BEFORE THE
ILLINOIS COMMERCE COMMISSION

ELECTRIC AND GAS POLICY SESSION
2014 SUMMER PREPAREDNESS

Springfield and Chicago, Illinois
Wednesday, May 14, 2014

Met, pursuant to notice, at 10:00 a.m., May 14, 2014.

PRESENT:

MR. JOHN T. COLGAN, Commissioner
MS. ANN McCABE, Commissioner
MR. MIGUEL DEL VALLE, Commissioner
MS. SHERINA MAYE, Commissioner

Court Reporter:
Jennifer L. Crowe, CSR
Illinois CSR #084-003786
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PROCEEDINGS

COMMISSIONER COLGAN: My name is John Colgan. Pursuant to the provisions of the Illinois Open Meetings Act, I now convene this Electric and Gas Policy Session of the Illinois Commerce Commission to address 2014 summer preparedness. With me in Springfield is Commissioner Del Valle. In Chicago we have Commissioner McCabe and Commissioner Maye. We have a quorum.

I'd like to thank today's panelists for the effort they have put into the presentations and all of the participants for taking the time to attend today's Electric and Gas Policy Session.

Today our policy forum has a little deviation from the past summer preparedness meetings. As we are all aware, natural gas and gas pricing are no longer exclusively winter heating issues. With gas increasingly becoming a choice for electricity generation, it has equally become a summer issue.

There's been some discussion of concerns that natural gas storage has been depleted after the extreme weather of this past winter, and as a result of this depletion, given the demand for gas is now so high in the summer, it may not be a simple task to maintain proper inventory levels. I am sure everyone sees this as somewhat of a concerning issue. So I'm looking forward today to hearing about the manner in which utilities and RTO's will address this concern.

Since natural gas is expected to be relied on much more heavily in electricity generation, the interdependencies of these industries merits careful attention. As a result of that, on July 9th of this year, the ICC will hold a Gas and Electricity Policy Session in Chicago to explore the very complicated issues surrounding coordination between the natural gas and electricity industries and the impact of that coordination on reliability, the potential impact of that coordination on reliability in pricing in Illinois. So I hope you will mark your calendars for the afternoon of July 9th and plan to attend that important policy meeting. I will look forward to seeing all of you there at that time.

Now I would like to turn this session over to Commissioner McCabe to offer some comments and to introduce the first two panelists. Commissioner

McCabe?

COMMISSIONER McCABE: Thank you, Commissioner Colgan. Each spring and fall the Commission holds meetings on preparedness. As last year and other years demonstrate, we are subject to severe storms, unexpected warm spells such as last September and prolonged cold spells in the winter. It can be difficult to predict the weather and modeling is complex. Our utilities and RTO's strive to handle a variety of situations to ensure resiliency and reliability. Grid modernization, as we will hear today, is helping reduce outages and increase resiliency.

Alex Trebek and Geraldo Rivera renowned not necessarily philosophers but TV personalities have commented on Mother Nature. Trebek said if you can't be in awe of Mother Nature, there is something wrong with you. Rivera commented Mother Nature may be forgiving this year or next year, but eventually she is going to come around and whack you. You have got to be prepared, and Preparation is what we are going to hear about today. Utility and RTO reps will address issues and questions posed in the meeting agenda. Speakers, please keep in mind that your time allocation includes questions and answers which we will try to save for the end of each panel when we are transitioning from Chicago to Springfield. We may have a few minutes of video reconnecting, so we can use that time for questions as well. And again, presenters, please identify yourselves.

Our first panel will be on summer electricity preparedness by the utility Commonwealth Edison. We have Terry Donnelly, Executive Vice President and Chief Operating Officer and Cheryl Maletich, Vice President, Distribution System Operations. It will be followed by MidAmerican Energy Company on the phone, Barry Campbell, Vice President of Energy Supply Management; Joe Moore, Vice President, Energy Delivery; Brian Wiese, Director of Gas Portfolio Planning and Trading.

And then from Springfield we will have Ameren Illinois Company. The panel will include Jackie Voiles, Senior Director of Regulatory Affairs; Maureen Borkowski, Senior Vice President; Ron Pate, Senior Vice President, Operations and Technical Services; Stan Ogden, Vice President, Customer Service and Metering Operations.

So with that we will turn it over to Terry and Cheryl.

MR. DONNELLY: Thank you. Good morning, Commissioners. I'm Terry Donnelly, ComEd Executive Vice President and Chief Operating Officer, and with me is Cheryl Maletich, Vice President, Distribution System Operations.

I want to thank the Commissioners for conducting these hearings thereby communicating your perspective on the importance and criticality of the state's electric NTS infrastructure.

I will make some opening remarks on the first two slides and then turn it over to Cheryl for some additional details on our preparedness.

Just to make a couple of points about 2013, last year, it was our best reliability performance year on record. Our SAIFI year of frequency of outages with or without storms was a best on record, and our CAIDI, or duration, was favorable to the five year mean and was the second best on record.

We did have less storms than some prior years but still a fair amount of activity. We had

17 storms impacting 1.3 million customers. Historically we may have had about approximately 2 million customers interrupted by storms. There were some heavy rainfall storms, about seven inches of rain on the April 17th storm which resulted in some flooding issues and, of course, in November -- certainly not the summer -- we had four tornados touch down in our service territory and interrupted about 200,000 customers and a devastating impact to some of our communities.

Our peak load was just over 22,000 megawatts on July 18th. That is not our all-time peak which was in July of 2011 which was 23,753 megawatts.

The one thing I wanted to highlight, most proud is our safety performance. Our safety performance is measured by our OSHA recordable rates. The best we have had in the history of ComEd. We are most proud of our initiatives in the area of safety.

EIMA investments, we will summarize a couple of those points later in the presentation. Last year benefited over a million customers and avoided 300,000 customer interruptions on the various programs.

Our storm task force is in its third year, and we improved restoration times by 17% last year, and our customer complaints, reliability complaints are the lowest on record.

As we look ahead to the summer of 2014, simply put we are prepared. Our peak load, what we might call worst case scenario, a one in ten year weather, is 23,500 megawatts, and we have our demand response programs in place. We have completed all our summer maintenance. Our capacity works will all be done by June 1st.

We will highlight some of our storm task force improvements which is our third year of improvements in storm restoration. Also EIMA storm hardening work, resiliency work and reliability work continue delivering benefits, and we will also briefly touch on our drills and training in emergency preparedness, contingency plans, spare equipment all in place.

We mention the flooding last year. We have flood mitigation plans in place. Those are temporary with permanent plans underway, and then we will talk about a little bit about messaging with our mobile ap and our text messaging for outage communications which continues to increase.

I will, at this point, turn it over to Cheryl for the balance of the presentation and then Q & A.

MS. MALETICH: Thank you, Terry. I'm Cheryl Maletich, Vice President, Distribution System Operations for ComEd.

On slide 4 we indicate our, as Terry spoke about, peak load is projected at 23,500 megawatts for 2014 which is below our all-time peak that we did hit. We have no transmission constraints and generation retirements have been mitigated, which I will discuss further in a few slides. Our demand response estimates are about 1300 megawatts which is about 6% of our projected peak for the year.

From a capacity standpoint we are about 97% complete to date, and we do, as Terry mentioned, expect to be complete prior to June 1st. We will have no transmission facility or distribution substation projected over 100% and no distribution circuits projected over 105%.

Our 2014 reliability programs are all progressing well with our lightening enhancements, one --

COMMISSIONER COLGAN: Can you go back with lightening enhancements?

MS. MALETICH: Okay. For 2014 our reliability programs are progressing as expected including our lightning enhancement, our 1% circuits and our cycle trimming.

As of part of our smart substations we are installing transformer monitoring which we have seen a significant reduction in substation transformer failures from nine that we had in 2012 to only one that we had in 2013. So we are seeing benefits to that program as well.

Slide 6 talks about our EIMA investments, and these graphs indicate all of the programs that we currently have. The percent completions for the EIMA programs are from program inception in 2012 through March of 2014, and as of March 2014 we are about 37% complete with the program benefiting about 1.7 million customers. I will talk about a couple of those programs in more detail.

The next slide is around storm hardening. This is really looking at targeted areas. So we have engineering solutions which we are about 53% complete. It is really targeting areas for either overhead to underground solutions, spacer cable for heavily treed areas or even potentially reroutes or distribution automation. And with these solutions we are actually benefiting 227 municipalities.

The second part of our storm hardening is around our enhanced vegetation management. We are about 60% complete with that program with more than 120 municipalities affected, and this is really looking at more aggressive solutions to our tree trimming, tree removal, more aggressive tree trimming, and we have really had enhanced outreach to our customers both prior to either removal or trimming and afterwards as well. We have increased our investments by over 20% from 2011.

Slide 8 discusses a little more about our benefits of our IEMA program. So from a distribution automation standpoint we are actually benefiting about 60% of our current customer base based on the program's progression to date. Our mainline program we are seeing the best, the best we have ever had in a decade from a mainline underground fault perspective in 2013. So we are really starting to see that the enhancements that we are making are benefiting our customers.

From an underground residential cable program, although we have had the least amount of faults in only the last three years rather than the last decade, the average number of customers that are affected per fault has been our best on record in 2013. So we are targeting the largest segments of our poorest performers.

Storm hardening, I discussed previously really looking to reduce our long duration interruptions, and in our advanced metering infrastructure we're eliminating more than 280,000 manual reads.

Slide 9, from a capacity and reliability perspective, we have some significant projects that are going on. We have a new veterans substation that is going to be installed in Lockport and will be live June of 2014, and we have Plano and Lisle substation upgrades that also will be complete by June of 2014. We have hardened some of the 34kV sources that go into O'Hare Airport and reduce our overhead exposure. That was complete in March.

From a generation retirement preparedness, we have three key projects that are on the way or complete. We have a new Waukegan substation that's on track to complete by June of 2014. The Burnham-Taylor 345 circuit upgrades in place. It was as actually in place and in service in March, and we have a new static var compensator in Prospect Heights that contracts to be in service by June 2014.

This is really assuring that we have the infrastructure in place for either any retirements that have already occurred or that we anticipate may occur.

Slide 10, from emergency preparedness standpoint, there is really two items i would like to cover. One is around mutual assistance. We really partnered a lot in the last year to increase our ability to provide and to receive mutual assistance. We have partnered with the Edison Electric Institute (EEI) on a National Response Event which is really designed around some major catastrophe somewhere in the United States to ensure utilities will, can and will share resources among each other, something like Hurricane Sandy.

We have also added our mutual assistance groups that we have been incorporated with, and we have added SEE, which is Southeast Electric

Exchange. We are not only involved with mutual assistance groups in the Midwest, but we have expanded and have added mutual assistance groups that are in the southern and eastern parts of the state as well.

