MidAmerican might be a bit far away, but the rest of us are right in path.

There's some other projects too with Energy Transfer Partners, Panhandle Eastern. Similar type project where they got the shale gas coming into the eastern part of their system. They're going to be moving that to the Midwest as well, and ANR has another project as well.

So, again, we are blessed with significant pipeline capacity resources and access to all these new shale plays in the U.S.

And that concludes my formal presentation.

COMMISSIONER COLGAN: I don't know if you can answer this question in simple terms, but I was just kind of wondering what you're -- what you're scheme for contracting looks like. How do you layer that in terms of -- you say you have it all contracted for this year. Do you go a few years out with different percentages of it negotiated now?

MR. GLAESER: I could talk a couple hours about that, but I'll be very succinct. We intentionally layer our pipeline capacity in three-year tranches. So every three years we have a certain percentage of our portfolio coming due, and what that does for us -- it does two things: We can adjust according to demand. So if we have demand loss or demand growth, we can make adjustments there. More importantly, it gives us the ability to move to other pipelines if needed.

COMMISSIONER COLGAN: Yeah. Okay.

MR. GLAESER: We've already done some of that with some of our pipelines for this coming winter.

COMMISSIONER COLGAN: All right. Thanks.

Okay. Our next speaker is going to be Shirley Holmes, and Shirley is the director of gas supply at Nicor Gas. She previously was the manager at Nicor Gas' gas supply department, and Shirley joined Nicor Gas as a staff accountant in August of 1988.

Shirley has 26 years of energy

experience, mainly in gas procurement and gas accounting. Shirley's current responsibilities include the contracting and purchase of all gas supply for Nicor gas, gas trading, and gas scheduling, financial hedging, and regulatory support for gas purchasing activity.

Shirley is a graduate of the University of Arkansas, and she earned her bachelor's degree in accounting. In addition, Shirley has earned a master's degree in business management from Aurora University.

Welcome, Ms. Holmes, and look forward to your comments.

MS. HOLMES: Thank you.

Some of my presentation will sound very similar to Ameren. We all have some similar experience.

But I'm going to start with slide two with a look at our peak day sendout, and this is just to give you some comparison of what our peak day looked like on January the 6th, with the common theme here today, compared to the previous years starting with the year 2000.

Our deliveries for January the 6th

was 4.583 Bcf, and this -- to give some perspective to this, our coldest day was January the 18th, 1994, with an HDD of 80 degrees, and we had 4.6 Bcf sendout.

Some of the challenges that we experienced this past winter:

November was 22 percent colder than normal. We had 72 Bcf more deliveries than planned, and we purchased 75 Bcf more than we had planned under normal weather conditions.

We had the similar experience with NGPL as the other LDCs.

One unique factor about Nicor is that one third of our system demand has no access to system storage, and so we are relying strictly on the pipeline for those feeds.

Ability to take gas from NGPL dropped significantly for the same reason: low pressure, deliverability, and compression issues.

NGPL called numerous OFOs/force majeure restrictions throughout the winter. The challenges were greater as the winter moved on.

Managing some of the challenges for this past winter:

We were able to use our on-system storage to meet the peak day and specifically peak hour needs, and this is very helpful when the pipeline restricts hourly takes.

We targeted non-NGPL supply to help meet our needs, and we talked to the pipelines often, and in the case of NGPL, several times a day.

COMMISSIONER COLGAN: Their storage is mainly in aquifers? Is that --

MS. HOLMES: Mainly aquifer storage, uh-huh.

By maintaining consistent communication with the pipelines and our large transportation customers and also moving our takes around our system, there were no interruption in customer service.

Also, similar to Ameren, our gas-electric coordination -- we are working with our customers, RTOs, AGA, and FERC to understand and address gas-electric coordination issues.

COMMISSIONER COLGAN: You say you didn't have any interruptions in service. But wasn't there a point where you had to contact some of your major users of natural gas that they may have to cut back or you many have to cut back on them?

MS. HOLMES: Well, we did contact some of our large customer and ask them, to the extent they had alternative fuel or dual fuel, to cooperatively not use on certain days. There was a few days there that we did ask that, but we did not interrupt anyone.

COMMISSIONER COLGAN: Yeah. And that was driven by this problem that you had with the supply.

