THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

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PURPA WORKSHOP PROCEEDINGS

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Transcript of Proceedings
May 1, 2007

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BEFORE THE PUC COMMISSION

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PRESENTERS

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Reported by Carla A. Bachand, RMR, CRR

TUESDAY, MAY 1, 2007

CHAIRMAN JOHNSON: Good morning, ladies and gentlemen. This is Tuesday, May 1st, 2007. We are in Room 412 of the State Capitol for the purposes of having a PURPA workshop. My name is Commissioner Dusty Johnson. Joining me here are Commissioners Gary Hanson and Steve Kolbeck. I'd like to welcome everybody, we have a packed gallery here. I would also like to remind everybody that we are broadcasting over the Internet. We do have a court reporter so those of you that are presenting or asking questions, please make sure that you speak slowly and clearly, and if Ms. Bachand asks you to repeat something, please do so.

Again, this is the workshop for Docket EL06-018, and as most of you I presume know, Sections 251, 252 and 254 of the Energy Policy Act of 2005 required state commissions to consider new PURPA standards and we are here today in workshop for that purpose. The presentations will be more formalized, but then afterwards as far as questions go, we will probably adopt a slightly less formal format and commissioners, staff members will be able to ask questions of the presenters. At least for the first session, we will have 90 minutes for each -- rather 20 minutes for each presentation and 20 minutes for questions afterwards.

And I do -- I should mention that all three commissioners I know were very pleased with the fact that we have experts from around the state and region to help us evaluate these issues and so we thank you for your participation. With that, I'll look briefly to my colleagues to see if they have anything else to add by way of welcome or introduction, and I should also note that Ms. Wiest, our general counsel, has done a great deal of work in setting this up and we appreciate her efforts on this and we will certainly look to see if she has an introductory process as far as comments go.

MS. WIEST: No, I think you have covered everything.

CHAIRMAN JOHNSON: First time I have ever not been in error, so thanks very much. With that we are going to go ahead and kick it off. Our first presenter is Jeff Rud, he's the key accounts manager and power supply specialist for East River Electric Power Cooperative. This first session we do have four presenters and we are dealing with the interconnection for distributed generation. Mr. Rud, go ahead and proceed. I should also mention for those people listening on the Internet that all of these presentations, a lot of information will be provided via PowerPoint and those are on the Internet, so the people listening on the Internet can go to the PUC Web page and follow along as the presenters work through their information. Thanks.

MR. RUD: Thank you. Again, my name is Jeff Rud --

CHAIRMAN JOHNSON: If we could have you turn on that mike and pull it closer to your mouth, that way the folks on the Internet, I know there are millions of people across the country curious to hear what you have to say about interconnections. Thanks.

MR. RUD: Again, thank you. I'm the power supply specialist for East River Electric Power Cooperative. I deal with customers interested in owning their own generation, so I am the person who sits across the table from them when you have to explain all this stuff.

Again, a little bit about East River for those of you who aren't familiar. We are the wholesale power provider for 21 of our member distribution systems. They serve in turn 84,000 retail customers, service territory of 36,000 square miles. We are a little bit unique, we are the wholesale power provider, but we own no generation. We get our bulk power supply delivered to us from two sources, about 30 percent from the federal hydro system, from WAPA, and the remaining 70 percent from Basin Electric, another cooperative. They are our all requirements power provider and that becomes pretty important when you are dealing with customer-owned generation.

That power is delivered to us through what we call the IS, the integrated system, and Basin Electric's portion, 2400 miles, that's integrated with Western's bulk transmission system. Together 10,000 miles of transmission, and this is important because they, Western, operates the transmission system and within that system, they oversee all generation connected to it, down to very, very small levels.

Again, from those points, East River operates what we call transmission, more technically perhaps called subtransmission, 2600 miles of line over 200 substations, we connect our 21-member distribution systems to the integrated system. When we talk about DG interconnection, in the cooperative system, what do we consider? We consider it any generation that's customer owned and we consider it has to be grid-connected. Emergency backup generators that operate disconnected from the electric grid don't have the same set of interconnection requirements. So customer-owned, grid-connected are the two key determining factors that decide how that generation is handled by our network.

Where we got started on DG interconnection really had its basis with WAPA's behind-the-meter generation policy. That sets the rules for any generation over a certain size that is interconnected to the Basin/WAPA integrated system, and those rules actually were developed when the original PURPA Act came out and allowed customers to connect to the utility network. So WAPA had the behind-the-meter generation policy, set up the rules and we must operate within those rules, East River and our member distribution cooperatives.

As utilities connected very closely to our customers, we, along with I think the other utilities in the room, are seeing an increased interest in customer-owned generation. Our power supplier, working with members East River and others, in 2001 developed rates to allow the purchase of customer-owned generations, and the rates came first and the generation that was being talked about from our customers was a wide variety of sizes, very small wind turbines, medium-sized wind turbines, large wind turbines and even some base load type generation then.

So back in 2001 we had rates and we developed rates for that in anticipation of customers coming to us and saying, we want to sell power. If you have a rate, that implies that you are willing to buy and want to entertain the interconnection, so we needed some guidelines to help guide us through that process. In 2002 East River, jointly with our member systems, developed a series of interconnection materials developed with our 21 member distribution systems. We didn't start from scratch, we had a lot of help from our national organization, National Rural Electric Cooperative Association. They developed a complete, very thorough set of DG materials called the DG tool kit, sample contracts, interconnection requirements, so that was a big help to us. Our neighbors in Minnesota were going through a statewide process. We were able to tap some of that information and I have to give a lot of credit to our East River member, Sioux Valley Energy. They played a lead role in developing the interconnection requirements that helped us, it helped us work with our customers on interconnecting their generation.

The main document output of that process was what we call our interconnection requirements and this is a technical document that is designed, like most technical documents, to be reviewed by the designer and the supplier of the interconnection, the physical interconnection equipment. It's broken up into several parts, the introduction, it outlines the interconnection approval process, the rules, rights and obligations, who is responsible for what, who has to pay for what, a set of technical requirements that says that the generation cannot interfere with the existing distribution network. It specifies what protective devices and systems are required, it has a section on metering requirements. WAPA also has a meter policy that applies, and it has certification and testing criteria. Ours is about 15 pages and that's not our complete distributed generation policy, that is just limited to the technical document that describes the physical requirements and technical requirements to interconnect the distributed generation.

These requirements in our network are the same for any device producing electrical energy. If you have an solar powered inverter connection, a small wind connection, a large wind connection, a base load biogas generator, it's the same set of technical requirements. Some parts don't apply, but everyone operates under the same set of documents.

We found that this document is familiar to the DG equipment vendors. It's very close to the Minnesota DG document and it references existing industry standards for power quality, standards IEEE 519, DG interconnection standards, 1447, ANCI standards for grounding, surge standards to protect, so we think it's a good starting point to work with the customer as far as what his device, when it connects to our network, what it has to technically be capable of. It doesn't include rates or contracts, all of that is handled separately, but this is the guideline for the physical interconnection point. Again, we have worked with several of our member distribution cooperatives, their engineers, either in-house or their consultant engineers, and they have approved it and it's a good starting point that we have found. So it's been fairly successful in that regard.

So what have we done with distributed generation in the East River and our member distribution network? We have a rate, we have technical requirements, we have got a person like myself that will work with our member systems and their customers on distributed generation. How much activity have we seen? What do we have? This is a description of the customer-owned wind projects. You can see we have got 16 small wind turbines. Most of those are in Minnesota. Those were connected predating all of our distributed generation interconnection requirements. Wind, as everyone knows, is quite popular in Minnesota, so the local cooperative handled the small wind connection on their own working with the folks in Minnesota.

So the small wind predated our work, but since we have had this set of interconnection requirements, we have added a couple wind projects or our member distribution cooperatives have. Oak Lane Colony in Central Electric's territory, two small wind turbines, 160 kW. They were provided the interconnection requirements and installed their system to meet those. Again, the Pipestone School was a larger turbine. So that's the wind, what we have seen for customer-owned, grid-connected wind projects.

As far as other types of generation, we do have a biomass project, we have got a 2400 cow dairy that has -- that feeds the dairy waste into an anaerobic digester, produces biogas through the anaerobic digestion process. That biogas operates a 375 kW base load biogas generator, full-time grid connection, operating today interconnected with the grid feeding power into the network. That system was a standard design and the vendors of the system were very familiar with the interconnection requirements that we provided them.

Also fitting into grid-connected distributed generation we do have a peaking resource, a 2000 kW emergency backup generator at an ethanol plant. That's activated during peak conditions and it is grid-connected with paralleling switch gear. Again, the interconnection requirements were provided to them and they -- the system was installed to meet those requirements. That is only grid-connected during peaking conditions, but nonetheless, the length of time connected to the grid, no matter how -- if it's an intermittent resource like wind or a full-time resource like base load or a peaking resource that's only connected for a few hours a year, they still have to meet the interconnection requirements.

What have we learned by going through this project. East River and our member distribution cooperatives found -- you can see and you might go back and remember we have got 84,000 retail accounts and just a handful of interconnected generation. There's lots of interest, we think there will continue to be more interest, but we are not seeing hundreds of projects or hundreds of interconnection requests. But there is a lot of interest, so we think we are prepared to handle more, but we don't know how many projects are actually going to come, but we are ready if they are.

We have found that the equipment vendors are familiar with it, but they are having their product and they see some of the requirements and they are saying, well, would it work if you adjusted your system this way to accommodate the performance of our equipment. So that's what we have found, they are familiar with the requirements, but they might want to adjust our protective systems to accommodate their project.

You can see our connected distributed generation base is mostly small systems. The customers and the do-it-yourselfers with small generation, they might be intimidated by this process and they see a 15-page document full of what they consider technical jargon with breaker reclosing times, things of that nature, they may be intimidated, so being do-it-yourselfers, they don't want to hire an engineer to review their little wind turbine project, so that's an issue that we have seen.

Having a standard set of interconnection requirements for all the East River member systems has been pretty valuable. It allows the customer to feel that he's not being singled out because he wants to interconnect with a particular -- in a particular location. It's a standard set and we have found that to be valuable. And we have also found that the large base load distributed generation can have special needs. The effect on the network is the smaller the generation, the smaller the effect can be. As base load generation gets larger, there are additional considerations that need to be made, and again, the vendors look to the utility to sometimes adjust their system to handle those.

CHAIRMAN JOHNSON: Thanks very much, Mr. Rud. I should also probably have prefaced this set of presentations first by talking a little bit more about what this standard is about. This is about interconnection and I'll just read a couple of sentences from the Energy Policy Act. The interconnection standard just notes that each electric utility shall make available, upon request, interconnection service to any electric consumer that the utility serves and that any agreements and procedures that are established should promote current best practices of interconnection for distributed generation and that they should be just and reasonable and not unduly discriminatory or preferential. It's also worth noting a number of other utilities and intervenors did submit comments for this standard and others, and certainly those have been reviewed by the commissioners and the commission staff and are available to anybody else on the Internet.

Are there any questions for Mr. Rud? Perhaps we will first start with any questions that commissioners or advisors or PUC commission staff might have, and if any PUC staff have questions, they can probably come up to this central microphone there. Questions for Mr. Rud. I'll go ahead and kick it off. Do you get much in the way of complaints from those looking to interconnect about your process? If so, what are the most common concerns?

MR. RUD: For the small generation, the most common concern is the expense. Basically they have to pay for all of the equipment necessary to interconnect, so the expense is the main complaint, especially for the do-it-yourselfers that have a small budget, they want to -- they want to interconnect and sell power, but the expense of the interconnection and the price that is -- the value of the product they are selling is another complaint. They would like to be paid more for their power, of course.

CHAIRMAN JOHNSON: Does East River ever receive complaints that any of the technical requirements or equipment that you all require for interconnection isn't needed? Because complaining about costs is one thing but probably only has merit if those costs are unwarranted.

MR. RUD: No, we haven't had any complaints that our requirements are too difficult to meet. Again, it's based on industry standards, so even the small equipment vendors know that they have to meet these requirements, so we haven't had any complaints as far as the standards are too difficult to meet.

CHAIRMAN JOHNSON: You noted that the standards you use, the requirement you have are different than those in Minnesota. Are there any key differences?

MR. RUD: The key differences are related to the process, not the real technical requirements. They have a more detailed interconnection process than we do internally. We handle it, because of the small number, on basically a case-by-case basis. If someone wants to interconnect, we will meet with them and generally follow the Minnesota process, but theirs is more formalized with time limits on response and things of that nature. So the technical requirements are very similar, the process is different.

CHAIRMAN JOHNSON: What sort of a time frame, if somebody were to request interconnection and let's presume that they have met all the technical requirements, what kind of a time frame would they be looking at for response from East River?

MR. RUD: It depends on the size really. We operate within the WAPA/Basin integrated system, so if the generation is 150 kW or over, they have to -- they are directly involved, so they will handle the -- that requires the interconnection transmission study. It seems difficult that they would be interested in something as small as 150 kW, but they are, that's the rules, so we have to follow their process. And that can take six months to a year to get -- at least to get approval, even for a small generation connection.

Smaller than that, it's really up to the local distribution cooperative how they want to work with them, how it fits in with their -- the size of the generation and the local distribution network. If they have a farm fed by a single-phased line and they have a three-phased generator, then there's some work to be done to interconnect that. So the smaller it is, the less time it can take to interconnect.

CHAIRMAN JOHNSON: So when the WAPA/Basin, when they are involved and you said six months to a year, is the person or entity requesting interconnection, is there a great deal of work on their part during that time process or is that all done with the larger entities?

MR. RUD: We help with that. Oak Lane Colony, for instance, they had 160 kW generation. We took a one-page sheet of information about their project and we delivered that through Basin and they shepherded it through that interconnection process. So we helped the customer in that regard. We didn't say, well, here is WAPA's phone number, go talk to them. We took the information and we handled that interconnection process, not for free, but we do it at cost, but we do help them in that regard.

CHAIRMAN JOHNSON: You noted that some of the -- my apologies -- noted that some of the -- some people may want accommodations I think was the word you used. Is there any waiver process if somebody believes that a technical requirement for their particular situation wouldn't be necessary?

MR. RUD: We don't have a formalized process. Again, these are small in number. We look at each one individually. One thing we have found from talking about distributed generation or customer-owned generation is they are all different. They have different fuel sources, different interconnection systems, different types of generation. So again, we work with our customers, but we also have to insure that our other customers are not affected, but we don't have a formal waiver process.

CHAIRMAN JOHNSON: I'm trying to get a better understanding of what types of technical requirements might not make sense or rather it might make sense to have those waived or make an accommodation. Can you give me an idea of a requirement that might not make sense for a DG interconnection?