From storm response improvements, Terry mentioned our storm task force. We are in our third year in a row. This year we have really concentrated on seven main areas, and we have about 105 changes that we are making to our processes to really help improve.

I will talk about a couple key areas. Communication is one. So we really look a lot at our Joint Information Center and our Joint Operation Center process, improving to ensure that from a municipality's perspective we understand what their concerns and their priorities are as well as any of the critical customers that we have in the service territory to ensure that we are appropriately prioritizing those outages.

We have looked at improving a lot of the efficiencies, especially around our vegetation management crews and our material delivery during storms to ensure that we have everything available for the crews when they need it and they are ready to work from an efficiency standpoint. And we have actually instituted some technology improvements for management and tracking of our crew makeups as well.

Slide 11, I will say this slide really has two parts. One section is really, I will say to prepare for the big, bad events that none of us hope happen. The first is around a blackout restoration preparedness. What the blackout restoration really is if we had a cascading event across the states that eliminated all of our transmission system and our entire system went down. This really is the procedure and process how we would pick the system back up.

Every utility has a plan. We have drilled the plan every year. We actually partnered with PJM in a system-wide exercise this year, and we also did benchmarking with Sand Diego Gas & Electric who unfortunately did experience a blackout in 2011 to get lessons learned from them as well.

We are also partnering in the fall with the City of Chicago and many of the state agencies on a drill to enact a terrorist-type event. So we are actually going to partner with them for a not only the city OEMC, FBI, Department of Homeland Security but others as well to really mimic a terrorist-type event that would have an effect on some of our infrastructure, drill not only internally what our response would be, but the communication, the coordination with the state entities as well.

You will see additional drills that are noted on the slide. We do have drills across all of the Exelon utilities. So from Philadelphia, Baltimore, we actually have individuals there that can seamlessly come onto the ComEd system if we would need them in the event of a storm just like they would be ComEd personnel.

Slide 12 focuses little more around communicating to our customers from a readiness standpoint for the summer. We obviously will have additional CSR staff that will be available from a call center perspective, and we continue to have the technology that is available that we have discussed before, our mobile ap, texting and our outage map as well.

One other key point that we improved this year was our bill redesign. We actually utilize a crowd sourcing to create more user-friendly bill, and we have gotten some good feedback from that as well.

From a contingency plan perspective we do have multiple pieces of emergency equipment that are ready and available for the storm season. We have six mobile substations. There is a picture of one there. And these are really if we have a failure of one of our substation transformers, we can roll this mobile piece of equipment into the substation to maintain our contingencies.

We have multiple generators that we own and that are available through a vendor that we have a, we have a contract with. We have spare transformer fleet. You will note in the middle of this slide, as Terry mentioned, our substation flood mitigation plan. We did have the flooding issues in April. We do have temporary flood mitigation measures in place for our flood prone stations, and we have permanent flood mitigation that is in progress that will complete later in 2014 and into 2015.

MR. DONNELLY: Thank you, Cheryl. That concludes our presentation pending questions.

COMMISSIONER McCABE: We will move onto MidAmerican. Would you please announce who is speaking?

MR. CAMPBELL: Yes, this is Barry Campbell, Vice President, Energy Supply Management, MidAmerican Energy. Thank you for the opportunity to talk with you in the alliance and to participate through a conference call.

We have for an underlying on slide 2 our presentation we will talk initially about the demand and capability reserves. Joe Moore, Vice President of Energy Delivery will provide information on delivery and customer response issues, I will provide and document energy efficiency briefly and give a high-level summary of the gas electric challenges, and then we will be open to questions following that. Brian Wiese, Director of Gas Portfolio Planning, is also with us to help answer any questions of the gas portion as well as participate in the panel later in the conference.

So with that, we will start on slide 3. Our 2014 expected net peak demand is 4,575 megawatts under normal weather cases. Our extreme weather forecast is at 4,881. We have resources to manage that very adequately.

In 2013 our actual peak demand was at 4,659. That occurred August 28th. Kind of an unusual, little bit of an unusual day. We didn't actually have any load reductions or load control going out toward the end of the month at that particular time, but it still did not exceed our all-time peak which occurred in 2011, and that was at 4,752 megawatts in July at that time.

Moving onto slide 4, from a reserve perspective just to show how adequately we have this covered, from a 2014 perspective under normal weather conditions we have a capability of 18%, even under extreme weather conditions almost 11% reserve capability. The 2013 actual net peak demand we had about 16% during the peak. So we have been able to manage that accordingly.

On slide 5, from an available resource perspective, our net capability is approximately 5,400 megawatts. It is a mixture of coal, gas, nuclear, oil, wind and hydro. We have some jointly owned resources as integrated utility at this point. With Illinois we obviously manage the generation resources on a high end as part of the MISO regional transmission organization.

From the demand side management, we do have a totally integrated type system at 330 megawatts, 61 megawatts of direct load control, 270 megawatts of interruptible demand. We also have as backup 85 megawatts of generation designated as capacity recourses in MISO.

From slide 6, just to give an overall picture of where we are currently, we have gone back and shown some history back in 2005 actuals and as described earlier 2011 was our sort of peak situation. The last bar on slide 6 shows our 2014 forecasted normal 4,575 with a high of 4,881. So that shows, kind of gives us perspective of where we are, we are managing with items such as energy efficiency or other programs to manage the peak demand.

With that I will turn it over to Joe Moore.

MR. MOORE: All right. Good afternoon or good morning. Joe Moore, Vice President of Energy Delivery.

On the transmission system, again, similar to prior years. We expect our system to perform well. We have no more transmission facilities that will be loaded above our normal ratings at the system peak or even in the worst case summer peak. We have no transmission or substation, sub-transmission facilities expected to load above normal readings either for single contingency events on the system.

And then on operating we have operating procedures as well here for some certain double contingency events. For example, we may end up ultimately using some MISO congestion management tools, redispatching our transmission loading relief in those particular cases.

Slide 9, MidAmerican doesn't expect any limitations in serving our customers through the summer of 2014. We continue to experience on occasion significant west to east flows in our system, specifically at the Quad Cities and Galesburg flow gates. And we have -- we will use those to help us maintain overloading issues across the flow gates.

Moving to slide 10, Storm Preparedness and Emergency Response. We continue to monitor daily and extended forecasts for severe weather.

We hold pre-storm calls as each system approaches our system, working on additional on-call crews and standby crews, and remote contract resources get contacted in advance of those systems' approach to make sure that we are prepared and ready to respond upon any issues.

We do monitor the radar in our electric system operations on a 24 by 7 basis, and over the last year we have also added an emergency preparedness manager. We have also added a distribution control training coordinator to help us train our distribution operators in an efficient and effective restoration.

And we have also established six additional positions in the distribution operator classification to make sure we have got enough staff to help us in system restoration.

Slide 11, pending the magnitude of the impacts from storms, we do operate -- beyond our control center we have local and remote storm centers that we open and can dispatch field resources basically across our entire system in one particular area. We also have remote company field services folks and contract recourses that also get dispatched and moved within our system to respond. We also use wire watchers and wire clearing crews to make sure that we get after downed wire calls, and we are part of the Midwest mutual assistance, and we do call on our Berkshire Hathaway Energy resources across all of the other system platforms when we have more major events, and they have responded.

We also have status calls throughout various events. We hold them usually about every four hours or so to make sure we understand the progress and make sure we have got the appropriate resources and to talk about estimated restoration times to get that communicated out to the customers.

We also, after each storm, perform a lessons learned, basically getting all the personnel involved in that particular storm together and gathering up all of the lessons to make adjustments to policies and procedures, and that's been going well.

Slide 12 is related to outage communications. We use a host of different communication strategies, using radio and television advertising.

Social media has kind of been picking up quite a bit, trying to get information out and take care of customers' concerns via social media.

We also use earned media, safety news releases and live interviews that come from various events, and we do have some level of web communication related to safety tips and information out on our web page.

We just recently updated our Outage Watch web page on our home page for MidAmerican Energy. It's got a bunch of information now related to individual outage information so people can go out and see estimated times of restoration and whether the crews are en route or the status, you know, working, et cetera, et cetera.

We also provide who to call information, specifically during downed wire type events. We put out a lot of information related to who to call if you find one of those downed wires so we can get resources out there to either protect that wire or to get it put into a safe condition.

Moving to slide 13, vegetation management, we continue on our three-year trim cycle in the distribution system and continue our annual inspection and remediation program of our transmission system.

We do put out fall and spring bill inserts related to tree safety and make sure that the customers understand that they can call us if they have any particular issues so we can avoid people getting hurt.

And this last year in 2013, 17.7% of all Illinois customer outage minutes were tree-related. That excludes the major storm events. And the customer outage minutes due to trees were down about 10%, almost 11%, in 2013 compared to 2012. So the effectiveness in our tree trimming has been shown there in the numbers.

Slide 14, our NESC Corrective Action Plan, back in 2008 per the ICC Orders, MidAmerican initiated a four-year program to identify issues with the National Electric Safety Code guidelines. All of those inspections were completed in 2011 and all the issues on company-owned equipment were corrected by the end of 2012.

During those inspections we discovered about 7,000 instances that were attachment point issues on customer-owned electrical equipment were occurring that were in violation of NESC. We have just about 6700 of those completed at this point. We expect here by the end of 2014 to have all of those complete, and we continue to inspect our system distribution system on a four-year cycle.

With that I turn it back to Barry for energy efficiency.

MR. CAMPBELL: Thank you, Joe. Very Briefly on slide 16, with regard to our energy efficiency program we have got a new five-year program in place for Illinois that was approved January 1 of this year through 2018. Most costs are covered via efficiency energy adjustment clause now shown separately on the bill.

In 2013 we had refunded $2.3 million to customers on that bill. The total Illinois spending was about 3.5 million. The difference there is associated with energy efficiency education through training, school curriculum, other type programs that may not be directly customer related.

The Savings overall for Illinois was from a demand perspective was approximately 18 megawatts for electric demand and from a gas perspective 316 therms and during peak time of 2,600 therms. So that is certainly a big help to us overall.

Moving onto slide 18, from a gas electric challenges perspective, this is kind of the high level of this point. More details will be discussed later. Basically we managed this winter utilizing our coal and wind resources. Future years, though, we do believe we are going to be more dependant on gas as mentioned earlier. That means more reliance on infrastructure.

We will continue -- we have in place and will continue to maintain the firm pipeline capacity contracts that we have for the combined cycle generation we have in place. We do believe there is going to be increased storage injections required for the coming winters as this was so depleted, but we do have a clear plan in place to meet that as required for the winter time frame.