MS. HOLMES: Yes. It was directly related to the problem we were having with NGPL.

COMMISSIONER MAYE: But had -- had no one -- I'm not sure if you have any stats on how many people actually complied with that and did use an alternative source; but had they not, then you -- I mean, the issue could have been there -- that you would have had to interrupt some consumers; right?

MS. HOLMES: We were being proactive by asking, and to the extent our customers were able to do -- if they chose not to, we did not feel that we were -- would have lost some customers because we were not at the point that we had peaked all of our services.  But we were just being precautious and asked for that voluntarily.  We did not know how long NGPL was going to be impacted.  Some of the problem that were existing, we weren't sure.  So we were just being proactive and asked some of our customer to cooperatively do this for us.

COMMISSIONER MAYE:  Do you have any idea about how many customers actually decided to use their alternatives, or you don't know?

MS. HOLMES:  We may have talked to -- I would say -- and maybe Lilly can help me with this.  But we may have talked to about 40 customers or more, but it was not -- we did not go through the whole picking list.

COMMISSIONER MAYE:  Okay.  Thank you.

MS. HOLMES:  Okay.  This slide is our design day, and as you can see, our design day for this coming winter is 5 Bcf.

And what I wanted to mainly point out is some of our sources of supply.  Our pipeline transport and leased storage would make up about

2.3 Bcf of that, end users .6, on-system storage is 2.5, and that leaves us about a half a Bcf of pipeline reserve.

We do not expect any significantly improvement over NGPL's performance last year if we have similar weather. So for that reason we have increased our reserve margin to 10 percent for this coming winter.

COMMISSIONER COLGAN: Okay. How much of that did you have to get into last year -- your reserve margin? If you don't know --

MS. HOLMES: Yeah, I don't know offhand.

Okay. So for our supply and storage for this coming winter, we have secured 100 percent of our firm supply to fill our winter transport, and also our storage is planned to be filled by November the 10th -- on-system storage.

Nicor Gas' transportation capacity and other upstream pipeline provide the utility with access to all major supply regions, and this map help us to visualize where the gas is sourced and transported to Nicor to our city gate.

Here's a look at our storage fields

and our injection updates in preparation for this coming winter. As you can see from the dotted line, the dotted lines are planned, and our -- the solid lines for each one of those fields are the actual fill that we've made so far. So we are on target with our on-system storage.

Preparation for this winter:

Again, we've increased our reserve margin mainly with non-NGPL city-gate firm supply. We've secured 100 percent of our supply for the transport. We also have filled our leased storage. We have met our plans and have those ready for this winter as well.

Also, we have either scheduled or completed winter-readiness check with all of our pipelines and, in some cases, rechecks.

Also, for future supply to the market, we continue to explore, look at bringing some of the shale supply here to the market. Actually, some of the projects that Scott mentioned -- we're also looking at those projects. The Tallgrass Prairie State Pipeline Project, the ANR East Project -- we are looking at those project very seriously to see what we can do to diversify our supply.

We are looking at our system, facilities improvements that would help make our own distribution system more capable of bringing in a diversified supply and make it more reliable.

Those are some of the things we are looking at and what we've done to make ourselves ready for this coming winter.

COMMISSIONER COLGAN: Your transportation capacity map -- I was just wondering if the circles were proportional to the amount, or is just, in fact, the geographic area of --

MS. HOLMES: They are the geographic area.

COMMISSIONER COLGAN: Yeah. So has this map changed significantly over the last five years or so?

MS. HOLMES: No, it has not.

COMMISSIONER COLGAN: Okay.

MS. HOLMES: No. We do have our transport shaped similar to Ameren where most of it is about three years, and it's staggered to fall off at a different time so that we're not negotiating all of it at the same time, as well as if the demand would change, we would be able to accommodate that change.

COMMISSIONER COLGAN: Thank you.

Okay. Our next speaker is Richard Dobson. He's the manager of gas supply, Peoples and North Shore Gas. Mr. Dobson has been with North Shore and Peoples since June of 2006.

He's been employed by the Integrys family of companies since 1992 and been involved in the natural gas industry since 1985. With Integrys, Mr. Dobson has held various positions in regulatory gas supply, business and contract administration, and asset development areas.