MR. RUD: I guess the answer would be no, we see the interconnection requirements as the rules of the road, so to speak, in order to interconnect to our grid. The requirements are such that in order to find noncompliance, you could do a lot of testing and we generally don't do that. When Oak Lane Colony interconnected, we didn't bring out a van full of test equipment and put it on the system and see exactly if they met the letter of the interconnection, it's just not practical to do that. The standards are in there, it must meet them. If they don't, in the future if there's a problem, we say, okay, you didn't meet the standards, you do have to fix this. So we don't see room to deviate from those at the request of the customer.

CHAIRMAN JOHNSON: So the requirements you have established, those make sense for really anyone requesting interconnection, regardless of really the fuel type or the capacity factor or anything like that?

MR. RUD: Right, they are standard for any device connected to the grid, and again, different technologies operate differently when they are interconnected. Wind turbines are different than diesel generators or biogas generators, so the designer of the interconnection has to meet the requirements and the type of generation he's connecting affects his design. It isn't the exact same interconnection piece of equipment for each one, but the requirements at the grid connection point are the same.

CHAIRMAN JOHNSON: What about reliability, could you give me an idea of what East River's opinion is toward how distributed generation affects reliability?

MR. RUD: Well, if you talk to our protection, our relay and protection guys, the large base load is an issue. We have protective devices on our system, circuit breakers that are large and very fast. We set those to minimize interruptions for the existing users of the network. If you connect generation to that, the more generation you put in, the more complicated the protective schemes can be.

And our protective relay guys, I hope he's listening now because I told him I would stick up for him in this forum, they do not want to adjust the existing protection systems to accommodate equipment that may not be able to handle a fast reclose after a lightning strike or something of that nature. So as you add distributed generation, the protective schemes can be more complicated. Workers on the line can be affected, and their thought process is the substation is the power source. Now when the lineman goes out, the substation is the power source and this dairy farm could be the power source, so it impacts protective systems and operational procedures. How negative the impact is I guess I can't say. Our guys are concerned and as it gets larger or more of them, they will be more concerned.

CHAIRMAN JOHNSON: Well, yeah, as I asked the question on reliability, it occurred to me there are two ways to look at that. One is sort of the safety issues you are speaking of. From time to time people make an argument that if distributed generation was far more widespread across a system, that that might have a beneficial impact on reliability just to the extent if a large generation source was lost, hundreds of distributed generators might in fact add to the reliability of the system. Any comments on that opinion?

MR. RUD: As a general concept, it seems like that would make sense, but multiple generators responding in a controlled fashion to a system-wide outage represents a very complicated technical scheme and the amount of technology that would have to be applied would be very difficult to make the small generators contribute to being a resource during a system-wide outage, other than the local resource for the customer where the generation sits. Having that coordinated in a fashion, especially the small ones, to increase reliability on the system would be a challenge. Again, our national organization, the NRECA, looked at that exact issue very closely and their conclusion was that it is really very site specific whether distributed generation increases reliability or not.

CHAIRMAN JOHNSON: What are the obstacles to making that work? Is it more the sophistication of the distributed generator, the sophistication of the system, the inability to communicate from sort of a central decision-making area to the distributed generators or all of the above?

MR. RUD: All of the above.

CHAIRMAN JOHNSON: I have some other questions, but we will see if commissioners, advisors or staff have any other questions. Commissioner Kolbeck.

COMMISSIONER KOLBECK: Yes, Jeff, I had one question. Do you feel that these projects are part of -- obviously the power problems as a nation, we are going to be needing more generation. Do you see this as a unique fit or do you see this as more of a problem?

MR. RUD: I think it's a unique fit. As member-owned, member-controlled rural electric cooperatives, if our customers are interested in it, we are, and our customers are, and as you can see, I feel we have been pretty proactive in working with them on interconnecting their generation.

Technically, there could be issues as I have just described, but if our customers are interested in it, we are.

COMMISSIONER KOLBECK: You don't feel that this process of interconnection is actually maybe stepping over fives to pick up ones? Do you feel that money is lost in getting these small system on line or do you feel that it's worthwhile?

MR. RUD: Well, from the cooperative standpoint, if you get into the who pays for what as far as the interconnection goes, the customer is the independent power producer wanting to interconnect to our or the other customers of the co-op's network, so the cost issue is really placed, rightly so, on the individual generator, and the utility, the cooperative, the distribution cooperative looks at that, because we have very -- a small number of these. If we saw more and more, that would be looked at as, okay, are these guys costing us more than they are worth. So at this point I don't know if it's -- if they are looked at as not worth it or whether they are looked at as a valuable resource. We are buying the output, it goes into the grid, we are benefitting from it and we are accommodating the customer.

COMMISSIONER KOLBECK: And just one last thing, just very simply, do you consider these as an asset to East River Electric, these small interconnections?

MR. RUD: I do because it allows us to learn more about the customer. They are an asset, they are producing energy, small amounts now, but the base load units like the biogas generation, there's other benefits from that process. We are allowing sale of one of the by-products from their process. We think it's good for the community. So we see them as an asset. We look at this as a positive.

COMMISSIONER KOLBECK: Thank you, Jeff.

CHAIRMAN JOHNSON: Commissioner Hanson.

VICE-CHAIR HANSON: Morning, Jeff.

MR. RUD: Morning.

VICE-CHAIR HANSON: Have you rejected any requests for interconnection?

MR. RUD: No.

VICE-CHAIR HANSON: You haven't had any situations at all where people have floundered from the standpoint looking like they were about to, but you mentioned intimidation from the 15 pages or so of technical jargon that they had to work through, and they haven't balked at that?

MR. RUD: Not in response to our requirements. Again, the small generation, limited budget, pretty soon they realize that they don't want to spend as much money as necessary to get their project connected, or they -- we get many calls about distributed generation. Not every project results -- not every call results in a grid-connected project. But we haven't had any calls that say, well, I would have done it but your requirements are too strict. There's other reasons that the project wasn't developed.

VICE-CHAIR HANSON: Do you have a handle on the type of requests for generation? Is there some anaerobic, is it mainly wind, as I would guess, but do you have some idea of approximate percentages or something of what people are thinking of doing out there?

MR. RUD: I would say it's probably 80 percent wind and if we get 10 inquiries, one or two may be on digesters, the rest would be on wind of varying sizes, small wind up to the larger winds where it would not involve the distribution cooperative, but it would be a direct connection to either the East River subtransmission or even larger projects. So mostly wind.

VICE-CHAIR HANSON: Correct me if I'm wrong, it just would seem like most of the folks in a rural area, at least a lot of them would have some type of generation facility, just to protect their assets, especially in the winter or with cattle, et cetera. Do you have any challenges with those folks with connecting generation facilities when there's not a proper linkage with the system?

MR. RUD: We have had -- I should say our member distribution cooperatives have been working with emergency backup generations for many, many years. East River operates a load control system that activates those generators at peak times. They don't operate grid-connected, they operate disconnected from the grid, and that equipment that handles that transition has not been -- has not been an issue for our member distribution cooperatives.

The line superintendents are familiar with it, they know where they are, but I'm not aware of any issues where that has caused any grid problems, other than perhaps some power quality issues with large blocks of load coming on and off the distribution system.

VICE-CHAIR HANSON: So you certainly have those catalogued and know where they are.

MR. RUD: Yes.

VICE-CHAIR HANSON: You had mentioned one of the things that I'm surprised that I hadn't thought of, but you mentioned the worker safety and especially if we have 11,000 poles knocked down and 10,000 miles of line and all of a sudden you have folks working all over the place. Is there some type of integration -- in that type of a situation, you necessarily outsource, folks come in from different states, from different service territories that are not familiar even with the area at all, and worker protection would seem like it could be a real challenge if you have distributed generation all coming on line and somebody is working on line and is unaware of that. How do you meet that challenge?

MR. RUD: With the grid-connected, like I just described, that's the interconnection requirement sets up the performance requirements for the equipment in handling the interconnection. So it has to disconnect from the grid if there's a grid problem and stay disconnected until the grid is restored. For the emergency backup generators, it's the same way. The equipment is designed not to backfeed into the system when it isn't supposed to.

And our linemen, their work practices and procedures are -- they are aware that during outages, that there are generators running all over the place and they are even more keenly aware of the issues in those than they are during regular operations. It's an issue and that's why we, I guess, have the requirements for interconnection that we do.

VICE-CHAIR HANSON: So you have a means by which to physically stop all of the generators, even though they may have been generating to the system to prohibit physically -- physically prohibit that device from operating onto the system?

MR. RUD: Yeah, that is handled by the --

VICE-CHAIR HANSON: Excuse me for interrupting. Even with the loss of electricity and power lines, you still have that ability, capability?

MR. RUD: We don't switch them off, the equipment interconnecting the generation to the grid handles that automatically. That's part of the design and the main function of the equipment, is to get off the grid during a grid outage.

That's the number one job that that equipment has to do, is to not backfeed into the grid when it isn't supposed to. So that's handled automatically. We don't, during an outage, we don't click off all the customers' generators, that's handled at the generation point automatically by the interconnection equipment.

VICE-CHAIR HANSON: In looking at the standards that Commissioner Johnson referred to and as we are examining here today, do you see where, for instance, standard 1547 or 519 are lacking in some respects? Are insufficient, let me put it that way.

MR. RUD: That depends on the local distribution cooperative. I can't say that they are -- I see that they are lacking, but others may have other opinions.

VICE-CHAIR HANSON: All right. We are practicing diplomacy here today, then. I appreciate it very much. Thank you. Mr. Chairman.

CHAIRMAN JOHNSON: We are running a little short on time, but I would look to Mr. Rislov and Ms. Wiest or any commission staff to see what questions they have.

MS. WIEST: Just a couple of quick questions. So then have you officially -- you mentioned that you had referenced standard 1547, so is that a standard that you have actually adopted and follow?

MR. RUD: It's referenced in our interconnection requirements, which have been furnished to the customer. The purchase power contract requires meeting the interconnection requirements.

MS. WIEST: So you do more or less follow them?

MR. RUD: Yes.

MS. WIEST: Then any time that they are changed or something, is there any process you go through to see if you still want to follow the updated standards or you just follow whatever 1547 standards are?

MR. RUD: It's phrased as the current 1547 standard in the contract documents.

MS. WIEST: You also mentioned distributed generation rates, you set those in 2001. Is there a process where you have gone through and changed those rates over the years?

MR. RUD: Yeah, those are set by our power supplier. A little bit about our network, the customer-owned generation, if it's feeding into the grid, we are an all requirements customer of Basin Electric, so that becomes a Basin resource, even though it's connected at the distribution level. So that sets up the rate which we develop with Basin, sets up what we will pay for generation, and those get looked at every year and sometimes two or three times a year.

MS. WIEST: Thank you.

MR. RISLOV: Good morning, this is Greg Rislov. I just have one question as well. You mentioned there were some differences in the Minnesota law and I was just curious on your system if you are following practices within Minnesota that you wouldn't follow in South Dakota with regard to interconnection, both cost and standards.

MR. RUD: The interconnection requirements are very similar. The technical requirements are very similar, if not practically identical. The process for moving through the interconnection process is different. Ours is not as -- on the South Dakota side is not as formalized. We deal with each one as a case-by-case basis. The Minnesota one has time limits for response. We work with our customers and try and meet their needs on a case-by-case basis. So the main difference is in the process.

MR. RISLOV: Maybe I could have been more specific with my question, but I was thinking with regard to the actual standards of interconnection as they relate to the system and perhaps the cost as it relates to the customer interconnecting with that system. Would one suspect that if I decided or if you decided to build a small wind facility, that the process would be more or less costly in Minnesota or South Dakota, easier or more difficult in Minnesota or South Dakota?

MR. RUD: A small wind project, I think it would be about the same. I don't think you would see significant differences in costs between South Dakota and Minnesota for interconnecting a small wind project.

MR. RISLOV: Nor would the requirements necessarily be more rigorous in South Dakota or Minnesota?

MR. RUD: I think they would be about the same.

MR. RISLOV: It's mainly dealing with the bureaucracy and getting interconnect that we are talking about, the differences between Minnesota and South Dakota?

MR. RUD: Yes.

MR. RISLOV: Thank you.

CHAIRMAN JOHNSON: Any questions by commission staff? I would just have one other request, Mr. Rud. Some of the intervenors asked that the commission not look toward NARUC model interconnection procedures if we adopted this standard but rather adopt the state of Minnesota interconnection process. I was wondering if you could give the commission a copy of the interconnection requirements that East River has so we might review those as well as a possible model.

MR. RUD: Yes, I can do that.

CHAIRMAN JOHNSON: That would be great. Any further questions? With that, thanks very much. You are off the hot seat, Mr. Rud. Appreciate it. With that, we would proceed to our second presenter, Mr. Brad Klein, who is a staff attorney with the Environmental Law and Policy Center. I see we already have his presentation pulled up, so Mr. Klein, fire away.

MR. KLEIN: Great, thank you very much. Thanks to the commission for having me out and Ms. Wiest for making the trip so easy out here. My name is Brad Klein, I'm with the Environmental Law and Policy Center. We are a nonprofit in Chicago, Illinois, dealing with a really wide range of different environmental and policy issues, including renewable energy and energy efficiency.

I'm here to give you kind of a big picture, overview of what's happening with this issue regionally and nationally. I'll talk a little bit more about what ELPC is doing in the region later in this presentation. I'm not sure which button to push. Here we go. Some of this material is going to be kind of a review for many of you guys in this room. I just wanted to start at the real basics talking about distributed generation and the types of technologies we are talking about and the types of things that you will see getting interconnected to the utility distribution grid.

I have got some examples there dealing everything from wind turbines, photovoltaics, to the types of anaerobic digesters that were mentioned earlier. One thing we have also seen, especially in our work in Illinois, is a great deal of combined heat and power generators, which allow large universities or industrial users to not only generate power on site but also use the waste heat for heating buildings and cooling and you can achieve really high efficiencies with that technology. Those types of systems are also interconnected in parallel to the distribution grid in order to provide a backup source of power.

And we have talked a little bit about what are the benefits of distributed generation, and I'd like to preface this by saying what are the benefits of distributed generation that are correctly connected and safely and reliably connected to the grid? Because I think Jeff had a good point, that unless you are doing these connections correctly, there definitely would be some concerns about reliability and worker safety, and so I think one of the real important things that we are going to do, that we are doing with this in other states is that a lot of these standardized interconnection rules I'll talk about are insuring that the connection is done safely and reliably and the standards are there to insure that. I think that's a number one priority.