We do believe as more gas generation comes on the system, there may be interstate pipeline that's not necessarily LDC or local distribution companies, but I believe that will require additional interstate pipeline advancements.

And then so from a conclusion overall

summary perspective, on slide 19, basically from load capability our 2014 reserves are nearly 11% even under extreme weather conditions.

From a delivery and customer response, our transmission ratings, operating procedures and contingency planning are in place, and the vegetation management program is working.

Energy efficiency, we have a five-year plan in place as noted and the gas/electric challenges will be managed with firm pipeline contracts and increased storage injections.

That concludes MidAmerican Energy's presentation at this time. If you would like, we will take any questions.

COMMISSIONER McCABE: Thank you.

MR. CAMPBELL: Thank you.

COMMISSIONER McCABE: We will see how quickly we transition to Ameren in Springfield.

Any questions in the interim?

COMMISSIONER DEL VALLE: Yes.

COMMISSIONER McCABE: Go ahead, Commissioner.

COMMISSIONER DEL VALLE: Thank you, Commissioner.

Both ComEd and now MidAmerican have talked about improvements in their vegetation management program. I'd just like to know what is it that we are doing today that we weren't doing before?

COMMISSIONER McCABE: MidAmerican, do you want to start?

MR. MOORE: Yeah, MidAmerican can start. On our three-year trim cycle we have been working on expanding our trim distances and things like that to make sure that we have gotten plenty of clearance.

We have also, we have also been working on making sure that we don't have overhanging trees over the top of our facilities which tend to fall through in major weather events, and we have also been working on what we call hot spotting which is where we go out and take a look at the various circuits prior to the storm season even though they may not necessarily be on our three-year scheduled cycle, and we go after those and get those trimmed up.

We have noticed in some cases some of the -- when you get a very wet year, it will grow much, much faster than expected. So we make sure we trim those back, and I think those have been helpful.

Let me give you one statistic here. Back in 2009 and '10, about 6 to 7 million or 6 to 7 million customer outage interruption minutes were due to trees, and now we are down in the 2 to 3 million. So there's been quite a substantial improvement. So I think that the teams working on that have been effective at getting after what the issues are that are causing these outages.

COMMISSIONER DEL VALLE: Do the improvements include responses, increased responses to customer complaints, concerns regarding vegetation?

MR. MOORE: Yeah, for MidAmerican, Joe Moore. We do have a pretty aggressive program where we let folks know we are going to be in the area so they understand we are going to be there. So they are getting an opportunity to let us know if they have any concerns, and then when they do have an issue, if we are not in that area we do have crews in that area working pretty substantially. We tend to get on those within a 24-hour period. COMMISSIONER DEL VALLE: Thank you.

MR. DONNELLY: This is Terry Donnelly from

Commonwealth Edison. Just make a couple comments on our veg -- enhancements to our vegetation program.

I say it is mainly in two areas. One, we have increased investment targeted, we call it storm hardening. We have identified areas that historically may have had increased tree outages over the past several years, and what we have done is enhance tree clearing and enhance the standards in terms of getting the overhang and other clearances removed from what I would call predominantly TAPs area.

So we have seen pretty significant funding on what we call storm hardening which is more of an aggressive focus on additional clearances and removal which is my second point.

The one area we are working on is to have more aggressive tree removal program in our fixed price cycle contracts. What we have done is we represent about 19% of the total trees addressed through our trimming program is now removals, and this helps us over the long run with removals. In 2000 -- previously historical rates were maybe 2% if you go way back. So we are up to about 20%

in the removal area of trees which helps us year over year.

We are absolutely 100% in compliance with the 48-month cycle trimming plan, but the enhancements are mainly on the storm hardening work targeting specific areas which is enhanced clearances and the removal, more aggressive focus on the tree removal program.

The additional question on customer complaints, a lot of our efforts focused specifically on developing better materials and outreach before we trim in an area and then proactively going back to customers after we trim in an area. So pre and post with some better materials and outreach is how we are working the customer issue of tree trimming.

COMMISSIONER COLGAN: All right. Thank you.

COMMISSIONER McCABE: Thank you. All right. Moving onto Ameren, the third panelist on the first panel.

MS. VOILES: Yes. Good morning. This is Jackie Voiles, Senior Director of Regulatory Affairs for Ameren Illinois. We are pleased to be here this morning to share information with the

Commissioners concerning how we prepare to serve our customers safely and reliable service not only this summer, but that's our goal to make sure that we continue to provide that service to our customers.

We are going to talk about several things today including the transmission resource adequacy. We are going to talk about our readiness plan from a transmission and distribution perspective, our emergency preparedness and response and our contact centers and communication strategy.

Ameren Illinois serves 1.2 million customers, electric customers in the state. We have a significant service territory throughout the state, and we serve 812,000 natural gas customers as well.

Probably the main message that we want to relay to you today is that we are prepared to serve our customers reliably this summer. We have the generation resources that are committed to serve the Illinois load. We have the transmission and distribution capacity as well.

Our expected peak loads for this summer are 7,553 megawatts. Worst case scenario, that's the worst in ten years, 8,129 megawatts for the summer. The 2013 expected peak was at 7,873 megawatts. We had a mild summer last year. We also had a large industrial expansion that postponed their expansion plans until this year. So we did see our actual at 7,234 megawatts compared to the expected peak.

From a capacity requirements perspective, the MISO capacity auction, we are seeing the clearing prices substantially increase year after year. In the 2013 2014, period the capacity prices were a dollar five a megawatt day, and the 2014 2015 period $16.75 a megawatt day. So we are seeing those prices increase from a capacity perspective that is going to send the right price signal to entities that are looking to build generation.

The MISO reserve requirement for 2014 is 14.8%, and that is based on installed capacity, but after accounting for load diversity, load diversity includes the fact that different utilities peak at different times, and when you take into account the forced outage history, the resource -- I'm sorry, the reserve requirement is 7.3%.

This slide shows who is going to supply the load to the Ameren Illinois customers. The fixed price load for the summer peak 1404 megawatts, the real time price load 376 megawatts, and that's for Ameren Illinois Company serving that supply. The retail electric supplier load, 5,773 megawatts for a total of the 7,553 megawatts. That is our expected peak for this summer.

In the forecast it does show a small increase in customers moving to third-party suppliers but not to the extent that we had previously seen. So it is pretty much flat compared to previous years.

This particular slide shows our forecasted supply portfolio for the Ameren supply. It shows what our peak load is for the fixed price and real time price load and then the capacity associated with that expected peak load.

So what you do is you take the anticipated peak load, you gross it up for the MISO reserve requirement of the 7.3% to come up with your capacity figures. That is rounded to the nearest 10 megawatts.

We want to talk on slide 9 about the demand response resources. There is interruptible load that's been identified. This is interruptible load through the retail electric suppliers, and that is significantly increased over the previous year.

Then from a real time pricing perspective for our residential, small C & I and our large customers greater than 150 kW, we do have the hourly day ahead MISO prices that are posted. We settle on that hourly day ahead MISO price. Customers are required to have interval metering installed in Orders to participate in those programs, and I've listed on this slide the megawatts and the account for those particular real time pricing products.

From a distributed generation and net metering perspective, we have an easy, simple process for our customers to connect distributed generation as well as participate in the net metering program. These figures on the top part of this slide under distributed generation include information beginning April 1 of 2008 when the Commission put into place the standardized interconnect rules. And then the net metering statistics, those are the current numbers that we have with regard to customers taking net metering.

I'm going to turn it over to Maureen Borkowski to talk about the transmission system.

MS. BORKOWSKI: Thank you, Jackie. As Jackie said, I'm Maureen Borkowski. I'm the Senior Vice President of Transmission for Ameren Services. I'm here to talk about our transmission system readiness.

First of all, we do not expect any constraints on the transmission system for Ameren Illinois that would inhibit any supplies by the retail electric suppliers to their customers in our service territory.

We have also ensured, as Jackie already mentioned, that those retail electric suppliers do have adequate resources to serve their load. We actually provide the forecast data to the retail electric suppliers so they do understand exactly how much load they are responsible for and then verify that they have those adequate resources.

Ameren Illinois' transmission system has just under 4600 circuit miles and 174 substations. None of those transmission facilities are anticipated to be above 100% of their rated capability at either the expected load case or the worst case load which is basically the 90/10 weather forecast. So we are in compliance with all NERC and SERC planning standards and that 100% is met even under all single contingency conditions.

We also participate in a summer operating study both with MISO and with SERC, and in all instances we were found to have our system be adequate to meet the summer loads.

To the extent that there on a real-time operating condition basis any constraints that would happen to occur, MISO has a congestion management process, and it would address those constraints on a real-time basis.

The next slide basically shows some of the new and upgraded facilities that have been placed in service or are about to be placed in service for this summer. This has been obviously since the last calendar year we were here.

There are a number of different line upgrades. Those generally involve reconductors to raise the rating on those facilities.

At the substations, most of those substations involve breaker replacements. The Gilman substation is not yet in service. It is scheduled for the new breakers. They are scheduled to go in service on June the 5th. The Latham substation was actually just placed in service last Tuesday. That, the substation work involved three 345 kV breakers and a ring bust, but that's actually the completion of a much bigger Latham Oreana project that involved nine miles of new transmission plus work at two substations, Latham and Oreana. It was actually completed ahead of schedule. So that completes that entire project.

We are going to be installing in June capacitor bank at the Fargo substation. That's a 40 megabar capacitor bank that's intended to improve the voltage in the Peoria area.

One other thing that's not on this slide but I thought you might have some curiosity about is we do have three major transmission projects that are underway that have already received certificates from the Commission for Ameren Illinois. That's the South Livingston Brokaw Line, the Bondville Southwest Campus and the Fargo Maple Ridge, and all of those are on schedule to be completed, the first two in 2015 and the second in -- third, excuse me, in 2016.

We also obviously have a comprehensive transmission vegetation management program. We are in complete compliance with the NERC standards, but we, too, have kind of upped our game in the transmission area much like ComEd had expressed. We, too, are trying to focus on tree removal rather than just tree trimming. So to the extent that our easements allow, we are trying to get back and remove trees to avoid the problems with continuously going back to trim and the potential that, you know, something could happen that would be unanticipated in terms of the rate of tree growth or what have you.

Our vegetation management group does have a basically target zero for no preventable tree outages, and certainly in 2013 we did comply with that performance objective. So we do focus on this heavily. Obviously at the transmission level, any kind of transmission outage could have consequences for customers and the system. So that's a high priority.

From a communication standpoint we do have a specific area of the Ameren web site for transmission vegetation management that explains to customers where exactly, what our rules are, what kind of vegetation is permitted. We also do door hangers, that kind of thing to notify customers when we are going to be in the area.