Prior to joining Integrys, Mr. Dobson was employed by the California Public Utilities Commission in both advocacy and advisory positions with an emphasis on natural gas rate and policy activities.

Mr. Dobson has a bachelor of science in geology from the U of I and a master's in engineering from the University of California, Berkeley.

Welcome, Mr. Dobson.

MR. DOBSON: Good afternoon, Commissioner. Thank you for letting me present today.

I'm going to go in a slightly different pattern than what's gone on so far. I'm going to start first with the gas-electric coordination at slide two, Scott.

Peoples Gas serves two small gas-fired electric units. They're under negotiated rates so that we talk to them all the time. For y'all, it's under -- called a Rate 5 for us.

During the winter '13-'14, they were restricted on the ability to burn because they did not have a firm contract arrangement with us. They are interruptible in the winter. We are currently talking to them about new contracts.

North Shore Gas does not serve any substantive gas-fired electric generations. There's a small one in one of the towns, but for all intents and purposes, they're on a tariff rate; so they're within the system already.

We have, as both the utilities and as

Integrys generally, been very much involved and actively participating in the FERC gas-electric coordination issues, as well as with the NAESB issues, both with AGA and with EEI or the Edison Electric Institute.

Integrys is a combination utility company; so we do cover both sides. One of the things we did find through our own internal discussions is that the gas and electric folks talk different. We've had to --

COMMISSIONER COLGAN: Different languages?

MR. DOBSON: Yes. We've had to learn how to understand what other each is asking for and seeking even though we're talking about exactly the same thing.

As a result of our efforts internally, we have -- through both NAESB and FERC, we support the need for more pipeline capacity. But that capacity is especially those that meets the needs of the electric generation units, and we want capacity that's brought to the market that does not denigrate the ability for the LDCs to continue to meet their requirements.

We're all in favor of having new capacity brought in, but should the LDCs for the LDC core customers have to bear all those costs? Or should we lose the ability to have the flexibility that we have today?

We're all in favor of having some of those changes come on, and certainly the capacity is going to be needed. As Scott noted, if you look at the Northeast, they need a lot more capacity than they do in the Midwest.

We're in favor of regional solutions versus national solutions. In other words, let's solve some of the questions in steps. Oftentimes you make a broad-ranging, wide decision that has unintended consequences. I'm not saying that's where we are today. But that's why we support regional versus national solutions.

We have supported and continue to support the revised nomination schedule, but we have not and at this point do not support the change of the gas day to start at 9:00 A.M. So if we look at it and say buy and be able to pay for the services that you need, if that requires additional facilities to be built, we can support helping build those facilities, but let's make sure that the people that are causing those things to be caused are incurring those costs and they're able to be compensated for it.

I know that last part is not an easy question. But at the same point in time, I don't want to necessarily see the cost of me serving my gas ratepayers to go from a dollar to ten dollars because the cost of the electrics went from a dollar to a dollar ten.

I know the numbers are wrong, but let's just put it in perspective.

Typical winter challenges:

We've talked very much about how to meet the cold winter day. Well, from my perspective, it's almost as difficult to meet the warm winter day as well. So we need to build a portfolio and design for both a peak day and a warm winter and a warm day.

We forecast design peak days. We test winter supply/demand scenarios that cover the whole range, and we also cover the extreme supply/demand days for both warm and cold days in particular.

To put it in context, for this winter coming up, for winter '14-'15, we are designing to meet a -- for Peoples Gas to meet a design day of 2.1 Bcf. A warm day is .35 Bcf. It's one sixth. Can I drive the bus right down the middle and be able to swing up to the 2.1 and down to the .35? I hope so. We certainly are trying, and that's how we put our portfolios together to do it.

For North Shore Gas it's very similar. Our peak day is designed at 444 M decatherms or a thousand decatherms versus the warm day of 60. So that's a factor of seven.

When we're doing our demand forecasting, we're looking at not just the season but the days as well. We buy too much baseload in a warm scenario, we end up selling what could be perceived as very expensive gas into a very poor, very low-priced market. We have to balance that with having to buy a lot of spot gas in the cold winter, which can be very, very pricey, as we saw last winter.