When you do do it correctly, you achieve a lot of important benefits. When you are connecting generation closer to your load, there is less of a need to transmit power over long distances, you cut down on the line loss and transmission bottlenecks that you often see when you are relying on large, centralized generators. You can provide a more highly reliable source of power, if generation is located on the customer side of the meter and close to load. Offsetting peak utility power demand is important and we have seen this quite a bit with PV systems that generally are producing power at peak times on a bright, sunny day when power is more expensive, and then the bottom line as well, a lot of these distributed generation systems are using either renewable sources of power or achieving higher efficiencies and that results in cleaner air and a healthier environment for everyone.

Just in response to one of Commissioner Johnson's questions about reliability, there was a report from the Congressional Budget Office that detailed some of these benefits of distributed generation that I encourage people to look into.

And also just the economic opportunity. This is a really emerging market, and I've just included a few statistics up there just to highlight that things are moving fairly quickly with a lot of these technologies. There is I think a big economic opportunity. We are seeing it in a lot of states trying to get the right mix of policies in place to help this market emerge, and I feel that interconnection standards is a pretty important baseline piece of that policy.

Another report from the GAO highlighted a lot of the economic potential of wind power for rural communities and we are seeing in the work we are doing across the region states almost competing with each other to try to make sure that they have got the correct policies in place so they can realize some of this economic benefit.

Interconnection itself, just to start with the real basics, we are just talking about the physical connection between a customer generator that's operating in parallel with the utility grid. It's basically an engineering and business practice issue. The agreement that -- it's typically negotiated between the customer and his or her utility or electricity provider. One of the things that many people have identified is that this process on kind of a utility to utility basis, some utilities do it fairly well, some don't have a real standard process in place yet, but the process has been one of the principal obstacles to the effective development of distributed generation in many places. And states and utilities are trying to identify ways to streamline this process, cut down on the amount of time it takes, the cost it takes, while at the same time insuring that you are guaranteeing the safety and reliability of the system.

A solution that states and utilities have identified is creating these standardized interconnection rules. You are streamlining the process, you are building on some kind of technical baseline, oftentimes the IEEE 1547 has been the standard, which is referenced in the federal PURPA standard. That covers the technical requirements for the interconnection itself. There are other standards that cover the design of the equipment. Underwriters Laboratories 1741 standard covers how the equipment itself is designed, IEEE 1547 is covering the characteristics of the interconnection and how it's accomplished. And I think Mr. Johnson will probably be able to give you a little more perspective on IEEE 1547 and what it encompasses.

Another feature of standardized interconnection rules is this concept of precertification for equipment that meets these standards and a lot of times for the smaller generators, maybe you are under 10 kilowatts or so, have equipment that's been tested, been shown to be safe, been shown to have the type of inverter-based system that will automatically disconnect from the grid in case of a power outage and it's been certified to meet all of those types of standards. In those cases, if you are shown to have this type of precertified equipment, the standardized interconnection rule will allow those types of applications to move forward in a more streamlined manner and more quickly without an in-depth engineering review of the equipment.

Another feature are tiered interconnection pathways. This simply means that different types of equipment follow a different path through the interconnection process. So for a very small generator, you may have a quicker process, you may have -- it may not be as expensive, you won't require in-depth engineering studies, as you would with a much larger, let's say, over two megawatt or so generator where you really do want to have that kind of case-by-case study on where the generators are connected to make sure that it's going to operate safely on the grid.

Rules also include standardized forms and agreements. They help reduce the complexity of this process. It helps reduce the customers, I guess, intimidation, as Jeff mentioned, by getting these forms and it helps the business, the market to kind of develop where people know what to expect when they are looking to interconnect to the grid. And one thing I wanted to address, it's sometimes a misconception about standardized interconnection rules. They are only dealing with that engineering question and the business practices, we are not talking about what rates people are getting from the utility for the power they are exporting.

One thing to keep in mind as the commission considers this issue, FERC has adopted standard interconnection rules for small generators that are less than 20 megawatts and are subject to federal jurisdiction and that's kind of a fuzzy line right now. It's sometimes difficult to know exactly when you are hitting federal jurisdiction, but in general, it's when you have a generator connecting to transmission lines. So what we are talking about here today, in general again, are usually customer generators connecting to the utility distribution grid.

And there are several -- I have listed a couple things that are happening regionally. There are a lot of different model rules that organizations have issued. You mentioned the NARUC model rule, which was adopted in 2003. There have been several more recent iterations that adopt more best practices I would guess since NARUC was issued. I just wanted to point out that MADRI is Mid-Atlantic Distributed Resources Initiative. That served as the foundation for several state rules, including Maryland rules, which are just in the process of being finalizeded after a consensus workshop process, and the IREC model rules, the Interstate Renewable Energy Council has model rules as well. EPACT 2005 I will address again in a minute, but it's basically requiring the state public utility commissions to consider the federal interconnection standard and decide whether it's appropriate to implement that standard, and I'll talk more about what that means in a second.

I included this slide as kind of -- I thought it was helpful as an example of that tiered interconnection pathway that I described earlier. This is one way that some states have broken down the different categories of tiers and you start in this flow chart with your application in the top left, your first decision point. This is greatly simplified. So what it basically looks at is the size of your generator, but also many of the characteristics of where you are connecting, so let's say you are less than 10 kilowatts, you will have to follow -- one condition would be you are using certified equipment, precertified equipment there, and then there will be several technical screens that attach to that pathway to insure that you are going to be reliable when you are on the grid and it's not going to cause any safety problems. And if you pass all of those technical screens and you have precertified equipment, then you go into a more expedited review pathway where there will be less costs, less delay to achieve an interconnection agreement.

Similarly, the next tier may be -- these are just example numbers again, but the next tier might be something like if you are under two megawatts, you are meeting these other technical screens that apply to that category and you are using certified equipment again, then there may be another expedited pathway and you kind of go down this tree of decision points, to where you may have something less than 10 megawatts but doesn't meet those technical screens, they may be missing -- they may be located in a position on the grid where they can't meet that exact technical screen. In that case under this type of process, you would require a full engineering distribution study to make sure that you are not going to be causing any problems on the grid.

Here are some of the language of the federal standard and EPACT. Again, public utility commissions and certain nonregulated utilities have to consider an interconnection standard and then make a determination concerning whether or not it's appropriate to implement such a standard, and there is a time line in place for making that determination of August 2007. The EPACT standard does identify IEEE 1547 specifically and it also references, in addition to the technical IEEE standard, it says, in addition you must have agreements and procedures that promote the current best practices of interconnection. And I'd like to just highlight the importance of having, in an interconnection approach, both of those two pieces, connecting the technical requirements to a process and a procedure that melds them together, and I think that's been very important and something that successful state rules all kind of incorporate.

Some more background on our activities through the region. We have been very involved in two state EPACT proceedings, both in Iowa and Illinois. In Iowa beginning last summer it started with a notice of inquiry, very similar to what you have done here in South Dakota with the parties submitting written comments, and they have just recently issued preliminary model procedures and they are going to invite comments from the parties on those procedures and possibly hold a couple workshops to try to achieve consensus among the parties on how to get it done.

In Illinois we have been involved in a series of workshops, including one that I'm flying back for tomorrow morning with the Illinois Commerce Commission, and the utilities, the distributed generation industry, small consumers, farmers, and I guess kind of the renewable energy advocates have all been able to sit down and look at an example interconnection rule and try to negotiate what would work best in Illinois. And I think that the commerce commission staff and the utilities and all the parties really, when they have sat down and really opened up to these standards and looked at them and studied them, it's been a very -- I think we have been able to make a lot of progress. People are working really well together and I think I'm hopeful we are going to come out of this process with a good rule for Illinois.

This map shows -- this was dated in November 2006 and I took this from the Interstate Renewable Energy Council Web site just to give you an idea of the number of states that have interconnection rules in place. The yellow states have interconnection rules that only apply to net metered systems and not all of the DG equipment that I mentioned at the beginning, and not things like combined heat and power and other larger generators, but the blue/green states have some form of standardized interconnection rules applying to a broader range of distributed generation. And actually this map is changing as states go through this EPACT process, more of them are now adopting interconnection rules. I think both Illinois and Iowa may be colored in there soon. The state of Missouri, I believe the state legislature just passed an interconnection bill, so I think that state will change color, and there's some others that are working on this as well.

These are just a couple good resources for people that want to take a look at what state rules look like. They include links to especially the database of state incentives Web site, a map of the United States comes up and you can click on any state and it will bring up the whole range of state policies applicable to renewables, including interconnection rules. And that's a helpful tool to just kind of see what other states have done. IREC Web site as well includes a lot of latest news on what states are doing to comply with EPACT. It includes their model interconnection rules and other state-by-state tables that break down the characteristics of state interconnection rules.

This is my contact information. Again, I just really appreciate the chance to be here and address all of you and for your interest in this issue, and if ELPC can be a resource to help you as you move forward on this policy, we would be very pleased to do that. Thanks very much.

CHAIRMAN JOHNSON: Thanks, Mr. Klein. Your timing is impeccable at exactly 20 minutes. Well done. We will go ahead and open it up to questions. I'll start with a couple. Some of the model rules that you talked about, and I know the NARUC rules do address things like indemnification and insurance and liability. Any comments on those issues?

MR. KLEIN: Yeah, I think that's one thing that probably should be addressed in the policies and procedures piece of an interconnection standard. One thing I've heard often from the small generators is that insurance requirements, that some utilities have kind of required blanket insurance applicable only to DG that don't apply to other types of customers that maybe run backup generators or other things like that. And sometimes the level of insurance has made it difficult for the small generators to operate economically. And I think one thing that should be considered when developing the rule is to make sure if there are insurance requirements, to make sure -- to make sure they are adequately supported by the level of risk that's presented.

A lot of this equipment, especially the things that have been precertified, there is very little to no data on anyone ever filing an insurance claim for damage caused by a lot of these systems, so I think you would want to support, if there are insurance requirements, that they are targeted correctly, they are not creating in effect a barrier to the adoption of this technology and that they are adequately supported by the data. And they are applied uniformly to different classes of customers.

CHAIRMAN JOHNSON: You noted standardized forms and procedures or rather forms and agreements. If forms and agreements were simply required to be standardized within a company, within a utility, would that be sufficient or do you think some sort of a statewide standard is more beneficial?

MR. KLEIN: Again, I think that a statewide standard allows more certainty in the developing market. People know that they are not going to be subject to different terms and conditions depending on their location and it allows -- it allows this market to develop more efficiently, and I think a lot of the terms and agreements, if they are negotiated with everyone with a seat at the table, it's been at least my experience in the states I've worked in that the utilities can probably come to an agreement on what those terms and conditions should be.

But I guess from my perspective statewide and even actually regionally, one thing you are going to see here is some utilities are now operating both in Missouri, I know -- I'm sorry, in Minnesota, and we have dealt with MidAmerican in the proceedings in Iowa. I think the utilities are going to be rightly concerned about being subject to vastly different requirements in different states, so there is some value in kind of looking to what neighboring states have done, trying to streamline and make requirements consistent, not only statewide but kind of regionally as well.

CHAIRMAN JOHNSON: Do the concerns about different state procedures, do these speak more to the validity of integrity and continuity within a company's own agreements and forms as opposed to -- if South Dakota requires one particular form and Iowa requires another one, that doesn't necessarily help the multistate utilities very much.

MR. KLEIN: Right. I think you look at it from both ways, certainly from a utility's perspective, they are going to want consistency across their service territory. I think from the small generator community, they are going to want to hopefully see consistency statewide or even region wide to help them plan their business. Equipment manufacturers, when they are looking at, well, what's the type of equipment we should design and build, they are not going to want different technical standards in different states that will kind of make a patchwork of the market. They are going to want to have technical standards and precertification requirements that apply regionally so they can plan what they are going to build. So I think there is a lot of different levels of value for trying to create some kind of standard process.

CHAIRMAN JOHNSON: You noted precertification of equipment a couple of times. In most states is that precertification done by a state entity or by each utility separately?

MR. KLEIN: No, that's a good question. It's done -- the state rules will reference a specific certification standard, so the typical standard is the Underwriters Lab 1741 standard, which is very rigorous and it includes a great deal of safety factors, and in that case the utility itself and the state commission aren't going to have to do that certification process themselves, they will rely on what's already been done.

So the rules will just reference a certain certification standard and if the equipment meets that, then they will qualify for the expedited process.

CHAIRMAN JOHNSON: So truth be told, the certification is really done by a more expert entity and that just -- it's just established within state rules that their standard will be adopted, so to speak.

MR. KLEIN: That's exactly right.

CHAIRMAN JOHNSON: Finally, before I pass it on to others, you noted that a lot of these agreements end up being negotiated between the utility and the distributed generator. I think we heard from East River and I'm pretty sure we heard from some intervening investor-owned utilities they have a standardized process at least within their own company. If that's the case, are standardized agreements statewide really necessary?

MR. KLEIN: Yeah, I think that utilities are at various stages of addressing this. Some have a process that probably works pretty well. I'm not -- I haven't spent a whole lot of time studying what utilities are doing here in South Dakota, but in some of the materials that were on the docket, it looks like some of them are -- have addressed this and have rules in place.

I guess from our perspective, we have seen a lot of benefit in having that process apply statewide. I think the utilities that have more experience with this can probably be leaders in the discussions on how the rules will look and can share their experiences on what's worked and what hasn't and can look to what other states have done, what's worked and what hasn't there. But I do think there is, as I mentioned, some value in having consistent requirements across the state.

CHAIRMAN JOHNSON: Thanks very much. Other questions by commissioners or advisors? Commissioner Hanson.

VICE-CHAIR HANSON: Thank you.

CHAIRMAN JOHNSON: I saw the light on so I presumed.

VICE-CHAIR HANSON: Brad, I'll ask you a question and it's a similar question I asked Jeff. In both of the standards from the standpoint of 1597 and the NARUC, do you see either of those in need of repair?

MR. KLEIN: I think the NARUC model rules, and again, to distinguish, some of the model rules that I mentioned include both the interconnection procedures and the technical requirements, and 1547 is just the technical requirement piece of it. So a lot of model rules like NARUC would reference or incorporate IEEE 1547, UL 1741 and build those into a standard procedure with the agreements and application forms, things like that.

IEEE has continued to be updated through the years. I think it represents a really broad consensus of regulators, utilities, consumers. It was a long process to try to hammer out these technical standards that are kind of the best practice in the industry. I think that remains a very vibrant and appropriate technical standard.

As far as the process, I think the NARUC was good, it was a good first step when it came out in 2003. I think there are several features of the NARUC rules that have been surpassed by other states in other models since that time. So I think it's a little bit outdated. It probably wouldn't be the best choice as a baseline, but I think there are some components of NARUC that are good and have been incorporated into further models that have been adopted since then.

VICE-CHAIR HANSON: So with the NARUC model, do you see anything of value that exists in the NARUC model that does not exist in the others?