So that completes my report on the readiness of the transmission system. I will turn it over to Ron Pate.

MR. PATE: Thanks, Maureen. I am Ron Pate, Senior Vice President of Operations and Technical Services.

Maureen touched on the transmission. I'd like to take just a moment to talk about reliability on our distribution system. As you can see from this slide, all sub-transmission and distribution feeders as well as substations are expected to be loaded within ratings for expected summer conditions except for the few that I have noted here. On those work is either underway or being planned to alleviate those areas of concern.

Under worst case summer loading three additional substation transformers would exceed the ratings. One of those is a larger retail customer that we are working closely with to develop an upgrade plan with them. Another substation transformer is being replaced, and one more will be monitored to make sure that it is needed and a plan put in place for that.

So in summary, projects are identified and a plan to reduce the loadings below 100% for all but five of the locations and we will continue to monitor those locations, see if we need an upgraded plan on those as well.

Some of the projects associated with the Energy Infrastructure and Modernization Act are listed here. A couple that I will mention are Viper reclosers reduces the number of customers out by allowing operation on a single phase as opposed to all three phases. Also allows remote access so that we don't have to deal with the older type switches.

When we talk about the underground cable, of course, we prioritize our underground cable projects using criteria such as past failures, age, type of cable like that, prioritize those, get those replaced before we actually see the failure on those cables. So we will be able to advance that.

We also have a large reconductor project to increase capacity, and we have many distribution automation projects to reduce the number of customers impacted by routing around the fault.

These are IntelliRupters, and just to give you an example there of the improved reliability, we actually realized a customer interruption reduction last year of over 9,500 customers that would have been impacted had these not been in place. That related to almost 2 million customer minutes that we were able to avoid. Again, these IntelliRupters are able to route around a fault and reduce that number of customer outages.

As far as vegetation management, we continue to meet all legal and regulatory requirements. We are maintaining a four-year trim cycle. We try to keep about a two-week cushion on that as well in case we are called off on storms or to help in other areas.

And one of the questions that you had, Commissioner, about the enhancements, again, one of the things that I think has really improved ours is mid-year cycle that you have heard talked about. You know, go back where there's been fast growing species in trees on those circuits and go back that really may not be able to make it a full four years, and mid-cycle we go back, trim those as well as a lot more aggressive removal and overhang that you have heard other utilities talk about and Maureen as well.

You can see up here it has had a very positive impact on reliability. We see our tree-related SAIFI drop from within .16 in 2009 to .09 in 2013. So showing some very good benefits there. And we continue with our Right Tree Right Place program through ads that we may have, making people, the public aware that that's available to them.

And one thing we have really done as well is enhance that communication with those local municipalities. You heard Terry from ComEd talk about that communication beforehand and afterwards. We are doing the same thing with that as well, and that provides big benefits to have our supervisor right there with the municipalities and build a good relationship with those folks.

We also have some ongoing programs to help continue to improve our reliability as you can see up here. Early identification of worst-performing circuits and repair work is one of them showing very good improvement on eliminating future outages as well as our circuit inspection programs and device inspection programs.

Also customers exceeding reliability targets, or CERTs as we call them, is defined as customers that exceeded reliability targets for three consecutive years. In Orders to be proactive with that, we have actually taken that now and reduced that so we are tracking at the two-year interval so we don't get into that third year so we don't have customers show up on that CERT list.

To give you an example of that, this year so far we have had one that would be identified as three because we have gone ahead, been doing this for the last couple of years as far as getting two years, making those repairs as we go forward.

COMMISSIONER McCABE: Mr. Pate, if you could wrap up in a minute or so.

MR. PATE: I certainly can. This slide is pretty self-explanatory. Just shows you some of the work we're doing in the dispatch offices. The guidelines have been covered, the outage requests and work completed for this summer's loading conditions.

And the last slide that I have, no matter how much planning you do, Mother Nature will take over at some point. Our focus here is to make sure, when it does hit us, that we are taking action to get our restoration activities underway and completed as safely and efficiently as possible.

We have extensive training in all areas across all of our divisions and dispatch centers throughout the year. You can see the number of events we had in '13 and that we have had to activate the emergency operating center. This year we have had six so far with five of those being storm related. One was a gas event.

I might just take a second to brag here to mention that we did receive an EEI award for response to the November 17, 2013, storm response. We had tornadoes come through. Really devastated several of our communities, Washington, Gifford. Both of those come to mind. We had about 150,000 customers out there, restored 70% of those in the first 24 hours and had it completely cleaned up in 72 hours, and that recognition was there.

I will turn it over to Stan to talk about contact centers.

MR. OGDEN: I can certainly accommodate and go through my slides rather briefly here. My name is Stan Ogden. I'm Vice President of Customer Service and Metering Operations for Ameren Illinois.

The next slide really gives you the integrated approach that we take in responding to storms and responding to customer events. The integrated approach includes contact center operations, the community relations folks as well as the field operations team. We have incorporated outreaching communities when we have major storm events. The November 17th tornados are an example of that. We have mobilized people to be available in the community.

Internet and mobile social media is another avenue that we have as outreach, and we have 24-hour coverage with media to stay on top of storm and storm events.

We do have municipal education and safety training that we do throughout our service territory.

The next two slides I will just leave you as reference. These are the Senate Bill 1652 customer assistance programs, and they also include programs that we have had for many, many years, things like the Warm Neighbors Cool Friends program, we have our ActOnEnergy energy efficiency programs as well. The allocation of those dollars to the various programs assists our custom throughout the service territory.

I will just comment on slide 24. We did, because of the polar vortex event that we had this year with the extremely cold winter heating season, we did a community outreach in East St. Louis to reach customers who were having difficulties paying their bills. We also did statewide media around outreach and efforts to get to customers and helping them before the April 1st season, and those proved very beneficial.

In the case of East St. Louis, we had about 500 customers participated. We responded to 300 arrangements that day and 200 follow-up calls the next day.

Slide 25 recaps our energy efficiency activities. We are completing the sixth year of our energy efficiency programs. There you can see the savings as well as some of the carbon reductions that are accomplished affiliated with our energy efficiency programs.

Slide 26 does, again, discuss outreach. Again, one of the more effective outreaches that we have done is taking curriculum to the schools. This past spring we did take outreach to the schools, and this year it is near energy efficiency, next year it will be safety.

I will just comment that I think with some of the smart grid activities that the Illinois Science and Energy Innovation Foundation will be looking at outreach in the area of smart grid in the future as well, so I'm encouraged by that.

I will just point out to you that we have given you a packet today, and I think those of you in Chicago may have gotten this electronically. We do have hard copies available. Some of the activities and some of the outreach and customer communications that we have.

Finally to summarize the last slide, Ameren Illinois, as we have explained today has acquired generation capacity, and we have the transmission distribution capacity to provide reliable service customers expect for the 2014 season.

We are also working to complete critical maintenance items throughout our service territory. We have made improvements, and we continue to enhance our emergency preparedness, our response and our communication with our customers.

So with that I will conclude our presentation, ask if there are any questions.

COMMISSIONER McCABE: Any questions for the panel?

COMMISSIONER COLGAN: I do have one. I do have one question. And I appreciate your efforts to stay on time with your comments. I know there is a lot that you can talk about, and we can probably talk to each one of your utilities for the whole period about a lot of the issues that you'd like to discuss with us and that we'd like to hear from you.

But the one question that I have was on load forecasting. I notice that I think ComEd is a little down in their load forecast and MidAmerican is a little down and Ameren is a little bit up in your load forecast.

I was wondering if maybe I can get one or two of you to comment just a little bit about what the process is that you go through for trying to determine that load forecast.

MS. VOILES: Well, if I can just comment quickly. Our expected peak for 2013 was 7,873 megawatts, and our expected peak for the 2014 summer period is down from that figure.

COMMISSIONER COLGAN: Okay.

MS. VOILES: Down to 7,553 megawatts. So ours is down compared to last year's forecast as well.

COMMISSIONER COLGAN: Okay. How do you come about that number?

MS. BORKOWSKI: This really is not in my transmission hat area, but I actually used to do this for the company, so that's why I feel comfortable speaking to it.

It is really done at the corporate level where there is both economic and more customer specific. So top down kind of economic thing and bottom up where there are all kinds of econometric models that are in use to project individual sales volumes and individual, how that would feed, then, into the overall demand.

So it is done at multiple, multiple layers and assembled up, but that it is also looked at on an aggregate forecast for the entire state, and, again, we are looking at the system peak number represents not only Ameren Illinois' peak demand but also includes all of the retail electric supplier demand as well.

So really it is looking at the forecast for the economy as well as recent history. It is always done on a normal weather basis, and then we do look for known changes. ADM is adding load for example. So you do look for known large changes, take into account energy efficiency programs. That's kind of one of the modifications.

So that is how that works, and, you know, really that's basically how it is. It is an econometric type model, but it also uses a bottom up approach. They look at the sales growth and how that relates to peak demand growth over time, and they are not one for one. Usually the actual sales volume usually tends to grow faster than the peak demand volume, especially now that we have peak reducing efforts in place. So --

COMMISSIONER COLGAN: Right. Okay.

MS. BORKOWSKI: Pretty broad analysis.

COMMISSIONER COLGAN: All right.

MR. DONNELLY: Terry Donnelly from ComEd. Very similar econometric models just as it was stated. Also we work with PJM, the interconnection make sure there is alignment around the load forecasting across the interconnection. We tie our local models, econometric models with PJM to make sure we have the right forecast.

Our 90/10 forecast which is one in ten year weather, we call that worst case. That is slightly below about 200 megawatts, our all-time peak in July 2011 which we heard a lot of the companies, that's when they hit their peak. Actually that year was, I think, actually worse than the one in ten, one in ten year weather. So it was probably a little bit higher than even the worst case but very similar to what was reported in terms of how we go about coming up with the forecast.

COMMISSIONER COLGAN: Okay. Thank you.

MR. CAMPBELL: This is Barry Campbell, MidAmerican Energy. We also very similar econometric, but we also depend very much on our managers and individual customer information to bring it up, and we also perform probabilistic-type approach as to what could happen. Just bear in mind the history and actuals includes weather, so you may see some impacts from the severe weather or hotter weather than normal, but as going forward we forecast for a normal weather basis and allow as in our slides, the normal case above hand.

COMMISSIONER DEL VALLE: Just a follow-up question. Ameren described their method and then MidAmerican and ComEd said we have similar, similar methods. Why are there variations at all?

MR. CAMPBELL: May have to do --

COURT REPORTER: Sir, can you identify yourself, please? Sir?

MR. CAMPBELL: And so we may have the modeling that we actually use or type of model that is actually used may be different, but when we say similar, we mean the methodology is similar, and we may just differ on what the drivers are, and that would be dependent on the service territory.