We also want to do this and design our portfolio such that we take into consideration how to minimize restrictions on our transportation customers. For Peoples Gas and North Shore Gas, approximately 40 percent of our annual throughput is gas that -- and I'll put it perspectively. I'm not responsible for buying. I am responsible for handling and making sure we get it delivered to our customers. So four out of every ten units that comes through our system is brought to me by somebody else, and they want me to redeliver it to themselves as well. We don't want to have that relationship upset any more than necessary either. But we also don't want to and have to balance the obligations we have to the transportation customers to the sales customers. So, in essence, I'm trying to tell you we have to balance a lot of different things. Very similar to your jobs: You're balancing a lot of different stakeholder obligations. It's not a simple task.

For the winter preparedness, we have gone through and our design day is revised. In 2013, our design day for Peoples was just over 2 Bcf, and we're now just over 2.1 Bcf -- about a 4 percent increase. North Shore saw about a 6 percent increase.

We have adjusted our pipeline storage and transportation assets. Some of that's been acquisition. Some of it has been reassignment. Some of it has been planned utilization in a different way.

Our storage injections are on track to meet our November and December targets, and I use November and December. Most of our leased storage services, the ones we take from the interstate pipelines, we have a November 1 target. For our in-house and our owned -- our company-owned storage, that target is more in the early part of December. We are on target to hit both of those with some additional storage that we've purchased as well. So it's not just what we've already had but those additions that we've put on.

Our winter price hedging is complete. We, like Ameren and Nicor, put hedges on throughout the year. My current hedge season -- I'm out hedging winter -- or summer '16 already. So we're that far out. My winter '14-'15 hedging is complete. And our winter commodity acquisition is essentially complete.

For North Shore Gas, we did use a lot of propane last winter, and we did have to refill our propane tanks, and that has been completed.

Last, as in noted by Ameren, Peoples Gas and North Shore Gas have built cross-functional teams that address both the supply and the operational level. On the supply operations level, we meet every morning between gas supply, gas control -- those people that make sure that the gas comes through the city gate meters -- our gas storage people, and our transportation services. Those are the folks that interact directly with our transportation customers.

On the utility operations level, our gas control, gas distribution, the customer Care -- the people that answer the phones and have to go out and make the call outs and things -- as well as our corporate communications -- so that we can get the message out -- are all meeting as well.

Last winter those meetings went on almost every day. I can tell you for certain that the gas supply meeting happens every day.

That's part of the meeting I'm in the office for every morning.

The utility operations, during the colder parts -- they were on the phone every day as well, and I'm not talking about five days a week. I'm talking about seven days a week. That's how we're preparing.

When RBN was here, they noted that there's a lot of pipes that come through the Chicagoland and the Midwest area. Well, a lot of pipes had many problems. NGPL probably the biggest one of the problems that we faced, but quite honestly, there was a whole list.

OFOs means operational flow orders. That's where the pipeline comes in and says, "You have to do this at this point." Critical time -- that's also considered an OFO, but it usually has much stricter requirements within it, and it tends to double, triple, quadruple the cost of making a mistake.

So under a normal mistake, if we take too much gas, it may cost me a dime. Under an OFO, it may cost me a dollar. Under critical time, it could cost me up to $10. That's per unit. Yes, they get very pricey very quickly.

And, lastly, for NGPL, they had that storage directive where they directed us to buy a substantial amount of gas that, quite honestly, I didn't want to buy. Had to keep the system up, though.

Getting off NGPL for a moment, you can quite honestly see that there were others: Northern Natural Gas -- that's what NNG stands for -- ANR, Panhandle, Guardian, and Viking. They all serve -- all except Viking serve indirectly to Peoples Gas system. Panhandle has to come through Trunkline, but they all had system operation issues. The Viking operation in particular was affected by an explosion on a pipeline in Canada feeding them. That affected one of my affiliates, Minnesota Energy Resources, but it also affected ANR and affected us right on down the line.

Essentially, when it's cold, you're running a mechanical system that has a big potential to fail. Lots of things moving. Lots of things can be done. Scott talked a little bit about that with NGPL with the increased maintenance and things like that, and we're all working at that. But just remember, just like when it's cold on us and we're out shoveling that snow, there's a lot of stress on our bodies, and you're working out in the cold weather. The system's mechanical as well. It's not to make excuses, but it's to help understand what can go wrong.