MR. KLEIN: No, I don't think so. I think that the good features have gone and been incorporated in some of the other models for the most part.

VICE-CHAIR HANSON: Thank you. That's all I have.

CHAIRMAN JOHNSON: Commissioner Kolbeck.

COMMISSIONER KOLBECK: I just have a quick question for you. As you see other states adopt these models, what's the process for enforcing them? Have there been any staff additions? Have they started different responsibilities in their staff? How are they handling that?

MR. KLEIN: I think that implementation question is good. Some states have done it in different ways. I think one thing that's a very important feature is to have a good dispute resolution process to try to head off conflicts before they become too cumbersome. I know the Maryland rules have a pretty good dispute resolution process where the commission can appoint a technical master who would oversee the dispute between a utility, potential dispute between a utility and a customer and allow a discussion to take place to try to negotiate through some of these problems before a formal complaint would have to be filed with the utility commission, which has a lot of -- could be quite a big expense and delay in a formal process. So I think these rules have -- if you have a good dispute resolution process, you can resolve a lot of this stuff more informally.

COMMISSIONER KOLBECK: And then you said that you have seen other states -- just one of the comments I guess from one of the utilities that had responded mentioned the Minnesota interconnection, as Commissioner Johnson had stated. Are you familiar with the Minnesota? Do you feel it's better, worse, equal to NARUC?

MR. KLEIN: I haven't spent a whole lot of time in detail looking at the Minnesota standard. I have heard that it's a pretty good standard, but again, I don't think -- I don't want to take the position one way or the other on it, but I think they were one of the states that moved forward on this.

They were one of the more early adopters of it and they have probably had some time to work out the kinks and I think my impression at least is that it's working pretty well up there.

COMMISSIONER KOLBECK: Thank you, Brad.

CHAIRMAN JOHNSON: Mr. Rislov, Ms. Wiest.

MS. WIEST: Thank you. You mentioned that Iowa had a preliminary model procedure. Is that based on one of the models, existing models that is out there?

MR. KLEIN: Iowa, I think that they have -- that their model is actually based on the Indiana rules and I haven't had a chance to look at it in detail yet. I know that there are some things they are going to have to work out with the model and it hasn't gone through the vetting process with the parties yet. I think it was intended at this point more of a framework for discussion for the parties to try to have something concrete in front of them they could discuss the various pieces. So it definitely doesn't represent the utility board's thinking on where the best -- where the best practices are yet. But I think they are going to build from that to try to incorporate maybe pieces from some other states or other models and try to build this out.

MS. WIEST: Then you mentioned Illinois. I know they are still having workshops, but did they start in a particular model there?

MR. KLEIN: In Illinois they have started with the

MADRI model rule and I think that the parties are going to recommend tomorrow that instead of using the MADRI model, to use the Maryland rules that were built on the MADRI foundation, and the Maryland rules I think streamlined a lot of the MADRI steps. I think the drafting process in MADRI was -- it's pretty confusing when you pick up that model and try to follow it all the way through. It's very complicated and it kind of has some zig-zags and turns that are hard to follow through. So the Maryland rules I think people are more comfortable with because they are a little more streamlined but still built on that MADRI foundation.

MS. WIEST: And then just one final question. I know one of the utilities filed comments and they suggested instead of adopting anything, that we should require each utility to file its interconnection process with the commission on an informational basis. Would that be helpful at all, in your opinion?

MR. KLEIN: I'm not sure, I guess it may cause -- I think one of the benefits of doing this is trying to come to an agreement up front so the issue doesn't have to be revisited later. Michigan had a pretty similar approach where the Michigan Public Utility Commission issued a rule that kind of laid out the minimum requirements of what they would like to see in an interconnection standard and then directed the utilities to file conforming tariffs that would meet those minimum requirements, which I think was -- could be an interesting approach, but one of the problems was that the kind of business practice pieces weren't spelled out on the front end and so there were a lot of inconsistencies in how the utilities were implementing these interconnection standards and they have had -- the Michigan Public Utility Commission has had to reopen the docket and they are having work groups now to try to resolve some of the problems that arose from that approach. So I guess if there can be some agreement with all the parties on the front end and trying to work out the business practices and how they fit together with the technical standards, you may be able to avoid having to come back later and fix things.

MS. WIEST: Thank you.

MR. RISLOV: Just one question. You mentioned state-by-state rules and I look at the map as it was presented before by Mr. Rud, very large service areas, multistate utilities. Is it a possibility that state by state incorporating all of these multistate utilities may end up with a more confused set of rules than just allowing these multistate very large utilities to go utility by utility with these rules?

MR. KLEIN: You know, I think it is a valid kind of concern in trying to make sure things are -- that things fit together. I know that in -- maybe Brad Johnson will be able to address this a little bit more as well, but one of the goals to work through kind of regional organizations like MADRI was so that states would have a model that they could look to and try to make those state rules consistent.

We have seen, I think there's been more of a convergence in what states are doing recently as the different states and utilities have more experience with this now. People are learning what's working and what's not and so I think the different state rules that are coming out of this process do fit together better. And there's also -- I guess it may be a step-by-step approach. I think having state rules in place definitely are better than having no rules in place, from both utilities' and the customers' standpoint. But I'm not -- one of the problems is that the entities with jurisdiction over this question are the state utility commissions and so it's been difficult. With FERC you have one standard that applies nationally to all the transmission or the federal jurisdictional interconnections and that actually has served as a good starting point for a lot of these model rules.

You will see when you look at the MADRI standard or even NARUC or some of the other state rules, that a lot of the technical screening requirements that they use are built from that FERC framework. Virtually everyone is now using IEEE 1547 and so that is a national standard. The Underwriters Laboratories technical standards are a national standard. And so you are seeing, even when there are state rules in place, they are referencing kind of these consensus documents and consensus standards that make things fit together nationally a little better.

CHAIRMAN JOHNSON: Any commission staff have any questions? Any further commissioner questions? With that, thanks very much, Mr. Klein, appreciate it. At this time we will take a short ten-minute break. We will reconvene at 10:40, I believe, so those listening on the Internet, we will continue at 10:40. Thanks much.

(Whereupon, the hearing was in recess at 10:29 a.m., and subsequently reconvened at 10:43 a.m., and the following proceedings were had and entered of record:)

CHAIRMAN JOHNSON: Welcome back to those of you on the Internet. We are half a minute away from getting started here. This is the South Dakota Public Utilities Commission PURPA workshop. We are currently right in the middle of our session on interconnection for distributed generation. The third presenter is Don Raveling who is a senior staff engineer for Montana-Dakota Utilities, and at this time, and again our format for this first session is 20-minute presentation and then similar amount of time for questions afterwards, and at this time we will turn it over to Mr. Raveling.

MR. RAVELING: Good morning, Commissioners, and I'd like to thank you for this opportunity, and good morning to everyone else. I have to apologize a little bit. I'm not used to speaking with a microphone in my face. The echo is bothering me just a little bit, so if my voice quivers, I apologize for that, too. I am actually more used to sitting in the back of the room and trying to coach others in what they have to say up front.

Just for a little additional personal introduction so that you know where I'm speaking from, I am actually a system protection engineer in the substation department and I've been doing that work since 1972 and virtually all of the interconnections that have been on Montana-Dakota's system do come across my desk, I do see them, and I do some of the studies that are involved with each one of them. So with that, I will continue with my presentation concerning the interconnection standards and Section 1254.

Section 1254 requires that each electric utility shall make available, upon request, interconnection service to any electric customer that the electric utility serves. This service to the electric customer under which an on-site generating facility on the customer's premises shall be connected to the local distribution facilities.

The interconnection policy -- Montana-Dakota has had an interconnection policy in place since 1989. The procedures are documented in Montana-Dakota's guidelines for interconnection requirements and parallel generation of customer-owned generation, and these guidelines are available upon request to any customer or we would also make them available to equipment suppliers, so virtually anyone, particularly equipment suppliers that are within our operating region are familiar with our requirements and have had the opportunity to take and look at them.

Montana-Dakota's interconnection process is very similar to that that's in the NARUC PURPA manual. It's a little bit simplified for that. This slide doesn't show up terribly well I don't think to people in the back of the room, but just to take and go over it, the process just a little bit. For very small generators, we pretty much go down the left side of the items that's on the diagram. That would be for interconnection requests that would be less than 100 kW, and these we would consider to be very small. Generally the requirements for installations of that size are very, very minimal and there would be very little cost involved, additional cost involved to the customer for those types of interconnections.

As the interconnections take and increase in size, then we move over to the right side and a little bit more elaborate study is required. Typically speaking, what we look at is the circuit capacity. Most of our distribution circuit capacities are about 4,000 KVA and when we have interconnections that approach about 15 percent of that or about 600 KVA, then there becomes significant impacts on those distribution circuits. So we start to look very hard at anything that approaches that 15 percent threshold. The actual threshold, though, can vary on the distribution circuits and it can be as little as five percent in some cases. Rarely, though, would it be above that 15 percent or about 600 kW.

Usually for these installations of this size, there will be system changes to the distribution system that will be required. It depends a little bit on how the generators intend to take and operate. If they are able to take and use what's called an open transition or take an interruption before they go on their generation, then again, the requirements are very minimal. However, if they intend to parallel with our system to either test their generators or to actually operate and generate power into our system, again, the requirements become a little bit more and we very often have to take and do upgrades on our distribution systems. The distribution systems were never really designed or intended to take and have generation connected to them, so if there is, it depends on the kind of generation that may be applied. If the generation is photovoltaic or if it's wind or if it's even small gas or diesel, those requirements vary based on that type of generation.

The EPACT standard primarily endorses IEEE 1547 for interconnecting distributed resources with the electric systems. As has been mentioned before, IEEE 1547 is a technical document and it does take and describes some of the things with respect to operation and how the interconnection should perform. It's a collaborative effort to implement general guidelines for interconnection generators and it's generally targeted at generation, aggregate generation with capacity of 10 megawatts or less.

As a little history, 1547 was originally written and affirmed in 2003 and it's expected that there will be some revisions to it. It provides no specifications of hardware or other equipment for safe or reliable interconnection, at least not at this time. It does not specify exactly how an interconnection is to be made. Actually, 1547 has been -- from when it was originally drafted, because of the size of the document that it was becoming, it was determined to take and break it up. So what we have now, there's a 1547 and a 1547.1 and there's going to be a 1547.2, 3, 4, 5 and 6. So far, only 1547 and 1547.1 have actually been affirmed. The other documents, 2, 3, 4, 5 and 6, are all in draft stages and we don't know exactly what's going to be in those final documents. So any particular standard that is written or directed and requires adherence to 1547 is really requiring adherence to a document that isn't fully developed or fully exists yet.

A little additional history, there was a standard, 1001-1998(sic). This was an IEEE standard that preceded IEEE 1547. This older document provided much more detail that was specific to a single type of grid. The document itself didn't work real well as a uniform standard for all grids because it was very dependent on the design of this particular grid and the work that Montana-Dakota did with respect to our guideline had to do with 15 -- or had to do with 1001-1998(sic). Much of the things that we put in our guideline came from this original or earlier IEEE standard, but what we did is we adopted our guideline so that it would take and properly fit our system. We had to make some adjustments so it would take and reflect a safe operation for our customers and on our system that were differing from those that were in the earlier IEEE standard. So far, as I'm aware, none of these things, these particular things are addressed in IEEE 1547, at least not on the drafts that I've seen so far.

At Montana-Dakota, we take a look at each interconnection request that is submitted and it's studied based on the information that's provided through the application process via the standard forms that are in our guideline. Montana-Dakota's guidelines, the studies take into consideration safety for our personnel, protection of the power system integrity, protection of other customers' equipment and property, and protection of the interconnecting customers' equipment and property.

Many of the customers that come to us and desire interconnection are not extremely familiar with the equipment or some of the safety concerns. They do get a lot of assistance and help from the equipment suppliers, but we do take and look at the equipment that they intend to install, how they intend to use it, so that we can take and provide some assistance to them and to help them along and through the process that's necessary to go through.

Presently we have in our guideline 19 different interconnection designs that are actually detailed in the interconnection guideline. They vary in size from perhaps five, 10, 25 up to 100 KVA for the very small. Many past requests have been in the 2,000 KVA range. Those particular ones would be considered medium by our definitions. The guideline does take and go up towards about 50 megawatts as far as a top end. But with respect to applying the guideline for the interconnections and looking at some things that are provided by some of the larger wind farms, we do in fact take and look through this guideline for input from it that may apply to even larger interconnections.

Just as an example, we have here a diagram, this is taken from the guideline. This would be a very small installation. It might be a single phase inverter on photovoltaic or it could be a small generator, a wind type generator. In many cases these are DC inverters and for small units of this type or small installations of this type, the requirements are really very, very minimal. And any additional costs that there might be to the customer would be very minimal because they really are very, very little that would have -- anything that would have to be done to MDU's distribution system to allow an interconnection.

This is an example of at least what we classify as a medium generator. We have had quite a few or at least a few, there hasn't been a lot, but we have had a few interconnections of this type. This is really very common or is commonly applied or would be common for a diesel installation. This might be someone that would like to operate on an interruptible basis. This particular one might go up to 5,000 KVA, and usually when a customer wants to operate on the interruptible basis, they like to be able to take and test their generation equipment periodically and they like to be able to parallel while they do that. That allows them to take and load test their equipment, and compared to the earlier slide, I think it's easy to see that there are more requirements for an installation of this type. There are modifications that would typically be required on Montana-Dakota's system and there would be cost to the customer involved.

And again, generators that are less than 100 kW usually are connected with very little cost to the interconnecting customer. Generators above 100 kW may have some expense associated with changes to the company's system. Those estimated costs are provided upon the completion of the interconnection study. And all interconnections, including interconnections of small generation that Montana-Dakota installs on its own system, we follow these very same guidelines.

Transmission interconnections, I believe it's been mentioned before, do have to take and apply through the Midwest Independent System Operator or MISO that would interconnect to Montana-Dakota's system. The MISO procedures are in accordance with FERC rules for small generation interconnects, which is defined as 20 megawatts or less. Or if they are larger generators, larger than 20 megawatts, then they go through the process for rules for large generator interconnects. And I would comment that this is a very -- it's a complex application process that is very time consuming. It's almost on the verge of frustrating to the customer and to us, the utility.

In summary, Montana-Dakota's interconnection guidelines are documented and they are consistently applied to all interconnection requests. The interconnection guidelines are specific to Montana-Dakota's system. There are small differences between all systems, MDU's system and the RECs. Many of the processes and many of the technical requirements would be very, very similar, but yet despite that similarity, there are differences that have to do with the type of distribution circuits that the interconnections would be placed on. That's part of the reason why we need to look at each one.