COMMISSIONER DEL VALLE: So the methodology is pretty much the same, but drivers can vary?

MR. CAMPBELL: Correct.

COMMISSIONER COLGAN: Can you identify yourself for the court reporter?

MR. CAMPBELL: I'm sorry. This is Barry Campbell with MidAmerican.

COMMISSIONER McCABE: I want to thank you. I think there is a lot of work and investment going on and learning from prior years.

We will move onto the RTO panel. With us in Springfield will be Joe Gardner, Vice President of Forward Markets and Operations Services with MISO. And here in Chicago will be Rich Mathias, Senior Consultant, PJM Interconnection.

Mr. GARDNER: Okay. Good morning. My name is Joe Gardner, Vice President of Forward Markets and Operations Services with MISO. Pleased to be here today to talk about MISO's preparedness for the summer.

We do -- I should wait until the slides are up.

Okay. All right. We do project adequate reserves from the 2014 summer peak demand on a footprint wide basis as well as in the central and north regions. We do have a reduced reserve requirement that I will talk in more detail about later in the presentation. It does reflect a tighter supply due to several factors including retirements that will, potentially cause us to have to call on our emergency only resources more often than we have had to in the past.

We will continue to work with our neighbors and try to eliminate barriers and inefficiencies across seams and further optimize those efforts, and the outlook beyond the summer is a further reduction of reserves. I will talk a little bit more about that later in the presentation.

In addition we are exploring the feasibility of establishing a seasonal resource adequacy model to reflect the difference between summer and winter in particular.

Next slide, as we have talked about I think in many different forms, the generation fleet in MISO overall is being affected by various factors. For example, the mercury and air toxin standards that are going into effect in compliant states are 2015 and 2016. That is causing coal retirements to occur. It is causing us to have to evaluate how we look at outages, how we plan for outages, the timing of those outages. It is resulting in shrinking reserve margins in our footprint, and it is causing, as was noted earlier by the Commissioner, a growing dependency on natural gas in the footprint.

We are looking forward to the carbon regulations that are going to be coming out in a month or so and working with our states in our jurisdictions as well as all of our utilities on that draft rule to see how it may affect us going forward.

Next slide. So as I indicated the projected reserves for our summer speak are 15% on an overall footprint basis including the south region. I will talk a little bit more about your central and north in a second. Our reserve margin target for the summer is 14.8. So we do have a little bit of extra above the required target which is a required target that gives us a one day in ten year standard for drop in a firm load.

The reserve requirement is higher due to both fleet performance and reduced neighboring reserve margins. So as we look across the footprint and as reserve margins change everywhere, we can count on less imports from our neighbors as well. So we do reflect that in the forecast in the planning reserve requirement as well.

Next slide. So our previous planning reserve margin from last year was 14.2% due to a slight reduction in generation fleet performance and the imports that I just talked about. We did increase the planning reserve margin target for 2014 by .6%.

We do have a diversity benefit our utilities enjoy as a result of being MISO where the loads do not peak all at the same time, and so the average requirement on an ongoing peak basis for our utilities is 7.9%.

Next slide. The reserve margins are tightening. The slide just gives a little color associated with what happened. This is just the north and central region. The 2013 reserves we had reported were 25.7 gigawatts. Due to requirements we have had 3.1 gigawatt reduction, and when we remove non-firm imports that I talked about and adjusted for those things, we had a reduction of 4 1/2 gigawatts. We did increase the amount that we can expect to import from the south region into the north and central by one gigawatt resulting in 2014 reserve margin of 19.1 gigawatts for the summer for the north and central regions.

The 2016 resource adequacy forecast, I'm not going to go into a lot of detail on this. This was as of January 31st. It did show expected shortfall of the north and central regions of 2 gigawatts and in the south region a surplus of 5 1/2 gigawatts. We are in the process of working with our members on all of these numbers and expect to release an updated value during the first week of June.

And then finally we continue to evaluate potential solutions. We do have some generation that may be trapped behind transmission in various parts of the footprint. We are working at various solutions to try and untrap that stranded capacity. We continue to work with our members to refine our processes and allow them to offer in, in different ways, their load modifying resources which includes your demand response programs as well as behind the meter generation.

We continue to work with our neighbors on both energy and capacity transactions that can flow across our seams, and as I mentioned we're evaluating the seasonal nature as issues associated with natural gas in particular and working with the gas and electric issues that FERC has recently issued on as well.

With that I will be glad to take any questions.

COMMISSIONER McCABE: Any questions? If not, Joe, stay at the table. We will have Richard Mathias, then see if there is questions for both of you.

MR. GARDNER: Okay.

MR. MATHIAS: Good morning. My name is Rich Mathias. I represent PJM Interconnection which is a regional transmission organization which operates in parts of all of 13 states and the District of Columbia. In Illinois PJM manages the transmission assets which are owned by Commonwealth Edison.

Just as the other speakers this morning have stated, PJM believes it has sufficient committed resources and transmission system availability to meet the forecast peak load and reserve margin in Illinois and in the PJM footprint. If, by some unusual circumstances, PJM experiences abnormal availability and/or unusual weather conditions, PJM may undertake emergency procedures as necessary.

I brought along five slides today to recap very briefly the summer preparedness of PJM. Slides 2 and 3 show basically the reserve margin and the capability of PJM to meet the forecasted summer peak load for 2014 and makes a comparison to 2013 as well.

I note EKPC, an Eastern Kentucky company that became a member of PJM in 2013, and their numbers were added to this chart that is slide number 2. We note that PJM will have a reserve margin of 25.4% footprint wide and is against a required reserve margin of 16.2%.

Just like the representative from Midwest, you will see that the PJM required reserve margin increased, and that's due to as well to the three performers within PJM.

As far as forecast mode, the answer to Commissioner Colgan's inquiry, PJM does its own load forecast. It does it with, in cooperation with the members of PJM which include ComEd. The numbers that are indicated on slide 2, the load forecast of 157,000 megawatts is the so-called 50/50 load forecast that we anticipate going forward.

I would note that PJM is anticipating only a 1% load growth over the next ten years. Only a 1% load growth which is quite a change from prior years when you used to just say automatically going to be a 2 or 3% increase in load growth, but there are a number of factors which are to come into play with regard to that.

I would note also with regard to the upcoming summers of 2015, 2016 and 2017, we are very concerned about retirements of generation in the PJM system. We, as you know several months ago in 2011, we forecast as 25,000 megawatts of retirements of generation in the PJM footprint. Quite frankly we are seeing we are very close to the top end of that. Nonetheless we will have sufficient resources in the upcoming 2015, 2016 and 2017 years to ensure sufficiency of meeting the load and the hidden reserve requirement. Due to the reliability of pricing model, so-called PJM capacity construct, we have already acquired sufficient capacity for those three out years.

Others have talked about the concerns and challenges of the past winter, the so-called polar vortex, and the next two slides really are aimed at highlighting some of the challenges and some of the responses that PJM and others have had with regard to these very unusual loads in the winter as well as in the summertime going forward. We wonder if we don't have a new normal.

As a result of the performance of our generators and others within the PJM fleet, we are undertaking these new and more aggressive challenges going forward, and many of these are outlined in the summer report or, excuse me, winter vortex report which was just released yesterday by PJM Interconnection. I am sure that Joe Gardner would agree that many of these are the same types of initiatives that are underway within the Midwest ISO.

I believe the bullets are self-explanatory. One I would note, though, is with regard to the load forecasting improvements. That's not necessarily a load forecasting improvement for the month or for the year, it is really the day ahead load forecasting improvements.

We did not do as good a job as we would have liked to have done in January and February and March in forecasting a day ahead manner, the forecast for the coming day, and as a result we had to really scramble to make certain that we had enough assets, generation assets and demand response and other items to meet the very, very increased load.

Just like the Midwest ISO, eight of the ten largest, highest peaks in the winter in the past many years were experienced this January. Eight of the ten highest peaks in PJM history for winter operations were experienced in January. Some days we were at 35,000 megawatts higher than the normal load for that day. 35,000 megawatts is equal to what the City of Chicago or Philadelphia and Washington DC would require for their normal winter operations.

I note that at the end of the bullets here there is a bullet concerning gas electric coordination, and I really think this slide, the final slide, number 5, to be a segue for the Commission's discussion of gas electric coordination.

You can see why PJM and others in the PJM footprint as well as the Midwest ISO are very interested in natural gas coordination with assuring that gas is available when it is needed both in the summertime and in the wintertime to drive the generation assets which are in the Midwest ISO and PJM.

As you look at this pie chart you can see the number of megawatts of the wind PJM has. The Midwest ISO would have considerable more, probably twice as much as far as wind assets. There are around 13 to 14,000 named wind assets. If you look at the natural gas generation assets, PJM would be significantly ahead of the number that Midwest ISO has.

But again, when you have got 53,000 megawatts, 53,000 megawatts of natural gas generating capacity in PJM, you want to make certain that as many of those megawatts are available in the summer and winter as possibly that they can be.

We would note that this past January in the winter vortex that we had a very high outage rate within PJM. Almost 20% percent of our total megawatts were out, and about a quarter of that 20% was from inability for the natural gas generators to obtain natural gas supply. So when you are discussing later on this morning, we will be taking notes and be very interested in what is said during that time.

But again, PJM believes it has adequate resources to meet the forecast load and the reserve margins for the upcoming summer, and we will also -- I believe we have sufficient generation assets and demand response and energy efficiency resources to meet a much higher load as well.

COMMISSIONER McCABE: Rich, your last point on dependence on natural gas, which will probably increase with retirement and environmental compliance, I'd be interested in both PJM and MISO's thoughts on how this area compares to the east which seems even more constrained and if we might be in a better place.

MR. MATHIAS: Joe, do you want to lead off?

MR. GARDNER: I think -- you know, I will be glad to. I think we are in a better place than in particular New England which has a relatively limited supply of pipes into that area. We do have many, many pipelines cross our footprint.

Having said that, we do expect to continue to increase our use of natural gas, and we will start utilizing those pipes to a fuller extent than we have in the past which will put an increased demand on that, which is one of the reasons why we are looking at things like doing a seasonal construct to ensure that -- one of the thoughts there is to ensure that resources in the winter do have adequate supply.

So I think we are in a better spot than the northeast, but we will continue to increase our utilization.

MR. MATHIAS: I would agree with what Joe just mentioned. I would also indicate that in the polar vortex, beginning of the polar vortex when people at PJM were talking with the gas pipelines, number one, we couldn't talk with them and share confidential information until FERC issued an emergency Orders that allowed such confidential communications.