With respect to the pipeline activities, for winter '13-'14 response, NGPL is performing compressor maintenance and additions. And, in fact, they have just recently, on or about October 20th, put a new compressor unit online in Iowa which is expected to increase their peak day withdrawal capabilities. That allows them, NGPL, to be a little bit more reliable.

They are repositioning compressor replacement parts and the maintenance ability. And they have so far met their obligation that they set themselves to increase the amount of market area storage that they have filled.

I've been watching those numbers, and they are above the number that they were at last year November 1. I expect they're going to be somewhat higher than that yet since the numbers I looked at were about a week old.

That's what happened in there, and the same thing with the other pipes. But, as I said earlier, these are complex mechanical systems and people systems.

NGPL is currently experiencing a force majeure outage. It is expected to continue through the end of October. What does that mean? It essentially means that, if I wanted to take a hundred percent of the gas supply through this one piece of pipe, I can't. It's cut already. We're expecting and hopefully it's going to be back by November 1st, but those units and that capacity is down today.

Scott talked about it a little bit in November where he said the Amarillo system was down 50 percent for two consecutive periods of time. NGPL is currently experiencing that today. It's a different part of the system, but it's there today.

CHAIRMAN SCOTT: What's the underlying problem that -- with the force majeure? I mean, I understand it in --

MR. DOBSON: In the winter?

CHAIRMAN SCOTT: -- in the winter. I'm missing it right now.

MR. DOBSON: I believe this was a -- as a result of the PHMSA or the pipeline maintenance folks. They found a spot in their pipe that they had to go in and dig out, and as a result, it needed to be replaced, and that takes some of the capacity down. They have to reduce the volume that will flow through that point so that they can make the mechanical repairs on the system.

In some senses, it's good it's happening in October rather than December. In many senses, it's good it's happening today rather than when it breaks and completely fouls up. And I'll talk to that in just a second because that's exactly what's going on with ANR.

ARN had a pipe in Michigan that quite simply broke and blew up. It has reduced the ability for ANR to serve the Benton Harbor area and is expected to continue for a little bit of time yet. Exactly timing, I don't know, but that was a pipe that literally broke.

With respect to the NGPL system, they could -- they still continue to provide the service. It's just not at the full rated level.

So while we are through the winter of '13-'14, the winter of '14-'15 has its challenges in and of itself. Some of those are going to be mechanical. Some of those are going to be weather related.

Peoples Gas was able to provide reliable service to our customers throughout winter '13-'14 in the face of unprecedented operating conditions. I've been in the industry and doing gas supply on and off since '92 when I came back to work for Peoples in Chicago here. I can honestly say this is the coldest winter I can remember. I can remember colder days. I can remember colder spurts. But I cannot remember five months colder than normal. I can remember more snow but not shoveling as many times. Those to me are -- as I look at it.

Now, when you look at it and say "unprecedented operating conditions," those are conditions where we have people out on the streets working, where we have people and dispatching them to the storage fields. We had people at the storage fields during the cold periods where they were spending the night out there. We had guys that were going out there the day ahead of time or five or six hours before the start of their shift because they were concerned about being able to get out there and do their jobs.

Based on current NYMEX prices, natural gas prices are expected to remain relatively stable. You heard that earlier. We're looking at prices between 4 and $6. Much of our hedge position and much of our storage gas is in that same range. Short of weather spiking pretty hard and driving prices even goofier than they can be, we're expecting to be fairly solid.

Finally, if weather's near normal, we are expect our costs will be at or below last year, but customers should still prepare for the cold weather.

Thank you for the time.

COMMISSIONER COLGAN: Questions?

Commissioner del Valle.

COMMISSIONER DEL VALLE: Earlier it was indicated that price delivery to residential customers will be higher in 2014-15 than in 2013 based on commodity price increases and fixed delivery cost increases, and you say that prices will be lower than last year.

MR. DOBSON: I believe that comment came from AGA, and they were talking about on a national basis.

COMMISSIONER DEL VALLE: So that's a national average.

MR. DOBSON: Yes. And ours are much more parochial.

COMMISSIONER DEL VALLE: Will that also be the case for Nicor?

MS. HOLMES: Yeah. The -- the price -- the NYMEX is higher this winter than it was last week. So if that's an indication of what the prices would do, that naturally would be a little higher, but as far as -- the weather's going to determine what the range would really be. So if the weather is better than what it was last year, for example, then we wouldn't expect the prices to spike quite as high.