It's Montana-Dakota's position that an interconnection standard as such probably should not be adopted. We feel it is perhaps best to allow the utilities to take and design their guidelines that properly fits their utility system and their distribution system, and I would also comment that in South Dakota, I'm not aware that we have had any interconnection requests for the very small generation interconnections. And with that, that concludes my presentation and I would certainly welcome any questions that you may have.

CHAIRMAN JOHNSON: Thanks very much, Mr. Raveling. Commissioner, advisor questions. Commissioner Kolbeck.

COMMISSIONER KOLBECK: Yes, Montana-Dakota, do you have any land that's in the reservations?

MR. RAVELING: Yes, we do have some, or areas that we do serve in the reservations.

COMMISSIONER KOLBECK: Does that provide a different challenge, different standards, different rules to go by? Obviously your last line there doesn't sugarcoat it at all, but if it was to be adopted, would that present even more challenges to you, because you do have different territories like that?

MR. RAVELING: I'm not aware that anything special or unique or different really presents itself for the reservations or for other areas. I know that we have worked with reservations in other states and that some tribes and tribal agencies have in fact installed small wind generation that would be connected to the Montana-Dakota distribution system. And we applied all of the same things to that installation when we looked at it that we did to the others and so I'm not aware of anything.

COMMISSIONER KOLBECK: I just thought maybe there was more federal standards or different things that you had to -- this would be one more layer of bureaucracy on top of five others is kind of what my question was. Thank you.

CHAIRMAN JOHNSON: Commissioner Hanson.

VICE-CHAIR HANSON: Thank you, Commissioner Johnson. How do you pronounce your last name?

MR. RAVELING: It's Raveling.

VICE-CHAIR HANSON: Okay, I wanted to make it Raveling. Thank you. Mr. Raveling, some of the comments that you made in your presentation, I really appreciate your presentation, it was very good. And in a couple of spots I just have some questions, especially with the very last comment you made, but I'll save that one.

You had said in your presentation that, I'm pretty sure you are referring to 1547, that it does not specify how interconnections should be made and it does not provide specifications of the hardware or other equipment for safe and reliable interconnection. Do you believe that it should specify those items?

MR. RAVELING: One of the problems that we have sometimes had in the past is customers that desire to take and install or make installations that at least I would consider to be somewhat unsafe. They perhaps don't have sufficient interrupting equipment, they may not install breakers or may not wish to even install a circuit breaker on their equipment, and that is something that most of the things that I've seen require. I think most utilities would require such equipment.

Certainly from a safety aspect of the installation, if it goes inside a building on their premises or it may be a building that's occupied or it may be some very key facilities in some cases. Without the proper equipment installed, the risk for fire becomes high in case of some type of malfunction, and I have a great deal of concern about that type of thing, as I know everyone else would, and things of that type were required in the older standards but I have not seen anything like that in the current drafts that I've seen on 1547.

So I think it's important for the utilities that have interconnections to look at those things and to take and be sure that the installations are proper and I'm not so sure that, particularly since 1547 isn't completed yet, that it's necessarily good to take and say that we are going to adhere to that standard, you know, without proper consideration of what it contains.

VICE-CHAIR HANSON: And we were discussing earlier during Jeff's presentation, that there is health and safety issues here, especially from the standpoint if the interconnection is improperly made.

MR. RAVELING: The safety for our personnel, the linemen that may be working on the distribution circuits that have generation on them is a big concern for us. We can't always guarantee, you know, despite the fact that there is protective equipment that's included in these installations, whose purpose is to not allow them to re-energize a de-energized distribution circuit, there's nothing that says that equipment can't malfunction and it's always a concern for us. So we very much like to know where the generation equipment is located, the kind of generation it is so that we know what some of the additional risks may be.

Small wind turbines aren't any particular problem. Photovoltaics are not any particular problem. But self-excited generators, diesels, gas, waste heat or things that might take and utilize a fuel source or steam to take and drive them so that they can in fact be driven, there's nothing that absolutely prevents generators of that type from energizing a line. And it's a concern that we have and we do have some additional procedures that we take and implement when we know that there are generators of that type on a system. For instance, when we do hot line work, in many cases we take and let our dispatchers know or the customer know so that the generators aren't tested or aren't run at that time, just to try and keep some of those risks under control.

VICE-CHAIR HANSON: I appreciate those comments. Notwithstanding those comments, part of your argument in opposition to the standard is that it's incomplete and that future amendments will be made to it. Would not the commission be able to meet and examine those amendments as they came on and examine whether or not to adopt them?

MR. RAVELING: Well, certainly I believe that such things could be done, would be done. Within our own company, it's fully our intention to take and update our guideline to take them and keep it in line with the requirements of 1547. And there are many, many good things in 1547 that I've seen proposed and that presently exist and all of these things are an aid to interconnections of this type for us. Certainly when the IEEE publishes a document and we can take and point at it and show it to the customers and show it to the equipment suppliers, it makes our job, my job a little bit easier and particularly if we have to take and, you know, I don't know if argue for a breaker is the right term, but we have had to take and make requests that circuit breakers be installed. So it all helps to have those things in place.

VICE-CHAIR HANSON: Thank you. Your very last comment of your presentation had to do with a statement that I believe I misinterpreted as you said it, so I'd like you to clarify it for me. You stated something about you had not had any requests up to this juncture. Do you remember that statement and do you remember what it was in reference to, what type of requests?

MR. RAVELING: I'm not aware that we have had any requests for small generation interconnects in the state of South Dakota, at least not to this time. There have been requests for large wind farms in the past and that was through the MISO process. As far as connecting to Montana-Dakota's system, even those requests and contracts, in fact, I don't believe are -- I'm looking for the word here -- I'm not sure that there's anything going forward at all on them.

VICE-CHAIR HANSON: As a member of the OMS board of directors, I appreciate the challenges you had with MISO, the complexities of the challenges. Do you think that there is something of benefit to a standard being adopted from the standpoint of perhaps there would be more requests for renewables, more requests for generation?

MR. RAVELING: I think that generally speaking, individual customers are perhaps doing what looks economically viable to each of them. And I think those that are looking at it, they are looking at it for how can they take and save money in their operation, how can they improve their operation. So I really don't know that there would be a lot more, any additional requests. I think it's going to be some years before it really becomes economic for many small, very small individuals to take and put a photovoltaic system on their roof. We are going to see more businesses perhaps that are going to be desiring to put in diesel generation or maybe some of the micro turbines again, particularly with the micro turbines, as that technology improves a little bit from what it is, they may be looking for reliability as well as perhaps some economics from what might be gained from an interruptible rate in some cases.

VICE-CHAIR HANSON: Thank you very much. Appreciate it. Thank you, Mr. Chairman.

CHAIRMAN JOHNSON: I'll piggyback on Commissioner Hanson's question a little bit with regard to the value of interconnection standards. I understand that each utility is different and might have different needs for their system. Would there be significant inconvenience if the commission were to establish a standard or adopt a standard? If 98 percent of the provisions and requirements would be similar, if the commission were to adopt those standards and allow some flexibility within the remaining two percent, it seems to me that would provide some certainty and clarity to those interested in distributed generation but might not impose as much of a burdon on utilities. What's your thought on that?

MR. RAVELING: Well, my personal thought is no, it probably wouldn't make a lot of difference. I work with the technical aspects of the interconnections and I don't believe that there would be any end changes to those technical aspects. The interconnections have to be done in certain ways to safely interconnect. There are many problems that we encounter and have to deal with on those interconnections, particularly as the size increases, but for the very small ones, no, technically, it wouldn't really matter to us.

CHAIRMAN JOHNSON: You noted that the standard 1547 for IEEE is a work in progress and its predecessor, standard 1001, didn't completely cover the waterfront. If the commission was going to use one of those two standards as guidance to refer to, which would be more appropriate?

MR. RAVELING: The standard 1001 was actually withdrawn by the IEEE. That was withdrawn, oh, about 1997, I believe. It was primarily withdrawn when the IEEE decided to take and redraft a new standard and decided to draft standard 1547. I think a lot of the difficulty with the older standard 1001 was that it did take and direct a lot of the interconnection requirements to a very specific, specifically designed distribution system and the fact is it did not work well for many distribution systems as a result of that.

CHAIRMAN JOHNSON: I think you noted in your presentation that MDU's current procedures were based on that 1001 standard. Have they been revised in light of standard 1547 and the improvements that it made upon the 1001 predecessor?

MR. RAVELING: We made -- when we originally drafted our guideline, we used much from 1001, but we designed our guideline so that it fit our distribution system in those areas where 1001 was inappropriate for our distribution system, and as far as adherence to 1547 as such, the things that 1547 presently contains, that would be 1547 and 1547.1, are all included in our guideline as such, yes.

CHAIRMAN JOHNSON: Thank you very much. Questions from Ms. Wiest, Mr. Rislov.

MR. RISLOV: Yes, I have one, if I may. In what circumstances or what are the circumstances where MISO interconnection rules apply versus MDU rules?

MR. RAVELING: Any customer that intends to take and sell energy to the market or the MISO market that would require transmission service must go through the MISO process, and that can actually be any size. It can be very, very small generators. I've not seen anything less than two with any such desires. It's just not practical to take and go through the MISO process. It's quite expensive.

MR. RISLOV: I guess I'd have one more question. You have mentioned a number of times that there's minimal costs for interconnecting generators under 100 kW. Just very briefly, what would a range be of minimal costs? Just out of curiosity.

MR. RAVELING: Some of the small ones, I'm not aware that they had any cost at all. We just very quickly looked at what they had intended to take and connect, where they were going to connect. It took probably, oh, between four and eight hours perhaps of my time, but as long as we don't have to take and make any system upgrades as such, there is no cost to them, other than their own installation, what they have to do to take and make the physical connection.

CHAIRMAN JOHNSON: Any other commissioner, advisor or staff questions? Mr. Raveling, we talked a little bit, Mr. Klein and I did, about insurance and just the whole host of liability issues. Can you address that a little bit?

MR. RAVELING: There are liability issues. Our guideline does take and mention them, but I'm going to have to beg off on that. I'm not a lawyer so I don't know if it's really appropriate --

CHAIRMAN JOHNSON: Good for you.

MR. RAVELING: -- appropriate for me to take and answer that.

CHAIRMAN JOHNSON: Is there anything in particular with the process or the requirements that MDU has that either you think could be onerous for distribution generators or you have heard from those interested in distributed generation that is onerous?

MR. RAVELING: I'm not sure I understand that exactly. Onerous, things that might be difficult for them? Probably one of the most difficult things is those that want to take and generate and parallel with us on a continuous basis that are diesels probably have some of the most difficulty, particularly if their size is larger. What happens is when they generate onto our system, it becomes more difficult for us and for them to take and detect faults on the distribution system and in fact in some cases -- perhaps if I could go back to one of our -- my earlier slides, perhaps slide 10, if such a thing would be possible.

CHAIRMAN JOHNSON: With Ms. Douglas at the computer, all things are possible.

MR. RAVELING: I knew someone would have the power.

CHAIRMAN JOHNSON: At this point it might be easiest for you to use your backward button to navigate to the slide you want. There's a back and forward button.

MR. RAVELING: This diagram, if we look at the very, very top on this diagram, in the extreme upper left corner, we see a power circuit recloser and there's a line that's drawn horizontally across the top of this page. This line represents a distribution circuit. As we come over to the extreme right on that circuit where it just kind of seems to end, that might represent the end of a distribution circuit. When we have feed from a generator that's connected, we can find a place along that distribution circuit, and it might be the end of the circuit, it might be a lateral that comes off that circuit that we call a balance point and that balance point is a location where neither our circuit recloser at the substation nor the generator may be able to detect a circuit fault. And that's something that we have to watch very, very carefully when we take and do our system studies.

So generators, particularly the diesels or anything that has a self-excited generator that wants to take and operate a parallel with us for extended times continuously, this is an item of great concern and it often requires some very, very special things that may have to be done, depending upon where that balance point occurs. And the kind of a distribution circuit it happens to be, where that distribution circuit happens to go through, if it goes through a town, there is increased risk, if there is a heavily treed area and it's an overhead circuit, there is increased risk, and we just don't want to have any more faults that occur on a distribution circuit of that type that may be undetectable. It would be a great property risk.

CHAIRMAN JOHNSON: Thanks very much, Mr. Raveling, appreciate it. With that, we will proceed to our fourth and final presenter for this session, that is Mr. Brad Johnson. He's a consultant for the Department of Energy, Office of Electricity, National Renewable Energy Laboratory. Welcome, Mr. Johnson, and proceed at your convenience.

MR. JOHNSON: Thank you. Thank you very much, Commissioner, and thank you very much for the opportunity to come to Pierre and participate in this process. As I think many of you are aware of, NREL, National Renewable Energy Laboratory, with significant funding from the US Department of Energy's Office of Electricity, starting back in 1999, had the lead role for developing the IEEE 1547 technical standard. That process took some three, probably four years through a very extensive national stakeholder process.

Unlike in Europe, for example, where you develop a technical standard where it becomes enforceable by law, in this country when we develop technical standards, they are not necessarily enforceable by law. And what I have been doing with NREL for the last three and a half years is to work with them to figure out how it is that we now take this national standard and work through various forums, ISOs and states to begin the process of getting this technical standard implemented.

So what I would like to share with you today is some of the lessons that we have learned in terms of the issues that we have seen regarding that process, and then I think more importantly, on what we consider to be some of the best practices in terms of how states and various organizations have been able to pull all the various pieces of this big puzzle together to implement something that works within their state or in some cases within their region. So with that, here we go.

I think Brad Klein indicated before that the NREL has been very up front in indicating that lack of consistent interconnection approaches is indeed a barrier for distributed generation. What we see and have seen up until very recently is that states have either individually been implementing their policies or it's not even at the state level, you have something like 115 investor-owned utilities, I'm not sure how many are co-ops and municipalities, but typically each one has had their own interconnection practices and it hasn't been until very recently that we have seen states at least looking at developing something on a statewide basis, and a lot of that has been driven recently of course by EPACT.

And frankly, the tension that we see out there is that, on one hand, you have the utility basically saying this is my equipment, this is my people, there is some very real safety concerns for putting generation on a grid that's been designed with the assumption that power flows one way, I need to decide how that happens, I need to write the rules of the road. On the other hand, we have the DG community saying you are standing between me and a market.

There's a lot of knowledge out there, there's a lot of money out there behind this technology today that can't get to market because there is no clear path on how to do that, and what we would suggest is that the way to do that is to not have the utilities individually decide what those rules are, that there ought to be some type of collaborative process through a working group process where you can kind of look at what the various interests are and strike a reasonable balance. I think as I go through this, I can talk to some processes that we have been involved in where that has happened. And really what that kind of ends up and where we end up focusing is in four areas with this last bullet.