And then secondly, just the terminology that was being used by electric generators, PJM, and others in the electric generation and transmission business, the terminology was totally different from what was being used by the natural gas pipelines and the natural gas companies such as

Peoples. So if we learned one thing during the past winter, we have learned how to talk the other guys' language.

COMMISSIONER McCABE: Other questions?

Okay. Thank you both, Rich Mathias from PJM and Joe Gardner with MISO.

And Commissioner Colgan, are you willing to just continue?

COMMISSIONER COLGAN: Okay. Our final panel, our final panel this morning consists of discussion regarding the issues and challenges of natural gas availability related to winter use. The panelists for this segment of our forum today will be Tim Sherwood who is Vice President, Gas and Supply Operations at Nicor Gas; Rich Dobson, Manager of Gas Supply for Peoples Gas, and Scott Glaeser, Vice President, Gas Operations & Development at Ameren Illinois Company.

So if you gentlemen would like to come forward.

UNIDENTIFIED: Who is up first?

COMMISSIONER COLGAN: First we will go with Nicor.

MR. SHERWOOD: Good morning. Yeah, my name is Tim Sherwood. I'm the Vice President of Gas Supply Operations for Nicor Gas. I'm going to address some of the issues that were asked in the agenda from the Commission. First I'm going to review quickly what our experience was this past winter in dealing with the cold weather and the supply challenges that we saw and then also a viewpoint that we have as far as supply availability of natural gas both in the short term and long term. So I will just start stepping through this.

This past winter, as everyone has mentioned, was substantially colder than what we have typically seen. We saw weather virtually every month during -- this graph shows every month during the winter, November through March. It was colder than what we would normally experience in a kind of 30-year average, and it was a sustained cold for the entire winter, about 20% larger overall.

We saw system throughput. That means deliveries to our customers both transport gas for their own use and customers who purchased gas from Nicor increased by 72 Bcf or about 23% above what we have seen before. Our purchases for gas for sales to our customers were up about 75 Bcf from what we would normally have in our plan for a normal wintertime.

Our challenges were exacerbated by the fact that we had a primary pipeline supplier that had experienced some performance issues, both with their storage deliverability and with some compressor stations that are on their system that limited their ability to deliver gas on many days of the winter. So that, coupled with the high demand, had a pretty strong impact on the pricing of gas as we went through the winter.

As I mentioned before, NGPL, which is a supplier to a vast majority of our customers on the Nicor system, had experienced a substantial amount of operational issues this past winter. The graph that I show there shows that there were times in which they issued hourly restrictions. I will kind of step through those for you. Remind me if not.

Kind of getting back to the previous statement of the language we speak and not maybe everyone else speaks in, but hourly restrictions meaning that they were limiting the amount of gas that we were allowed to take off of the pipeline system per hour to meet demand.

Gas demands throughout a day varies greatly hour to hour. For example, in the morning when the furnaces come on, people take hot showers, we see gas demand drive up a lot for the hour, and we were limited during some of those time periods.

We have OFO's, which are operational floors, which have a variety of things that they can do that limit your ability to take gas at either different points or at different times off the system. The OFO directive was something very specific which limited access to, NGPL customers' access to their storage services, critical times which implemented higher penalties for violations of your contract or violations of the OFO's that were in place at the time and force majeures which typically deal with equipment failures. Most notably on the NGPL system it was compression station failures.

In Orders to deal with these challenges that we had and this high demand level, we relied heavily on Horizon Pipeline. It is a service that Nicor has that effectively works almost as an extension of our transmission system where we are able to contract for firm transportation from Horizon and get service through it as if it were almost our transmission system to move gas up into the northwest portion of Illinois. It is very helpful, and the cost of the service is substantially lower than if Nicor was to try to build its own facilities to replicate the capability of Horizon.

We also shifted a lot of our tanks. A good thing about this area is, as was mentioned earlier, there are a lot of different pipelines that serve the Chicago area. So we were able to shift tanks to pipelines other than NGPL which we were able to help enhance our supply capability as well.

We also operated our system in a manner somewhat different than we have in the past in which we lowered pressures in some of our transmission systems that allowed us to get greater volumes of gas into our system than we normally could, and we operate storage in a very robust manner. There is a substantial amount of on-system storage on the Nicor system. That really was, for us, the primary benefit.

We deliver almost 140 Bcf a year of gas out of our storage. We can deliver over 2 1/2 Bcf a day of gas out of storage, and several of our fields can turn around from withdrawal to inject from one day to the next. So when we would get what were warm-ups, which sure didn't feel much like warm-ups for people, but warm-ups compared to the extreme cold, we would actually inject gas back into storage for those days to boost the pressures back up in those storage fields so that we can withdraw it the next day when it got colder to help enhance deliverability.

And it is a real testament to Nicor employees. We had several of them in downstate Illinois who were shoveling off four or five feet of snow off of equipment so they could operate that equipment on some of those days. It was a real benefit to the system. Thank you.

This graph kind of shows where we are looking for, for the supply of winter for 2014, '15.

Our storage, the storage, the aquifer storage that we have in the State of Illinois and the lease storages that we have with the pipeline companies are currently at or ahead of where we would normally be. Part of that is because we operate our storage for the operational benefit of the system. So therefore, we are going to withdraw that storage to keep the system operating as it needs to, and we will inject the system unlike in a lost of the national information that you hear about storage. Folks are trading around that, and they are making financial decisions. If it doesn't look like the value of storage will be enough next winter for them to want to inject gas now, they may be putting off on doing those injections.

We don't do that. We inject gas into storage. It will be full by the end of winter, and for all of our on-system storages we are right on track to be full before the beginning of winter. We are slightly ahead because, as I mentioned before, there were some periods of time which we were unable to access 100% of our storage from the leased storage from NGPL. So rather than being ahead in injections, what we really are is we were slightly behind on withdrawals. So therefore, we are ahead at this point in time because we didn't pull as much gas out of the storage as we normally would have anticipated doing.

So we also use firm pipeline capacity to fill our storage. We contract for firm supply from credit-worthy suppliers to fill those storages. We have no concerns about getting our storage full whatsoever.

The national picture may have a little bit more of an issue associated with it even though I think one of the things we have to keep in mind, there is an unprecedented gap in the amount of storage fields compared to where we have been in the past. But a lot of the new storage inventory that's been added to the national system in the last ten years is called high deliverability salt dome storage, meaning you can pull all the gas out of that storage field in ten days, can put it all back in about 20.

So that's a lot different than the storages that require an entire summer to get full. So I think there could be a lot more inherent catch-up capability than people are anticipating when they are seeing this large gap based on past levels of storages when we have seen cold winters in the past.

We are working with NGPL as well as the

other NGPL customers in understanding what their operational capabilities are and what our expectation could be for next year. We are monitoring their maintenance schedules and working with them to make sure that we understand what their capabilities will be for the upcoming winter.

We are exploring the availability of alternate incremental firm capacity. Either that would be acquiring firm capacity on those alternate pipelines that we utilized this winter that I spoke of or potentially getting new capacity built into the area which would be a more long term. We are planning to extend our Horizon Pipeline agreement. As I mentioned before, we used it at its maximum capability for almost over 30 days this past winter.

For the longer term on supply, you know, we are really trying to fully evaluate what our exposure to single source risk is. On the Nicor system, for example, we have close to 700,000 of our 2.1 million customers that are dependant on NGPL. It is the only pipeline that supplies that particular area of our system, and we are looking at what might be some alternatives to lessen the risk of supply issue associated with those single source areas.

We are looking at the possibility of expanding on system storage to reduce unreliability for deliveries. There is some inherent capability. Additionally what that could really do is help us out a lot with that hourly capability that I was talking about before where we can inject on one day, withdraw the next and really balance out. The hourly takes better, and there is some potential for doing that with our on-system storage that we need to do some more engineering and economic analysis on.

We will continue to hold firm capacity, all of our firm customers. We hold firm capacity in Orders to serve them, and we will obviously continue to do that, and as I mentioned before, longer term as the shale supplies grow there is actually the real potential for gas to kind of back up from the East Coast back into the Midwest, and that increases not only the potential for supply into our existing pipelines but also creates an opportunity that probably has not been available in the state in a long time which is a shorter build for even brand new pipeline capacity into the area where before you would have to build it all of the way from a supply basin, for example, off the Gulf of Mexico and build a brand new pipeline. It wouldn't have been economically viable.

But with pipelines that currently exist having gas being sourced in the east and moving gas back this direction, you only have to build from where those pipelines are located already in the Midwest potentially into the Chicago market which could turn projects that were not economically viable before into really good economic options for not only our customers for enhanced reliability but as people were talking about increased need for power generation, it could help support a lot of new capacity for that power generation as well.

Happy to take questions now or if you want to wait until everyone is done, that's fine.

COMMISSIONER DEL VALLE: This is Commissioner Del Valle. I just said to John here, I said, man, did he say a lot. You covered a lot of ground there, and it is good stuff.

But there are customers out there that are struggling with how they are going to pay that bill, right?

MR. SHERWOOD: I would anticipate. Demand was certainly up.

COMMISSIONER DEL VALLE: Because demand was up.

So you talked about the need to improve pipeline capacity diversity, pipeline capacity diversity, and you talked about the storage and that, having access to that storage, that that is going to be good for next year because you will have access.

What, with all of the things that you listed here is it fair to say that, that we are not going to have another experience regardless of how rough the winter is like we have had this time around?

MR. SHERWOOD: You know, I really wouldn't say that there is assurance. If we had an exact repeat of the weather this year or upcoming winter that we had this past winter, it would be very dependant on whether the issues that our pipelines experienced have been rectified between now and then, particularly on the issues that you were talking about related to pricing.

For example, when our primary pipeline

supplier was having difficulty in delivering our contracted volumes to us, we were moving to other pipeline suppliers, then, to deliver that gas, meaning that whoever was planning on using that capacity or, you know, there is a limited amount of capacity. It is classic supply and demand.

Therefore, there was more desire for delivered gas in the Chicago market, and there was a reduced capacity for delivered gas in the Chicago market, and that drove the delivered price of gas up to the Chicago market.

So if we experience the exact same circumstances we had this past year, I would tend to think they would not be as impactful, certainly for Nicor because many of the lessons that we learned as far as how we can operate our system and take full advantage of the maximum capacity that was available from the pipeline. We monitored that as we went along, made sure we can safely serve customers and orientated our system to allow us to take more gas off of NGPL even under their challenged supply scenario.

We also would be operating our storage with an understanding of this could be a more prolonged event as opposed to a short-term, intermittent event which would also help us to mitigate the impact.

But without real clarity as to whether the pipeline issues have been resolved, I couldn't assure you that there wouldn't still be challenges. I do believe that, as we did this past year, that we made sure all of the customers were served, but there would probably still be some pricing impact associated with it I do believe.