COMMISSIONER DEL VALLE: Well, they won't spike quite as high, but will they be lower than --

MR. DOBSON: Commissioner, what I'd like to clarify, though, is while the pricing may be slightly higher, because we're expecting much more closer to normal weather, the total bill, total cost --

COMMISSIONER DEL VALLE: So you're talking about total costs.

MR. DOBSON: Yes. And I'm -- and from my perspective, I'm talking about the cost of the gas. So if you're consuming a hundred units at $5, if you consume 95 units at $5.10, you're going to see an overall price reduction.

COMMISSIONER DEL VALLE: So the price will be higher, but the total bill cost will be lower because of the weather.

MR. DOBSON: We're hoping that the price is less volatile than it was last year.

COMMISSIONER DEL VALLE: Well, I mean, I don't know what we can compare to last year. That was just -- I'm thinking about the year prior to that, I mean, when it was closer to normal; right?

MR. DOBSON: I can get back to you on that. I'll have one of the rates people get back to you on where we expect those costs --

COMMISSIONER DEL VALLE: Yeah. The reason I ask is because that's -- that's what's important.

MR. DOBSON: Sure. Overall, we think --

COMMISSIONER DEL VALLE: That's what we're talking about. Are we going to get hit with higher prices even though it is predicted that we're not going to experience another polar vortex?

MR. DOBSON: I am hopeful that the price I'm paying for gas, based on what we have already purchased, will be similar to the average price we are seeing today. That, overall, should be lower than what we saw for winter '13-'14 because we're going to take out those huge spikes. On average, it may be slightly higher because of the quantities, but the total consumption will be down.

You're asking me to parse a price

forecast, and I'm having challenges responding to you in a way that I think would make you happy. I don't think the prices are going to go crazy. I think we're going to see prices at the national level and in the Chicagoland area where we are around 4.50 to 5.50. As we convert that into the PGA rates, they will be lower than what they were last year because hopefully we won't have the lag that we had last year in the recoveries, and we won't see as much spot purchases at extremely high prices going forward.

But, overall, we are expecting, based on a closer to normal weather consumption, the total quantity on each bill to come down, and therefore the total bill on a month-to-month basis to be lower.

I'm not sure if that helped you, but it's the best I can do.

COMMISSIONER DEL VALLE: No. No. I followed you, but let's just pray for a good winter.

MR. DOBSON: I am.

COMMISSIONER COLGAN: All right. Our next speaker is Brian Wiese.

And I apologize. We're running a little over time here, but I hope you all can stick with us here for another ten minutes or so at least.

Brian is responsible for natural gas procurement at MidAmerican Energy Company. He's also responsible for hedging and optimization activities of regulated natural gas utility serving 700,000 customers in Iowa, South Dakota, Illinois, and Nebraska. Also, he's responsible for procuring and managing related transportation, storage, and other supporting services and assets.

He assumed his current position in July of 2012. He's employed by the MidAmerican Energy company since 1996 in a variety of finance and risk management positions, most recently as director of risk management from 2007 until assuming his current position which was in 2012.

Welcome, Mr. Wiese.

MR. WIESE: Thank you. Appreciate the opportunity to present this morning. I'll try to move quickly. We're, you know, last in line of presenters and with some of the many similar observations as we're all similarly situated.

On slide two, though, just some statistics on MidAmerican's Illinois system, and Illinois' system really isn't something we manage separately. We manage our Illinois customer base as part of a larger system where we serve a little over 700,000 customers in Iowa and South Dakota as well as Illinois. So we don't manage a separate portfolio, but we manage a part of an integrated system.

But you can see our peak day for winter 2014 was about an 11 percent increase over our prior peak day. Coincidently, January 6th was the day when we experienced the system peak as well.

Our Illinois customer base, which is largely the Illinois side of the Quad Cities, represented about 9 percent of our overall system peak on that day.

Another statistic: Our peak day for Illinois customers was around 96 percent of our estimated design day going into the winter. So we didn't hit the design day that we planned for, but we came mighty close.

And, interestingly enough, on our system as a whole, our peak day was around 97 percent of our design day, and that's on our sales customers, not our transportation, just on our sales customers. But we hit that on weather that was just under 90 percent of our theoretical design day weather. So we had some interesting observation on that. We saw customer load a bit higher than what we might have otherwise predicted, and that gives us some data points to work with going forward that I'll talk about.