It's the technical standards and then it's the processes, and I really, as part of this discussion, really want to emphasize kind of the process part of this because this is how you insure that what you think you are building is what actually gets built and that it is indeed safe and addresses the concerns that the utilities have that they can continue to operate their systems safely and reliably.

In terms of kind of where we have been participating in this, our goal is to come in as a completely neutral third party. My background in this, I have worked for large investor-owned utilities where I have been intimately involved in interconnection policies. I was president and chief operating officer of a wholly-owned utility subsidiary that was basically working across the country trying to get individual utilities to adopt some advanced interconnection technology. I've been on both sides of this fence. And our goal through this whole process is to basically insure that when we come in, we facilitate that type of discussion, and there's some key areas that we have been involved in here.

A couple years ago we started working with PJM, which is the equivalent of the MISO. The way the PJM process worked is there were three-way interconnection agreements. You signed an interconnection agreement with PJM, with the developer, and with the local distribution company. Each one of those agreements was based on evaluating the project against the individual utility's interconnection requirements. A very cumbersome, time-consuming, expensive process. We worked with PJM to basically set all 17 of the transmission owners around the table and say, can we move off those individual transmission owners' technical requirements and adopt one common technical requirement across the PJM footprint based on IEEE 1547.

That process took about a year and it was very painful, it's going through 1547 line by line by line saying, can you agree to this, can you agree to this, if you can't agree to it, why not, coming back. At the end of the day, we came out of that with all 17 transmission owners agreeing to a slightly modified version of 1547. I don't want to say it's identical, but it's awfully close. We then built upon that to actually get agreement to go from zero to two megawatts to two to 10 megawatts and then most recently the agreement was for 10 to 20 megawatt systems. Those agreements have all been filed and accepted with FERC.

We then worked very closely with MADRI. MADRI stands for Mid-Atlantic Distributed Resources Initiative. MADRI's function in life is to decide how we can get more distributed resources in the Mid-Atlantic markets, working primarily with the five Mid-Atlantic state regulatory commissions, with help from PJM, FERC and DOE. Interconnection was designed early on as a major barrier to seeing more distributed resources in the Mid-Atlantic markets. We spent a very long, hot, painful summer in Philadelphia, kind of reminds you of the Constitutional Convention, I guess, where we got the DG community and the utilities around the table and we hammered out a model interconnection procedure for the states to then consider based on what we felt were the best practices at the time.

The best practices that MADRI agreement was modeled off of was the FERC small generator interconnection procedures, as well as New Jersey. New Jersey was selected because it was the first comprehensive state policy that we had identified at that time that we felt really addressed this tiering concept in that it provided expedited procedures for different sized projects. And if you think about this, if 1547 applies from zero to 10 megawatts, there's a big, big difference between interconnecting a 10-megawatt system on a district feeder than a five kW PV system on somebody's house. And we need to recognize that through these state rules.

We felt that New Jersey did a great job of that. FERC does it, but it does it through a convoluted way. So we put those two documents together. Pennsylvania immediately adopted it as its state interconnection procedure. We just finished up the process with Maryland. I guess to our way of thinking right now, Maryland, in terms of the work that it's done, probably represents what we feel is kind of the best kind of combination of integrating the technical standards with state interconnection procedures and standard agreements. There was unanimous consensus amongst the stakeholder group that developed this, including the large utilities that participated in it to take this now to the Maryland commission asking that they adopt it as a state procedure.

We are currently involved with Oregon in developing a very similar process. What's been interesting in Oregon is that we are dealing with some large multistate utilities, principally Pacific Corp, that have rural service territories very much like you have in South Dakota. There was a lot of discussion on whether or not 1547 gives them the protection they need on some of these rural feeders, as well as the procedures. At the end of the day, I think where that process stands right now is the utilities are getting very comfortable that what we have done kind of on the east coast works out in the west as well.

Then we are just in the process right now of there's a lot of activity primarily in this area and if you look kind of at a map as to where we have been, we are very interested in trying to kind of leverage our resources in terms of trying to go into different regions of the country where we can have an impact. We have been in the Mid-Atlantic and Northwest. We have not been participating in the Midwest. We are very much looking forward to participating in some of these working groups. I'm going with Brad Klein tomorrow to Illinois. We have started participating in that process. We are here today.

I wanted to talk a little bit about kind of the technical standards and the process, and talking about the technical standards based on the previous presentation, there are a couple points I really feel that I need to clarify here with respect to what 1547 does and does not do. 1547 applies to the interconnection equipment, it does not apply to the small generator facilities, just the equipment that is used to interconnect a small generator to a distribution system. So for example, if I have a PV system, a PV system typically includes panels that go on the roof and the inverter. The inverter is what we would define as the interconnection equipment, so that's where those standards apply.

There are two primary sections to 1547. Section 4.0 defines the minimum technical requirements that that equipment has to meet and those requirements are oriented primarily towards safety and reliability of the existing distribution grid. There is a Section 5.0 that basically requires that anybody that installs something to 1547 standards has to test it and the testing requirements are very specific. It says that there has to be a design test, a production test, a commissioning test, and then after it's built, there has to be a periodic test. And when you look at that standard and how it's designed and how it's intended to be operated, its primary focus is safety and reliability. It does not specify hardware. You cannot do that with standards. There's antitrust considerations to doing that sort of thing.

Standards are used to basically help create markets and invite as many market participants as you can to come in and build the hardware that meets those requirements. What is absolutely imperative is when you have a technical standard is that you have a process that accompanies it to make sure that you are employing that technical standard the way it's intended to be employed, particularly with respect to testing, and I'll talk about that in a couple more slides.

We have gone in through these processes that we have been involved in and across the board it seems like when we first start off the process, we go around and survey the utilities about what is the basis for their existing technical requirements and they say they are based on 1547. We have done -- in two instances, we have done detailed audits, we followed up on that, and the first case it was with PJM where we went back to each of the 17 transmission owners and said, we want to see your technical requirements and we want to do side-by-side comparison to see how they match up with 1547.

What we found very quickly is that it was very difficult to interpret those technical requirements. This was not me, this was the experts from NREL as well as the PJM interconnection people coming in who are experts in this trying to figure out if they could interpret the individual company interconnection requirements and how they would apply and how they would match up with 1547. In some cases they could not connect the dots. They found that the technical requirements were in multiple documents, they were subject to interpretation, there was not a lot of transparency, and there was some anecdotal information that suggested that, depending on who you talked to on what day when you went into the utility, you got different interpretations of what those requirements are.

Then the biggest concern is that there were a lot of additional requirements. In some instances you could kind of track where the 1547 requirements were. But then there were all these additional requirements that kind of got added on. And a big part of that year long process that we spent with the PJM transmission owners was kind of trying to get behind those additional requirements to understand them. And in every case those additional requirements went away. There are, in the existing PJM technical requirements, there are no additional requirements beyond 1547. There are, in some instances, there is some documented evidence or some documentation in the standard that says, this utility and this utility is going to have this interpretation, which probably differs from 1547, but there are no additional requirements that are tacked on.

Went through a very similar process in Oregon. There was a lot of push back initially that 1547 doesn't apply in this part of the country. And there was some real issues particularly when you go out on the rural feeders. Where we ended up there is once we kind of spent -- we spent a lot of time, half the working group sessions were devoted to looking at this issue, does 1547 work, and we came out of that with the answer that, yes, it does.

I'm not pointing this in the right direction. There we go. The key challenge here, and I'm going to kind of move from the technical standards over to the process side of it. We see three components to that. We see the interconnection procedures themselves, which in at least a couple of the states we are dealing with right now, those are actually being developed through formal state rule makings. Others are considering tariffs, but the majority of the states seem to be looking at an actual formal state rule.

Then we look at the standard agreements and that basically -- and what's integrated into this is the technical standards. Let me give you an example of where the integration is so critically important on this. What we feel the best practice procedures do is they have this tiered concept. Frankly, we think kind of a four-tiered concept makes the most sense. And at the small end of that, you have a level one and level two. Level one would be 10 kW systems and smaller, level two is two megawatts and less and depending on whether or not these systems meet certain conditions, i.e., they use certified equipment, they pass certain technical screens, they are eligible for expedited review, in which case the utility has somewhere between 20 to 25 days, depending on the size of the project, to either give it a thumbs up or thumbs down as to whether or not they are going to approve it under the expedited procedures.

That does not give the utility a lot of time to come in and really kick the tires a lot and to look at a lot of the things that they might have looked at in the past. What we find is that there is a lot of institutional inertia with utilities where they feel that they need to protect not only their systems but the customer as well. Customers have pushed back and said, we are big boys and we want to play with the big boys and if we meet the technical requirements, we want an expedited process for doing this. The way that we do this is using the certified equipment, so somebody else is actually doing the testing.

But what's kind of integral to all this is a provision through the standard agreements and the procedures for the utility to do a witness test, which means that once this facility is built, the utility comes in and has the ability, doesn't have the requirement, but has the option of coming in and actually testing every piece of equipment that gets interconnected to their system to make sure it meets the technical requirements of 1547.

Now, once that equipment gets built, how do you insure that it's operated consistently with 1547? How do you know it's not creating some type of power problem? How do you know that the disconnect equipment is working appropriately so that when the grid goes down, that the unit de-energizes so it doesn't backfeed and put power back into the grid? There are provisions through the periodic testing to come back and insure this. Now, this all gets kind of integrated into the standard contracts. Our concern is that when you cherry pick this, when you have a standard here, you may have a technical requirement or an interconnection agreement over here that picks this up, you have another utility that doesn't, that you now don't have the integrated process.

And we feel that in terms of kind of maintaining the integrity and the safety of this whole process, that integration is absolutely critical. From a market standpoint, we feel it's absolutely important for the DG community to understand going in what's required both from a technical standpoint, but as well as being able to have standard agreements that they can sign without having to go in and spend enormous amounts of legal time going toe to toe with utilities executing these various agreements.

And in the Maryland process, we had seven stakeholder working groups over a period of two and a half months. Over half of those working groups were focused on the standard agreements, making sure that we could get, in this case it was utility agreement on things like insurance provision, indemnification, what happens if somebody doesn't pay, what happens if somebody -- if I come in and find a problem, they don't disconnect, those kinds of things. And what happens in the market today is individual DG developers either take the utility standard contract or they spend a fortune trying to negotiate terms and conditions that they feel are appropriate.

Finally, what I want to do with this slide, and this is actually the important slide, and I see I'm running out of time here, but I wanted to just kind of share with you kind of the evolution and the history of kind of how we have gotten to where we are at today. And this goes -- this is going to be hard to read in the back of the room, I apologize, but I will summarize it quickly. What this time line does is kind of breaks this down into two separate activities.

On the top you see the interconnection procedures themselves and on the bottom it's the technical standards, and what I want to do is kind of share with you kind of how they have evolved over time. Really the genesis for this goes all the way back to 1999 on the procedures, you had PJM as part of its open access tariff, when the ISO was formed, actually agreeing to a standardized interconnection process. That, as I understand it and in talking to some of the market participants, that process more than anything else opened up the generation portion of the competitive markets in the Mid-Atlantic by having standardized agreement and a process for interconnecting these large generators. FERC subsequently adopted the PJM process for its level four study process that was used in the FERC small generator interconnection procedures. They are virtually identical. At the same time, you had IEEE starting its process, as well as UL with the 1741.

Now, the point I want to clarify about 1547 and the comment that the standard is not developed yet, well, there is a family of 1547 standards. 1547 deals with the minimum requirements for the interconnection requirement. 1547.1 deals with the testing. Those have been approved. There are a series of additional IEEE standards that deal with communications, with operating microgrids, with developing a communications protocol for interfacing with these distributed generation systems, as well as dealing with potentially systems that might be larger than 10 megawatts. Those are the dot two, dot three, dot four, dot five and six. They really do not have direct bearing on the 1547 standard itself. And there is a process under way to develop those.

1547 will be enhanced once those other -- and they aren't all standards, some of them are guidelines, okay, and guidelines do not kind of carry the same weight as a technical standard. So I think it would be somewhat of a mischaracterization to say that 1547 is still a work in progress. The model agreements that we are working with at the states specifically reference 1547 as they may be modified and amended from time to time, as well as 1547.1. They do not reference any of these other standards. But you can see on the bottom is that work is continuing to progress at a fairly decent rate.

On the top what we find, and I'll kind of walk through this very quickly here in terms of the procedures, is that you have the NARUC procedures that were developed back in 2003. I think the comment has been made several times today that a lot has transpired since NARUC came out with their procedures and that's what I hope the top part of this time line shows. Subsequent to NARUC, you had the New Jersey procedures, which I talked about. FERC issued their small generator guidelines. All of these early kind of best practice models, if you will, talked about this concept of certified equipment without really defining what that meant and it was a big problem because people were being asked to approve this stuff on an expedited basis without really knowing what constituted certification.

So we put together a big stakeholder meeting, NEMA hosted this in 2005, where probably 30, 40, might have been 50 people sat around the table and we hammered out what does certification mean. This is where we came up with this concept of testing by a nationally recognized test lab to IEEE 1547 to the IEEE -- I'm sorry, UL 1741 to the IEEE 1547.1 testing procedures, which is kind of the basis for what now constitutes certification.

Subsequent to that we had the MADRI process, which was then adopted by Pennsylvania, and different variations of this MADRI process are now being kind of pulled into some of these state processes. I would suggest that right now the starting point is not the MADRI process, which is now two years old. It's probably more something like what you see is kind of coming out of this Maryland process. As Brad Klein indicated, I think there's been a lot of emphasis placed on kind of the drafting of this to make sure that we get this thing as simplified as we can, as well as there's been a lot of refinements on the integration in making sure that the standard contracts are indeed something that we can adopt on a statewide basis and making sure that these three pieces of puzzle do indeed fit together.

So with that, let me kind of wrap this up and say that DOE has tried to kind of address this whole issue of what constitutes best practices. You go on their Web site, there's a URL link there, I'm not going to read this, but there is an attempt at least to provide states primarily through EPACT proceedings with some type of guidance on what constitutes a best practice process. Thank you very much.

CHAIRMAN JOHNSON: Yes, thank you, Mr. Johnson. Questions for Mr. Johnson. Commissioner Hanson.

VICE-CHAIR HANSON: Mr. Johnson, I appreciate your presentation and thank you for picking up on some of the questions we had earlier and answering those in relationship to the evolution of the IEEE. So when you say it's not a work -- it's improper to refer to it as a work in process, won't there be changes to it in the future?