COMMISSIONER COLGAN: All right. Thank you for that.

Can we -- are there other questions for Tim Sherwood now, or can we move onto Rich Dobson?

Is Rich there?

MR. DOBSON: Yes, I'm here. Just waiting for them to change the slide for me, sir.

COMMISSIONER COLGAN: Okay. While we are waiting for that, I have a question for you, Mr. Sherwood.

You talked about the difference between aquifers and salt domes for storage capacity and how a salt dome can be taken down in ten days and restored in 20.

Isn't there some extended time period for the aquifer to replenish the storage capacity?

Is there something in the physics there that you can expand on a little bit?

MR. SHERWOOD: Absolutely, yeah. Your point is exactly right. It is probably best understood through the comparison.

A salt dome is literally a cavern, empty cavern under the ground. There is no geology that you are dealing with in that the gas is not passing through porous rock, it is just going into effectively a hole in the ground. So therefore, the ability to compress gas and inject it at very high rates and then there that gas gets up to a very high pressure and then therefore be able to pull it out at very high rates is a nature of the cavern that is created.

With aquifer fields, you are really injecting gas into formations that if you looked at it, it is more of something that looks more of like a pumice stone that has water inside of it, and as you are pushing the gas into that rock formation, you are slowly pushing the water out of the rock and, in those small holes within the rock the gas is actually stored within those, that porous rock.

If you try to inject too quickly into that, the gas can bypass past the water, and it gets away from the production area, and you can't retrieve the gas back out very easily. So you have to inject gas relatively slowly to effectively create a bubble for the gas to -- the folks who are real geologists are probably cringing at that, but that's effectively -- and the same thing happens when you, if you would draw gas out too quickly from an aquifer, you can start drawing water up through the wells instead of pulling gas from the wells.

So you have to operate them within a really defined window in Orders to get the full capabilities out of them. That's why it is critically important for our aquifer fields and many of them to be completely full at the beginning of the season. So we fill them regardless of whether it looks like it is a good economic trend or not and fully withdraw them so you can what we call cycling of the gas so you maintain their full capability year after year after year.

So that's why we operate and look at it just fundamentally different than what you hear in a lot of the industry, and it is one of the things that makes it more of an issue with trying to get those turned around quickly. That's why the Troy Grove and Galesville fields which are aquifers, but have slightly different characteristics which allow us to switch back and forth from injection and withdrawal are extremely valuable to our customers.

COMMISSIONER COLGAN: Okay. Thank you. Mr. Dobson?

MR. DOBSON: Good morning, Commissioners. Thank you for the opportunity to come in and talk to you. I am not going to go through some of the things that Mr. Sherwood just explained.

We at Peoples Gas, North Shore Gas experienced many of those same constraints. Looking at that just to put the weather in context, Mr. Sherwood talked about the fact that it was cold the entire winter. This is one way to look at it that it was cold a lot. Everything below the zero line was below normal in weather. That doesn't -- that's not a measurement of temperature completely but tied to heating degrees days. But think of it this way. Everything below the line is cold, everything above the line is warm.

Even in January it was a little bit warm but not for very long. Those excursions were not very far. On January 6th the temperature was minus 9 degrees F or essentially minus 74 to heating degrees days. So that would be the big spike down on about 40 degrees below normal. So that's how you can look at it in context.

Looking at storage on a national basis, that is one of the things we are talking about. You can see where we are currently. The black dotted line is the five-year average. The green line was where we were last year. The span that's on either side of those lines were the five-year high and low for any given month or week during the five-year period. The blue line is where we are today. You can see we hit the number down about 800. We are down just over 1,000. We are targeting somewhere between 3.2 and 3.6 Bcf nationally. That's if everything works out.

Like Nicor, Peoples Gas, North Shore Gas will be targeting to put enough gas in to meet the reliability that we have had in the past, and we will do this regardless for the most part on price.

We are going to put the gas in the ground for reliability purposes.

Last winter you can see the prices that we had there. The January peak load was 1.7 Bcf for Peoples and 367,000 dekatherms for North Shore. I would note for North Shore that that was a new high send out day. It doesn't mean we hit our design day which is also there.

We are taking the experiences that we had for the winter and re-evaluating the peak day and incorporating new weather into our most recent peak day designs for the upcoming year.

What are we doing for this upcoming summer and for the next winter?

We are expecting demand of about 48 Bcf and requirements of about 50 Bcf to buy. The difference between that is what we have to use to move the gas around, put it into compressors, use it for fuel to the pipeline to get it here.

We are targeting for Peoples Gas about 52 Bcf in gas storage. We are -- that is approximately the number we were at last year. Might be just a little bit above. North Shore is about 9.1 Bcf again for November 1. For North

Shore our total gas storage inventory is 10 Bcf, and for Peoples Gas it is a little bit more than 52, and the reason we are not going to be quite full on November 1 is that our on-system storage field inject is going to be full as of essentially December 1st. So there is still some gas going into the ground in November for Peoples Gas and North Shore Gas.

While nationally we tend to look at the injection cycle running April through October and withdrawal cycle running from November through March, for the Peoples Gas storage field it is November -- sorry, December through February withdrawal period and a March through November injection period.

We are expecting to hedge the gas going into the ground. About a third of it is what we are going to be putting on a financial hedge, and we are expecting our inventories to be approximately where they were at the beginning of last year for the beginning of this winter storage season. Thank you.

COMMISSIONER COLGAN: Okay. Any questions for Mr. Dobson?

COMMISSIONER MAYE: I do have a question, Commissioner Colgan. Thank you both for your presentation.

My question is directed towards Peoples. I do know that as well as storage taking a hit, which obviously that would be replaced by the time next winter comes, more so than anything infrastructure took a hit. There were infrastructure repairs that were needed and are still needed.

Where are we in that process, and will we be in a good place beginning next winter and particularly if the next winter is as brutal as this one?

MR. DOBSON: You are talking about the infrastructure at the distribution level?

COMMISSIONER MAYE: Sorry, I'm talking about the pipeline and pipes and a lot of that being needing to be replaced.

MR. DOBSON: There is some ongoing efforts by the interstate pipeline to meet the requirements under the PHMSA, P-H-M-S-A.

Is that right?

Thought I got the acronym right.

Those are -- we are monitoring where the pipelines are.

Can I tell you they are going to be done? No, I can't.

Do I expect them to be as brutal in the winter? No, I do not.

They tend to do, like we do, a lot of our services and repair maintenance in the summer months. So there really wasn't that big an issue.

One of the issues we had with the interstate pipeline, NGPL in particular, was how they were able to maintain pressure in that line. They did not have that large a compressor outage, but they were having trouble keeping pressure in their lines, and for exactly why they have yet to come clean on it completely to us at this point.

Do I expect it to happen again? I hope not. We, like Nicor, are going to be applying lessons learned in looking at what alternatives we have, and we can implement them and also to maintain our capabilities ourselves.

COMMISSIONER COLGAN: Okay. Well, Mr. Glaeser is here from Ameren, and Ms. Voiles, do you have some comment that you are going to make?

MS. VOILES: I'm here for support and any questions that you all may have.

COMMISSIONER COLGAN: Okay. Thank you. Mr. Glaeser?

MR. GLAESER: Thank you, Commissioner. My name is Scott Glaeser. I'm Vice President of Gas Operations and Development for Ameren Illinois.

And like Mr. Sherwood and Mr. Dobson, we have to talk about this past winter before we can talk about what to expect this summer and then going onto next winter. Without being redundant, to summarize it we had one hell of a winter this past winter. It is probably the most extreme winter period we have experienced in almost 25 years.

And the good news is, even though we had some significant operating problems with one of our interstate pipelines, which I will talk about as well, we were able to deliver gas supplies to our customers reliably and, just as important, at very stable prices.

Our PGA rate for this past winter, the entire winter was about $.54 per therm. That stayed that way even though spot market volatility hit prices of 10, 20, even $40 premium BTU. We are very proud of the fact maintaining reliability and maintaining price stability for our customers in one of the most difficult winters we have seen in almost a quarter of a century.

I do want to cover just briefly our peak day we experienced. Similar to Nicor and Peoples, we saw our peak day on January 6th. The good news is we design our systems, our capacity, our on-system storage and all of our resources to meet a 30-year peak design day. So we design everything for the worst winter event in 30 years. We have basically just seen a 25-year event. So as you can see by these numbers here, especially on projected design day, we actually had some reserve capacity during this extreme peak day, and we actually had even more on-system storage reserve margin on that same day.

Important to keep in mind that on-system storage is our last line of defense. If other resources have failed, we keep some of our on-system storage back. In case other systems fail like the interstate pipeline, we can then bring on that storage in real time to cover any gaps. So that's why you see a bigger reserve margin on the on-system storage than any other resources for that day.

Mr. Sherwood did a good job of covering our operating difficulties with NGPL. I do want to add a few more key points to give the Commission a full awareness of what happened.

We actually operate on nine different interstate pipelines for Ameren Illinois. Almost all of them performed very well in these very difficult times. Certain pipelines maybe had some operational flow Orderss or some critical days here and there, but for the most part they all operated very well except for NGPL.

And to give you some statistics, a normal winter is about 151 days. NGPL was operating at what we called impaired for 100 of those 151 days. When I say "impaired", either they were under operational flow Orderss, they had force majeure events where compressor stations failed or they had critical days announced which basically ratchets up penalties for being out of balance.

Even more important and more troubling to me personally and to our company was that their main line delivery pressures dropped to abnormally low levels we have never seen before to a point on certain days we reached parity with NGPL's main line pressures and couldn't bring any gas into our system from NGPL to a point where my transmission pressures were almost higher than theirs and we could have started backing gas back into their system. That was extraordinary, and we have never seen anything like that before.

The other issue that Tim mentioned and I wanted to enhance as well is that all DSS storage holders which is us, Nicor, Peoples, MidAmerican, a few other major LDC's, were forced to do injections in late February, March. The last thing we want to do in a critical winter period is inject gas. We need all those resources flowing into our citygate. We need those resources for our demand centers.

NGPL was forcing us to do injections and forcing us to specific injection points on their system, i.e., Ventura, Northern BOrders Interconnect, on Amarillo, and the Rockies Express Interconnect on the Gulf Coast. You can imagine what happened in that situation when all the major shippers of NGPL are forced to buy huge amounts of gas to inject. The prices of those points went ballistic. So it really created a huge market distortion as well. So I wanted to give that information to the Commission just to have a better feel.

We are working with Nicor, Peoples, MidAmerican and others to address this issue with NGPL to make sure this does not happen going forward.