But, again, it was challenging, but we met our peak requirement; and, again, it was below what we had planned for in terms of a design day.

Also, in this slide you can see the increase in our design day estimate for next year. For our Illinois customers, it's skewed a little bit by our -- what's on here as expected third-party deliveries or our transport customers. That's not necessarily as weather sensitive as our residential customer base, but we did a see a bit heavier pull by our transport customers.

So our overall design day increased -- our estimated increase for Illinois customers was up about 10.4 percent looking ahead to next winter. Our system as a whole, our design day estimate for sales requirements, is up about 3.5 percent based on reevaluation of the data that we got from last winter.

On the next slide, just a brief overview of how we -- you know, how we basically plan to supply our customers, and this plan hasn't changed. It's really a function of the assets that we have available. We're not blessed with the geology and geography of on-system storage like the other folks here at the stable. So we rely on contracted services for our storage and transportation.

We bring -- we serve our customers with around 90 percent firm transportation that we control, and we do similar to the other utilities: We roll it generally in three-year increments so that we have not all of our eggs in one basket.

About 50 to 55 percent is supply

purchases that we flow on transportation we control. About 30 to 35 percent is gas that we withdraw from our leased storage. We have about -- just under 17 Bcf of leased storage on three pipelines that we use to serve our customers.

And we are fortunate to have a bit of -- I'll call it on-system storage, but we have three liquefied natural gas peaking facilities on our system. In terms of our Illinois customers, we have one that's located in Bettendorf, Iowa, that supports our Quad Cities system primarily. Those assets were hugely beneficial to us this past winter, and we -- I'll get to it on the next slide how we utilized those facilities. They don't supply a big percentage of our peak load, but they really do supplement on intraday when we have peaking hours, when we have pressure issues. Those facilities really proved their worth the past winter.

And then, finally, we supplement with city-gate delivered supply, which is gas flowing on somebody else's transportation that they can drop off at our city gate. And, again, we benefit -- our system -- our Illinois customers are on the eastern edge of our system, but we benefit from being on that highway to Chicago with four major interstate pipelines that we can use to serve that part of our territory.

So in the next slide, again, just some highlights from our perspective on the past winter. Again, we set a new historical system peak on January 6th, but our previous historical peak was in January of 2009, but we had five days this past winter with system throughput that exceeded our past system peak.

We had -- you know, going back to December 2000, really when our companies combined into the utility that looks a little bit more similar to what we have today, we had -- we've had 47 days with system sendout out greater than a Bcf. 18 of those occurred in this past winter, and that's 38 percent in one winter. Going back a long way.

So some of that is a function of, you know, the relentless cold weather we saw; and I use "relentless" because it really came in waves, and certainly that played a role in it. But we also saw parts of our system tested by cold weather that have grown, and we knew they had been growing. We just hadn't seen it necessarily before. So it really brought out a lot of good data points really on our system. Our system as a whole performed fairly well, and that's not my doing as much as the folks in the field and the operation side of things. But, anyway, so really challenging year.

Again, our sales customer demand reached between 96 and 97 percent of our design day forecast but on weather system-wide that was only about 84 percent of design day. Again, parts of our system -- we have nine weather stations that we group customers into. Some of the weather was closer to what we would say would be peak day weather and others wasn't, but system-wide -- you know, the east side of our service territory was colder than the west, which is unusual. Normally cold weather on the northwest of our system is more of an emphasis.

Another observation: Again, record utilization of our on-system liquefied natural gas facilities. You know, we really hadn't vaporized much from those facilities over the past couple winters prior to that. This past winter we used them significantly -- part for system support when we had peak hour needs, when we had pressure support that we needed them for, but part simply for supply optimization. When we could, you know, look to the market and see north of $30 spot market gas and be able to vaporize out of the tank for an all-in-cost less than $6, if you will, maybe closer to $5, it made a lot of sense to use those assets. And they proved hugely valuable to our customers for that reason.