MR. JOHNSON: I think, as there is with any technical standard, there is a process that IEEE has for updating those standards and the expectation is that IEEE 1547 will be updated, and in the state procedures that I'm familiar with, usually what they do is they refer to the technical standard as IEEE 1547 2003 as may be amended and modified by IEEE.

VICE-CHAIR HANSON: Thank you for that clarification. Since this was primarily designed for installations rated up to 10 MVA, do you think that the commission, if it adopts 1547, would need to adopt standards, additional standards for those above the 10 MVA?

MR. JOHNSON: The 10 MVA limit, as I understand it, is in recognition that 1547 is intended to apply to small generators that would interconnect to distribution systems. Once you start to get above 10 MVA, a lot of those tend to interconnect at transmission levels so they now come under the jurisdiction of MISO or PJM. What's confusing about this is both PJM and FERC, for example, have defined small generators as 20 megawatts. Now there's this 10 megawatt gap, so what do you do with that?

And PJM I think did a pretty decent job of addressing that through a stakeholder process where they said, let's take a look at 1547 and let's recognize that some of these 10- to 20-megawatt facilities may be connecting at transmission level voltages, what does that mean and what do we feel we need to change? And there are some changes in that document to 1547 that recognize that.

I think from a practical standpoint, what I see happening here is that anything above 10 megawatts is likely to undergo this what I call the study process, it's not going to be interconnected on an expedited review. And I think that there needs to be a standard in which to evaluate those under a study process, but I would certainly encourage you to look very closely to what in your case MISO is doing with respect to those 10- to 20-megawatt projects and try to dovetail with that, because from my point of view, the state process for those types of projects should mirror, hopefully a little more efficiently than what MISO is doing now, but it should mirror the MISO process.

VICE-CHAIR HANSON: Thank you for anticipating that. That convolution was going to be my next question. I appreciate your anticipation of that. In arguments in favor of adopting this standard, there has been some written arguments stating that it would encourage renewables. Would it encourage -- how do I phrase this -- would it encourage greater megawattage of renewables or would it just simply encourage a lot more small renewable generators?

MR. JOHNSON: Well, I have a hard time addressing that question because having breakfast this morning, I saw the article in the paper where the chairman was interviewed talking about what a great job you have done here in keeping electricity rates down. And you are at something like 70 percent of the national average.

Really what you are talking about is the market opportunity here, okay, and ultimately what's going to drive DG is whether or not there's a market for it. I would strongly suggest that what you do here today with respect to interconnection standards is going to have a big impact on that market by whether or not there continues to be a barrier or do you minimize that barrier. But ultimately what's going to determine the amount of penetration you have here in South Dakota is the types of policies that you as a state develop to encourage these types of resources as well as what the market conditions are. And for example, a lot of states have these portfolio requirements that they have decided that it's worth paying a premium to develop some of this. The market is now responding, they are responding in a big way.

VICE-CHAIR HANSON: Albeit forced to respond.

MR. JOHNSON: Absolutely.

VICE-CHAIR HANSON: You had stated that there's too many, or words to this effect, excuse my paraphrasing, too many interconnection agreement processes from individual utilities basically inhibit distributed generation. And yet we have heard testimony here today from folks saying that -- or at least presentations that, no, we haven't had those requests, we haven't had those challenges. Is that a national phenomenon or is that localized?

MR. JOHNSON: Here is my perspective on the market right now, is that the DG market, except for wind and solar, is having a really difficult time, but there are some pretty significant developments that I think could change that and those developments are the emphasis you have seen on clean technology in regard to climate change, and then just sheer, this sheer amount of capital that is out there in hedge funds and venture capital funds right now trying to get into this space, and I think it's hard to really gauge where all that could possibly kind of go.

You have to wonder if you are not seeing this activity, what does that mean? Does that mean that it's too much of a hassle, it's too much of a burden, the hurdles are too high? Or does it just mean that this is not a market that exists and it's not worth really trying to help it develop?

VICE-CHAIR HANSON: Thank you. Thank you, Mr. Chairman.

CHAIRMAN JOHNSON: Other questions. Ms. Wiest.

MS. WIEST: I had a quick question. In the Maryland process, then, you stated at the end of it the workshop agreed to rules and agreements. Do you anticipate many changes, then, made to what they have agreed to or you can't predict?

MR. JOHNSON: You know, it was a stakeholder process, there were representatives from solar, the USCHP coalition and the three major utilities, PHI, Allegheny, and Baltimore Gas and Electric, so those were the people that basically agreed to it, and it will go now -- it's been formally submitted by the working group to the commission and the commission will decide whether or not they are going to just accept the recommendation as is or whether or not they will hold additional formal hearing before they do that. I have no way of predicting kind of how that might happen. I do know that the commission staff is looking to basically get this on the commission agenda and have them decide what they are going to do with it sometime late this summer.

MS. WIEST: Thank you.

CHAIRMAN JOHNSON: Mr. Rislov, Commissioner Kolbeck, any commission staffers, any questions? Thank you very much, Mr. Johnson. I appreciate your comments. It is I believe five after 12:00 or so. We are scheduled to return from lunch at 1:10. It would be my intention, if my colleagues are okay with that, to stick with that schedule and take slightly more than an hour for lunch. When we return, we will deal with fuel diversity.

I should mention as a final note that to the extent that anybody has concerns or disagreements with the presenters' comments or they believe something has been omitted, obviously there is an opportunity for anyone out there to file written comments with the commission as part of this proceeding. Thanks very much and we will see everybody at 1:10.

(Whereupon, the hearing was in recess at 12:05 p.m., and subsequently reconvened at 1:10 p.m., and the following proceedings were had and entered of record:)

CHAIRMAN JOHNSON: Welcome back to those of you on the Internet. It is 1:10, we are reconvening the South Dakota Public Utilities Commission PURPA workshop. Our second session, which we will be dealing with fuel diversity, will be moderated by Commissioner Hanson. Commissioner Hanson, take it away.

VICE-CHAIR HANSON: Thank you very much, Mr. Chairman. The workshop continues this afternoon, as Commissioner Johnson stated, with fuel diversity, PURPA standard 12, which requires the commissions to consider adoption of a fuel diversity standard and that statement in the EPACT is that each electric utility shall develop a plan to minimize dependence on one fuel source and to insure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies. And as I stated, the commission is required to consider that standard, and with us today for presentations on the fuel standard is Mr. John Hines, the director of energy and supply planning for NorthWestern Energy, and Alan Welte, director of generation for Montana-Dakota Utilities Company. And our first panelist this morning, excuse me, this afternoon, is Mr. John Hines. John.

MR. HINES: Thank you very much. I'm pleased to be able to come here and be able to talk to you about this topic. What I thought I'd do today is speak to you from the perspective of why NorthWestern has serious concerns about this proposed standard, but I'm also available to answer questions. We do have a portfolio with a substantial portion of renewables and I can talk to you through the question and answer portion about some of our concerns that we have had implementing these sort of resources and under a mandated format.

So with that, Commissioner Hanson, you noted a couple clauses in the proposed standard number 12 that cause us a significant amount of concern, primarily that the utilities shall develop a plan to minimize dependence on one fuel source and also insure that the energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable.

Both of those mandates or requirements to me single out that they are excluding several important factors. One, there is no mention about costs. There is no mention about price stability, reliability or affordability to customers. All of those issues need to be considered and are considered when the utility does a planning and resource acquisition.

So I can see how in the abstract a mandated fuel diversity standard can sound like a good idea. However, requirements such as mandating diverse fuel sources should cause everyone to pause. The resource portfolio that NorthWestern has developed was put together with care and recognition of numerous factors. Just one factor is the geographical comparative advantages that accrue to utilities in different locations and the fuel sources that the utility is then able to take advantage of.

For example, utilities in the Midwest often have a high percentage of coal in their portfolio and there's a reason for that. Utilities in the Pacific Northwest often have a high percentage of hydroelectric power, which actually is not considered renewable, large scale hydro isn't considered renewable. They also have a high percentage of that in the portfolio. And the reason for that is consumers are best served by utilities are requiring resources that result in the lowest cost as a product for consumers. You know, these comparative advantages utilities recognize and they frequently translate into lower prices for utilities. Ignoring this reality or mandating different resources will likely result in customers paying more than necessary for their electricity.

I suggest a key piece to your deliberations on this standard would be first to determine whether there really is a problem that you are trying to solve here, whether there's a need for such a standard. NorthWestern concludes that there is not a problem that requires this mandate. Diversity for the sake of diversity makes no sense and such a standard could very well end up being counterproductive. One of the commissioners earlier today had the phrase are we stepping over five dollar bills in order to pick up dollar bills. I think that that was very applicable to this standard right here.

To give you a little bit more background on the NorthWestern portfolio to understand where our concerns are coming from, with your indulgence, I would quickly go through the portfolio that we have put together to serve South Dakota customers. We have a fairly diverse portfolio. We have joint ownership in three coal plants and we wholly own nine small gas and diesel peaking plants. The first plant, coal plant that we have is Big Stone. It provides around 34 percent of our peak summer demonstrated capacity. We have Coyote I, another coal plant that's a lignite plant. That provides around 14 percent of our peak summer capacity. We have another coal plant, Neil Electric, it provides about 18 percent of our total summer capacity, and then the combination of the Nine Peakers provides around 33 percent of our total summer peaking capacity.

And just a note on the Big Stone I plant, it has approval to burn a variety of alternative fuels as well and it's my understanding I think we burned -- around 1.3 percent of the output came from alternative fuels at Big Stone during 2006. We also have our purchase agreement with a supplier that provides us around 40 megawatts of summer peaking capacity as well. So from a peaking capacity, we have a fairly diverse portfolio already and that's put together without a mandate. I recognize from an energy perspective that it is fairly dominated by coal. But from a peaking perspective, which oftentimes shows the most price variability, in other words, when the market is most stressed is at peaking periods, we do have a diverse portfolio there. So we have the resource portfolio we think is fairly well diversified already.

Just to leave you with a couple of other reasons why we believe this is probably not needed at this time, first is that you already have existing planning and siting regulations that we feel provide the commission with sufficient latitude and an avenue if you believe diversity is more necessary in the future. For example, your facility siting rules where it requires us to provide information on the alternate resources considered in the construction of the facility, we believe that gives you a good process into the utility's planning if you have issues.

Also in our 2006 10-year plan that has been filed with the plan, we note that to meet our future capacity needs, we are looking at two 25-megawatt simple cycle gas turbines, which would further diversify our summer peaking concerns away from coal and more toward a different fuel. In fact if we construct those facilities, I believe we are over 40 percent for the summer peaking capacity being served from resources other than coal.

Finally, I know you recognize NorthWestern is a multiple jurisdiction utility, and in Montana, in December of 2006, they specifically declined to implement fuel diversity standards for any of their jurisdictional utilities and they believe that the existing laws and rules as well as the RPS standard they have in effect in Montana is sufficient to insure an adequate amount of diversity for utilities in Montana. So to the degree that consistency is obtainable obviously with other commissions, we certainly push for that.

And finally, perhaps maybe even most important of all is that we are not hearing from our customers that they are demanding a more diverse but potentially higher cost portfolio, and those factors taken together leads us to the conclusions as noted at the very beginning by Commissioner Hanson, the standard needs to be -- there's a mandatory obligation upon the states to consider the standard. We respectfully request that you not implement the standard as put forward. That would conclude my remarks and I would be happy to entertain any questions.

VICE-CHAIR HANSON: Thank you very much, Mr. Hines. Do any of the commissioners have questions? Commissioner Kolbeck.

COMMISSIONER KOLBECK: I do. Do you see this as something that is common sense to all companies? I know NorthWestern is diverse and you feel that it would be impeding on NorthWestern, but do you see the industry as a whole, that this is something that's overlooked that needs to be mandated or do you see that all companies for the most part in the industry abide by this?

MR. HINES: Yeah, that's a good question, Commissioner Kolbeck. What I see, all utilities are trying to provide the best product possible to their customer base. And certainly low costs is one of the foremost drivers of a product that they can provide to that customer base. When you are evaluating resources, that is one of your primary concerns. You are also taking into account the risk associated with fuel prices, that sort of thing, environmental risks, and they all factor into it. But mandating an outcome as opposed to allowing for the planning process to work its way through I think gets away from the discretion that's necessary at the utility level, which I do think is being implemented.

COMMISSIONER KOLBECK: Thank you.

VICE-CHAIR HANSON: Commissioner Johnson.

CHAIRMAN JOHNSON: To what extent, Mr. Hines, do you think that diversity, fuel diversity, while it may have the effect of raising costs, dampens volatility or dampens fuel price risk and is that a tradeoff that would make sense from a public policy perspective?

MR. HINES: Commissioner Johnson, it certainly depends first of all on the type of fuel diversity you are looking at. If you go to resources that don't have a fuel component, like wind, you do dampen to some extent the flexibility that occurs because of volatile energy markets. But we -- in Montana we have probably about eight percent of our energy needs right now being served through wind and that in itself is creating issues which have to be addressed by buying additional resources that use natural gas, for example, which creates some of that instability that you are trying to get away from. And there's a balance. Even with more stable prices, you have to compare that then to the benefit of having lower costs, the probability of lower costs versus price stability.

CHAIRMAN JOHNSON: Is it too simplistic to say that NorthWestern's fuel mix comes with coal being almost completely the base load source of power, of electrical generation, and that natural gas is almost completely a peaking resource?

MR. HINES: Over 90 percent, 95 percent I think is the number of the energy component comes from coal generation, and that small increment, maybe 600 hours a year or whatever comes from the natural gas, so I don't know if simplistic is the right term, but those are the numbers that reflect our operations.

CHAIRMAN JOHNSON: Does that picture really show a very diversified mix, a generation mix for a company like NorthWestern? And while I acknowledge that in the past that that's made perfectly good sense, NorthWestern has been a responsible utility from all accounts with regard to its generation mix in South Dakota, but from a forward-looking perspective, does having that kind of a generation portfolio bring additional risk onto a utility and its ratepayers?

MR. HINES: Commissioner Johnson, I guess I look at the type of risks that are likely to occur in the future and especially as applicable to coal, one of the first things that comes to mind is some sort of national CO2 requirements. Before I would be willing to go down the path of saying, well, you need to diversify to mitigate that risk, one of the first things I would look at is what are the cost implications of a CO2 tax? And it could be likely that the CO2 tax on top of the coal generation is still less than the costs associated with alternative fuels. It may not be. But I think you would want to make that determination before you make a requirement.

CHAIRMAN JOHNSON: Thank you. Commissioner Hanson, that's all I have at this time.

VICE-CHAIR HANSON: Thank you. Mr. Hines, you touched on a -- I appreciate the explanation at the beginning, especially pertaining to affordability and reliability, as you touched on those and those are two areas that the commission is keenly interested in. Would you say that a standard would have -- could potentially have a favorable impact on reliability?