Next slide, this is some examples of some of the price volatility. These are Chicago citygate prices, and you can see some extreme weather events, prices reached upwards of 30, even $40 premium BTU, not only driven by weather and demand but also driven by some of these pipeline operating events and critical notices as well. It is a combination of those showing that price volatility at the gate station.

It is also important to note we have seen price volatility in other parts of the country as well, especially the northeast where there is significant pipeline constraints. We saw prices upwards of almost $100 premium BTU up in the northeast. What that tells us, the nation, the industry is that there is real pipeline constraints that need to be addressed going forward.

Next slide, talk a little bit about this summer. We have already discussed about the storage injection situation for the nation as a whole. One point I did want to bring up, which is the second bullet, is that if you look at the production forecasted for this summer of about 15 Tcf, basically the native load, the normalized load during the summer season, the off peak season about 7.5 Tcf, you add in our storage injections for the nation, it is going to be about 3 to 3.5 Tcf. The wild card becomes gas generation. So gas generation could push the supply demand balance pretty hard this summer.

If we look back at 2012, gas generation burn was 6 Tcf. Normalized it is about 5 to 5.2 Tcf. If we have another hot summer with a lot of gas generation hitting, it could really cause some supply and demand, I wouldn't say imbalances but tightness which can cause some more price volatility.

Now, we do have Canada, imports from Canada to help make up some of that gap, but there is still going to be some market tightness if we have another hot summer. Really gas generation is going to be that tipping point.

Now, if we look at the forecast, what the market is telling us forward for natural gas prices, they are still relatively calm and stable. We are looking at this summer on the NYMEX trading about $4.52. That is the market telling all of the participants like us and the other LDC's that they expect supplies to be there to meet demand at about a clearing price of four fifty. So the market is not expecting any big upsets, but weather, as we talked about, Mother Nature can change the plans of the market pretty quickly.

On the next slide I'm going to drill down to our storage preparations for this summer. We are going to need about 37 Bcf to inject this summer. Our customer demands are about 16 Bcf. That's a total demand of 53. As of right now we have 42 Bcf or about 80% is already under firm contract. Now, that, about 36% is price hedged, and before we get into the core summer generation season, which is basically July, August and into early September, we will have about 50% of those volumes price hedged to protect our system, our storage inventories and customers from any price volatility from generation this summer.

Finally to wrap up on the last slide, we successfully met some extreme challenges we have seen this past winter. We had everything from extreme weather, snow, wind chills, market price volatility, but our systems, our people more importantly met the demands. We delivered gas safely and reliably to our customers at a very stable PGA rate. We are very proud of that.

We expect to do the same for this coming winter as well, and our storage injections, again, critically important for us. We are already well planned, well prepared, and we should have no problems even in the event of an extreme summer temperature event that could cause more price volatility.

With that I will conclude my remarks and be open for questions.

COMMISSIONER COLGAN: Okay. Thank you. Any questions for our panelists?

I have a question. Mr. Sherwood, you talked about how there is maybe some advantage that when you might need new pipeline build out to meet our needs, and you talked about how it might be easier because we can just add onto, tie into and extend already existing pipelines.

Can you talk about some of the -- I don't understand how that can be. Is there, is there that much capacity in the existing lines that the pressure can be increased so that if you tie in and add on new lines, that you can still pump more gas through those pipelines?

MR. SHERWOOD: Well, the actual circumstances I was referencing, probably -- again, this is Tim Sherwood with Nicor, but the circumstances I was referencing that is probably the best example of that is you may recall that the Rockies Express Pipeline got built originally to bring gas produced in Colorado and the Rockies area and traverse the country to bring that gas over to Clarington, Ohio. That was the terminus point of that pipeline. That was before the unprecedented level of production started being developed in the Marcellus and Utica area which happens to be what was originally the delivery location of that pipeline.

COMMISSIONER COLGAN: Okay.

MR. SHERWOOD: Now you have a pipeline that's got a significant amount of capacity with relatively large supply sources on both ends of it.

COMMISSIONER COLGAN: Okay.

MR. SHERWOOD: So it effectively starts to operate somewhat like a header in which people can contract and move gas from east to west or west to east in that pipeline, and since it doesn't have to cross paths, you've effectively increased the effective capacity of that, of that pipeline because they will deliver by displacement to wherever it needs to be delivered along the pipeline path.

That pipeline cuts across Southern Illinois. So therefore, there is the potential to build pipeline capacity from a project such as that up to the market area and effectively create new capacity but have a build that's probably more on terms of 100, 120 miles of pipeline, which is not inexpensive but certainly compared to 5 or 600 miles of pipeline is a substantially cheaper way of getting additional capacity into the marketplace.

And there are current pipelines that we take service from, we collectively as all the utilities here, that also cross and interconnect with that pipeline as well who could potentially expand their systems from that point of interconnect and provide additional capacity into the marketplace to help meet, one, from our perspective as Nicor, this supply diversity need that this last winter seemed to demonstrate clearly we need to address but also could meet some of these things we have heard from the electric generators who are saying we need gas, and it looks like, based on this past winter, we might need it at the same time as the gas companies need it. Obviously if there is a limited amount of capacity, we can't be sending gas to keep people's homes and sending gas to power plants to burn or to generate electricity without expanding the level of capacity that is available in the state.

So I think that's a unique opportunity, new production area to provide for us and something that we all need to really investigate as an option for the future.

COMMISSIONER COLGAN: Okay. That kind of tees up another question that I had. Really the main topic of this whole segment of our discussion today is to determine if we are going to be able to replenish the storage capacity that we depleted over the past cold winter.

I think I'm hearing from each of you three that you don't anticipate that that is going to be a problem, and I think what I was concerned about and what I think other Commissioners also were concerned about is that the competition for the gas that would be used to replenish the storage would be somehow taken up by the need for gas to do electricity generation.

I hear you, Mr. Glaeser, you are saying that you thought there might be some competition in there, and if you could expand a little bit.

Is there a potential risk there that we are not going to be able to replenish the storage?

MR. GLAESER: Yeah, I think there will be competition with the gas generation this summer. However, us and the same with Nicor and Peoples, we made pretty extensive preparations and plans to get that storage gas lined up and purchased under firm contract before we go into the summer season. That's the key issue. We have got the gas supply locked in under contracts. We have got long haul firm pipeline capacity to move that gas from protrusion zones to our leased storage on the pipelines and then our on-system storage and also doing price hedging on top of that to reduce price volatility.

COMMISSIONER COLGAN: But you were also saying that there were complications with the pipeline being able to deliver the capacity --

MR. GLAESER: Yes.

COMMISSIONER COLGAN: -- the firm capacity that you had in place.

Is that an ongoing problem?

MR. GLAESER: That is an ongoing problem with NGPL primarily. We have already done some resource changes on our system to help reduce our reliance on NGPL, and we will continue to work on those issues, and we, along with Nicor and Peoples, other utilities, are working directly with NGPL to make sure these problems do not happen again.

I will give you some precise examples of that. One of the big problems NGPL had was failure of the compressor stations. Then when compressor stations failed, they didn't have the critical spare parts in stock or in inventory close by to get the compressors back online.

We have already met with NGPL to talk to them about that issue as well as Peoples and Nicor. They are working now to get those critical spares in inventory at the critical compressor stations and to beef up compressor station maintenance.

I'm still skeptical, but we will be working closely with NGPL to make sure they carry through those promises and make sure they are ready for this summer and next winter as well.

COMMISSIONER COLGAN: Mr. Dobson, Mr. Sherwood, do you have anything to add to that?

MR. SHERWOOD: I would agree with Mr. Glaeser. I mean, I think generally speaking there is enough capability within the system to get storage full. I would expect that there is at least some risk for those folks who are not as disciplined as utilities tend to be. We start putting gas in the ground as soon as injection season starts. Scott's point, we start with plans, we make contractual arrangements and we start to fill storage.

For those that may be postponing that based on, for example, the price curve that he was showing earlier that showed it might be cheaper to put gas in storage later, you might find for some of those financial trading folks that they might find out they are all running for the door at the same time.

Now, they all go into the market to try to inject in October, and they have not price hedged, they have not contracted for the gas and have not done that, they may find constraints, and you may see that price firm up for that later period, partly due to that fact that if people are delaying, there is a certain amount of daily capability to inject that the system has in total.

If you delay that, every day you delay it means you have to go in at a higher rate later which potentially drives up the demand for gas for storage injection. But I think that's going to be more of a pricing effect for those folks who are traders and not so much for utilities because while we are certainly concerned about price, gas that doesn't get to our customers is not worth it at any price. So we have to make sure it gets delivered to the customers, and that's our primary concern. So I tend to agree with them. I don't know if Rich sees it the same way or not.

MR. DOBSON: The only difference I would add is that there is a certain amount of flexibility over the entire season for us to make sure we do hit our targets so that while I'd like to put it in relatively rapidly, there is an ability to either speed up or slow down some but not much. Again, that is where the plans have built into that, take that into account so that if there is a facility problem, we can adjust for it and still stay on track.

COMMISSIONER COLGAN: Okay. Thank you.

MR. GLAESER: Commissioner, there is one key point I wanted to add to that as well. A lot of the power generators operating today do not have firm pipeline capacity, they don't have firm transportation. They rely on interruptible or capacity release. So when the system, the pipeline systems get tight, the LDC's, us with the primary firm capacity, will maintain our flows to storage injections and those generators that try to come on but on interruptible will get kicked off.

That's the big issue about the gas and electric coordination I assume we will be talking about in July, how the generators are operating on interstate pipelines.

COMMISSIONER COLGAN: Right. All right. Very good. Anymore questions for our panelists?

Hearing none, I thank you for this discussion, and I think it is a topic of keen interest for everybody. I think it was a topic of great interest, and then the winter that we had kind of brought it so firmly into focus that it became a really big issue for everybody. I think it is a topic that we need to focus on more towards the future.

I want to thank all of the panelists for your presentations and the time that you put into preparing for being here today. We look forward to your participation on July 9th at the Gas and Electric Policy Session regarding coordination between natural gas and electricity.

The Commission will be asking the panelists at that meeting to address questions of what are the issues of most concern regarding infrastructure adequacy and reliability, what changes should be made to current natural gas and electric market business practices to improve interoperability, what problems could occur because of the uncertainty surrounding the life cycle of shale formations and possible shifts in shale gas production due to environmental or other factors and what are the lessons that we have learned from this last winter that, that were the issues that made things so extreme.

So with that, I would like to thank you again, and this meeting stands adjourned.

(Electric and Gas Policy Session adjourned at 12:16 p.m.)

CERTIFICATE OF REPORTER

I, JENNIFER L. CROWE, a Certified Shorthand Reporter within and for the State of Illinois, do hereby certify that proceeding was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this proceeding was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

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