Over the past winter we had no firm customers that were interrupted due to lack of supply. We don't have any interruptible customers in Illinois. We have a handful in Iowa and South Dakota. Iowa -- a lot of them are more seasonal. They're crop driers, things like that, where the interruption really didn't have an impact. Some smaller interruptible customers that we did interrupt a number of times have dual-fuel capability, and we were able to work with them, but it's a very, very small component of our system-wide load; and, again, none in

Illinois.

And then we did -- we don't have third-party generation on our system. We have some gas-fired generation on our own electric utility side. We manage procurement -- gas procurement in a separate group for there to keep it separate from our PGA gas, but we do work with them to help them out when there's supply challenges, and certainly there were challenges. But I think we were able to navigate the conditions for our relatively small gas portfolio fairly well over the course of the winter.

Moving on to the next slide, more important -- you know, we survived last winter. Where do we go from here? And really the exercise looking ahead to next winter isn't much different from the exercise we go through every winter in terms of trying to adopt lessons learned and things we could do better to serve our customers, but we have a whole lot of data from the past winter to work with and some good lessons learned and things that we think found merit to do differently.

First off, out design day forecast.

Again, we incorporated, you know, the new data points in our statistical analysis and resulted in about a 3.5 percent increase system-wide in our sales forecast.

We've been actively engaged in dialogue with the pipelines and suppliers -- all of our pipelines and suppliers. I don't -- I won't regurgitate the comments from others, but we've been fully engaged with NGPL, with Northern Natural Gas, with ANR, with Northern Border, all of the pipelines that serve us. We learned last winter that we do rely on others to perform as agreed, and we can make the best plans that work perfectly on paper, but operationally, if folks don't perform, that throws a wrench in everything. And so we're acutely aware of that and been working with our vendors.

We have acquired some additional firm capacity on our system. We've done some realignment. We've done some supply portfolio alterations, again, in response to that increased demand we see based on our forecast.

We are on track to complete our own leased storage injections by November 1st. It's typical for us to fully cycle our storage. We typically use all the gas we have in storage every year and refill it in the off season. So from our standpoint, that's kind of a normal course of business. We have a supply plan. We have sufficient summer capacity to fill our storage. So we've been -- we're on track to get those inventories where we need them.

We're finishing up our fall liquefaction in our three liquefied natural gas facilities. You know, vaporizing is a lot easier than liquefying, and certainly our liquefaction runs have been a lot harder this fall than they've been prior. We have one facility that's maybe struggled a little bit more than others, and what we're doing there is supplementing with some additional delivered supply to take account of probably less inventory we'll have going into the winter, but we'll match that up with some supply and for this winter be able to be in decent shape on that.

And then, finally, our price hedging. You know, like the others, we hedge a portion of our winter supply, anticipate customer demand.

Our hedging will be completed by November 1st. In fact, it's almost done right now. We're finishing up some positions before the winter, and we'll have our hedging in place prior to the start of the winter.

In terms of price, again, we're -- I guess our experience tells us prices -- prices are low and stable. They tend to be that way until they're not. We're hoping for more of the same at least from what current forward prices are right now. We should -- you know, our PGA should be within range of where it was two years ago in a more normal winter. Again, weather, the fickleness of the market will ultimately dictate.

But the one observation -- you know, we tend to look at NYMEX, and the NYMEX natural gas contract -- it's the best indicator we have of national gas prices, but I think last winter reminded us all that it's really a local and regional game when it comes to price for our customers. And we're hoping that -- we're hoping that our pipelines -- we're hoping that our suppliers perform as agreed, and we're hoping that the plan that we have that we believe works well on paper comes to fruition at the close of the winter.

So with that, certainly happy to take any questions you might have.

COMMISSIONER COLGAN: Any questions for Mr. Wiese?

(No response.)

COMMISSIONER COLGAN: Okay.

Well, thank all of you a lot. All the presentations, I think, were right on the mark. I think you paid attention to the questions that we asked and your deliveries were addressing those issues. Thank you for the time to prepare and to travel to be here and to provide your comments to the Commission.

Any comments from any other Commissioners? No?

COMMISSIONER MAYE: I just wanted again to take the time to thank you, Commissioner Colgan, for putting this on. It was very informative and very beneficial, and it truly is necessary.

And, of course, want to thank Linda Wagner for her support.

CHAIRMAN SCOTT: Ditto.

COMMISSIONER COLGAN: Thank you, Linda.

With that, we're adjourned.

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