MR. HINES: Once again, I'm speaking now from the Montana portion of NorthWestern where we have been through legislative requirements, been forced to expand our portfolio and not necessarily in a way that the utility planning would end up in. I think that both from a reliability, especially from a reliability perspective, we have had difficulties integrating the amount of wind we have been forced to integrate into our system. The transmission side has violated some WCC standards of being within a certain range on the transmission side on 10-minute intervals and we have had to go out and then acquire significantly more regulating resource in order to bring our reliability back into that range, necessary range.

VICE-CHAIR HANSON: You stated the percentage of wind and I didn't catch that as you said it.

MR. HINES: It's 135 megawatts on a 1.1, 1,100-megawatt system or around eight percent on the energy side, around 450,000 megawatts a year.

VICE-CHAIR HANSON: The literature that we have been exposed to provides that or states that in the area of about 30 percent wind integration becomes extremely difficult, 20 percent is challenging, and you are saying that eight percent is difficult?

MR. HINES: They are almost different questions. Is the system able to integrate it at any cost? That's almost I think where the 30 percent type of numbers are coming from. We are finding we can certainly integrate at eight percent, but it's the ancillary costs associated with insuring that product integrates into our system have fairly high costs and the increment of adding additional wind into our system, for example, will have even greater incremental costs. Basically we have tapped out the ancillary services market from what we have seen through RFPs and we will have to go to green field, building new generation authorized to integrate that into our system. I guess to be clear, there's technical feasibility and then there's economic feasibility.

VICE-CHAIR HANSON: Thank you. Is NorthWestern's portfolio diversification typical of a Midwest utility?

MR. HINES: I'm sorry, I can't really answer that precisely. I don't know if anyone else is able to, but speaking to other utilities' portfolios, I'm not real familiar with them.

VICE-CHAIR HANSON: I was asking because I thought I knew the answer and I wanted to see whether you did.

MR. HINES: I can nod if you tell me. (Laughter)

VICE-CHAIR HANSON: Going back just a little bit, we were discussing multijurisdictional utilities and effects on -- to an extent, we didn't quite address reliability until later. However, with 23 different states having 47 different RPSs and having moving targets of RPSs, I'll try not to editorialize, would it be -- would it not be better to have a standardization so that utilities could function -- I'm recognizing that I shouldn't be marrying RPS to the question -- but with different standards in different states, would it not be better coordination and less administrative challenges to utilities if there were similar standards, synchronized standards?

MR. HINES: One benchmark that utilities are judged by is the price that they provide to their consumers and having different standards in different states certainly influences the rates that are provided to those customers, and having some sort of equal applicable standards across all of the jurisdictions would at least level that playing field. From a reliability perspective, it still would be a function -- if you have a significant portion of your portfolio being provided through hydro, you are able to integrate wind a lot more easily than if you have a significant amount of your resources provided from coal, for example. The ability to ramp up coal plants on a minute by minute or 10-minute intervals is significantly less than a hydro or natural gas type of portfolio.

VICE-CHAIR HANSON: So piggybacking on that answer, without having you elaborate to any great extent, do you see administrative challenges with this type of standard being implemented?

MR. HINES: I'd say less administrative than I am trying to avoid what I think from a planning perspective isn't in the best interest of consumers, and there's certainly some additional requirements from an administrative perspective, but I would place my weight more on potentially implementing resources that really aren't in the best interests of consumers.

VICE-CHAIR HANSON: Thank you. Does staff have any questions?

MS. WIEST: I just had one question, then. If the commission were to adopt such a standard, do you have any opinion on how long such a plan, the period should be for, the time frame?

MR. HINES: With the caveat that we prefer not having such a standard adopted, I think a five- or 10-year plan, probably a 10-year outlook with a renewal every four or five years would be something more easily from an administrative process to be put forward as opposed to something every year or every other year.

MS. WIEST: Okay, thank you.

MR. RISLOV: Good afternoon. If you weren't going to use coal for base load fuel, what would be your realistic option or options?

MR. HINES: I'm extremely concerned about the volatility in the natural gas market for a base load resource. I would probably -- one of the first things I'm interested in right now is seeing if you can't get some sort of syn fuel out of the coal product, so you get some of the environmental benefits from natural gas while at the same time lessening the volatility of serving the base load from natural gas, so you are combining a little bit of the benefits from both sides.

Technologically there's still some concerns associated with where we are on the technological curve there, but over the next I think one to five years, we are going to have some more plants built using those sort of facilities and I think we will have a greater certainty for financing.

MR. RISLOV: Thank you.

VICE-CHAIR HANSON: Mr. Hines, do you think from a standpoint of renewables, in your own opinion, do you think that a standard would have a positive, negative or little or no effect on establishment of additional renewables?

MR. HINES: Certainly, Commissioner Hanson, any sort of standard will create an industry, if that's where your question is going, for renewables. If there is a guaranteed purchase, there will be guaranteed suppliers.

VICE-CHAIR HANSON: Commissioner Johnson asked a question, I believe he used the adjective dampen when he was asking a question regarding price risk, and as I said at the beginning, we are very concerned about affordability and reliability and I had a question, I was trying to ascertain whether or not to get a little bit more clarification on the potential negative economic impact to consumers from a standard. I was thinking of a word exacerbate as opposed to dampen, but that's something that we are very concerned with. Could you elaborate a little bit more on it?

MR. HINES: I can talk to you a little bit about what we are seeing in some RFPs right now for both wind and where we are seeing some of the construction costs coming in on some new builds of coal, and it's interesting the effect that these RPS standards are having across the country, especially on wind. The demand for turbines has shot up incredibly.

When we bought 135 megawatts, so 100 turbines three years ago, the price was around $30 a megawatt hour just for the turbines themselves. I don't think you can find a price under $40 for a turbine right now. And that's assuming that you can obtain the turbines, unless they are retrofits or refurbished. New turbines are exceedingly difficult to obtain. And I've talked to some suppliers where they are saying unless you are doing a very large wind plant, they are not even interested, so if you are trying to do 10 megawatts, 15 megawatts, it's extremely difficult.

So if you are talking $40 there at a minimum, we are seeing just local property tax, those sort of things are about another five or six dollars, and then we are looking at firming costs, existing firming costs around four or five dollars, but green field firming costs in the $15 range. So you are in the mid fifties pretty easily on renewable and that's about where we are seeing a brand new coal plant coming in as well.

VICE-CHAIR HANSON: That's surprising. I think it surprises all of the commissioners that government intervention somehow is a negative impact on private enterprise. (Laughter) That's all the questions I have. Thank you very much. Anyone else with any questions? If not, our next presenter --

CHAIRMAN JOHNSON: It might be worth noting for the reporter that we have that your tongue was firmly planted in cheek.

VICE-CHAIR HANSON: Thank you. A smile doesn't come over to the transcriptionist. Our next presenter is Alan, and he will correct me on his last name, Welte.

MR. WELTE: Right.

VICE-CHAIR HANSON: He is director of generation for MDU. Welcome.

MR. WELTE: Thank you, Commissioners. I appreciate the opportunity to speak to you on this matter this afternoon. Just a little bit about myself. My main responsibilities for Montana-Dakota are over the operation of the existing generating facilities and not the planning of new facilities.

I guess we have already read the paragraph from the standard. Just a little bit of background about MDU. The red area on this map represents MDU's electric service territory. You can see we operate within four states. The black dots represent MDU's electric generating facilities. You can note that the Coyote station in central North Dakota and the Big Stone station in South Dakota are joint-owned facilities of which we own a piece and are operated by Otter Tail. The load served in northwest Wyoming are served by -- through a power purchase agreement with Black Hills Power and Light.

You can see our mix of load within or the generation within the four states. The totals by state would be 221 megawatts in North Dakota, 104 megawatts in South Dakota, 155 megawatts Montana. The Montana generation will soon increase by another 19.5 megawatts as we would install a wind farm in eastern Montana. Additionally, as you are aware, MDU is a participant in the proposed Big Stone Unit II, it's a high efficiency 630-megawatt power plant, of which we would own approximately 122 megawatts. You can see that both the load and generation cover a large integrated geographical area for MDU.

The design of technologies for MDU's existing generation effectively define its generation fuel mix. MDU does not have any nuclear or hydroelectric facilities. The current fuel choices in the region are coal, natural gas, fuel oil, and renewables. Of the current generation total, 25 percent is fueled by either natural gas or fuel oil and the remaining 75 percent is fueled by coal. MDU has interests in renewables. We have recently signed an agreement for an equipment contract for a 19.5-megawatt wind farm in eastern Montana. MDU is in the final stages of securing land leases and we anticipate this generation to be in operation by year's end.

Our previous efforts in the renewable area began in 1982 where we performed a demonstration project to interconnect a small wind project to a distribution system. Since that time, we have had two individual contracts in place to build a 19.5-megawatt wind farm and an additional 30.5-megawatt agreement, both of which expired before the construction was initiated.

The design technology diversity of MDU's existing generation define its fuel mix. These include cyclone, fluidized bed, stoker and pulverized boilers as well as combustion turbines of frame and aero derivative design. Diversity also exists in the methods of transporting coal from the mine to the generating facility. This has become increasingly important in the current climate of shortages of railroad resources, railroad congestion, and the captive shipper related pressures on cost of transportation. Of the generation of -- of our generation fueled by coal, 28 percent is fueled by unit train, is delivered by unit train, 28 percent is delivered by short-haul train, 15 percent by over-the-road trucking and 29 percent is mine mouth and delivered by conveyor. So we have diversity in our delivery within the coal generation.

MDU employs the use of integrated resource planning. Under the IRP process, generation fuel type is objectively determined through the application of supply side resource planning principles to determine the best cost resource. MDU's IRP process not only examines costs but also considers factors such as avoiding heavy reliance on gas-fired generation and the associated price and reliability risk, the availability of energy to serve retail load versus reliance on the MISO market, and also the ability to sell surplus energy at times into the MISO market. Other things include the availability of resources to meet our economic development efforts, and finally, the employment of renewable resources, which are a higher cost on a strict cost comparison basis.

Just as Mr. Hines has indicated, MDU's service territory is located in the middle of large coal reserves, in the middle of a large area of natural gas reserves and in an area with significant potential for wind development. Cost effective future supply will come from these regional sources, we believe.

In summary, within this universe of regionally likely fuel choices, least cost planning will drive resource optimization of fuel choice. There is no good reason to depart from the existing standard for determining generation resource choice and corresponding generation fuel mix. It is MDU's position that you should not adopt the fuel diversity standard. This concludes my remarks.

VICE-CHAIR HANSON: Thank you very much, Mr. Welte. I suspect you will have the opportunity to answer similar questions as Mr. Hines did. Questions by commissioners.

CHAIRMAN JOHNSON: You know, you are talking about some of the diversity, other than fuel diversity, strict fuel diversity, some of the diversity MDU had with regard to where its coal came from, for instance, and that reminded me of a story. I was with two friends, one was from New York and one was from a small town in Iowa. The friend from New York asked my friend from Iowa, is your small town very diverse? She said, yes, we have Norwegians and Swedes.

And I do think it is worthwhile to note, though, that we sort of think of fuel diversity as the mix of the five main fuels that companies have, but certainly technological diversity or sort of coal supply diversity is also important as we look at some of these cost drivers. Are there any other things like that that you think act as a bit of a hedge against volatility and how MDU runs its operations?

MR. WELTE: Certainly within the technology area, our plants have a lot of diversity in regard to, for instance, their needs for water. We have power plants that take circulated water from the river. We have plants that use closed cooling tower systems. We have one plant that has a lake, if you will, to provide that need. And there are other distinctions specifically with each of our plants that give them diversity.

And certainly regarding the risk associated with coal, it was talked about earlier, our plants are fired by a combination of lignite and Powder River Basin fuel, so we have some diversity within the constituents of the coal itself.

CHAIRMAN JOHNSON: Commissioner Hanson, if I could. Do any of the other states that MDU does business in, do they have any other fuel diversity standards, including an RPS or anything else that would affect how you build out your generation resources?

MR. WELTE: Certainly, as was mentioned by John, the state of Montana has an RPS standard, which is one of the drivers why we are currently installing the 19 megawatts of wind in Montana. North Dakota, I believe the legislature just concluded and I believe there is a guideline that we'll be reviewing in the future.

VICE-CHAIR HANSON: Commissioner Kolbeck, it looked like you were cueing up a question.

COMMISSIONER KOLBECK: Thank you, Commissioner Hanson. This right here, the generation fuel diversity, could you walk me through what those are? I guess I trust you that they are diverse, but exactly what is each one of those? Just a one second or two second deal.

MR. WELTE: Sure, what I'm highlighting here is that our coal-fired power plants have multiple methods of combustion, basically cyclone, fluidized bed, stoker, and pulverized units are all different types of boilers, if you will, and have different methods of combusting the air in coal. I also mentioned we have different designs within our combustion turbine fleet, simple cycle, heavy frame units, and also we have a high efficiency newer aero derivative type of generating unit there.

COMMISSIONER KOLBECK: I'll ask you the same question as I asked Mr. Hines. Do you feel that as a whole the industry embraces this fuel diversity without mandates or do you feel there are some -- obviously in government, the actions of some few may ruin the greater good, you know how that goes, but do you think that as a whole the industry is abiding by these fuel diversity clauses voluntarily without mandate?

MR. WELTE: Certainly I think our resource planning process within the regional realm and fuel choices that we have, I believe we are attempting to be as diverse as possible.

COMMISSIONER KOLBECK: Thank you, Alan. Commissioner.

VICE-CHAIR HANSON: Staff have any questions at this time?

MS. WIEST: I just had a question on your IRPs. Do any of those have to be approved in any of the other states?

MR. WELTE: Have to be approved?

MS. WIEST: Are they approved at all or do you just develop yours?

MR. WELTE: I guess I'm getting a nod that says no, we do not have approval.

MS. WIEST: Then the same question I asked Mr. Hines, is if the commission were to adopt such a standard, do you have a time frame that could be applicable to the standard?

MR. WELTE: If they were adopted, I don't see any reason for the standards to be on a time line different than our existing planning process for a 10-year horizon and with periodic renewals or reviews of those.

MS. WIEST: Thank you.

VICE-CHAIR HANSON: Any further questions? If I could ask just a few quick questions pertaining to affordability and reliability and administrative challenges and the like. The first question is pertaining to any administrative challenges you might see from implementation of such a standard. I recognize you are in generation, but do you see challenges of this nature for you?

MR. WELTE: I guess the thing that comes to mind is the concern I would have over cross jurisdictional requirements and the administration that would go along with that. We operate in four states, if we had multiple standards, if you will, it would create some problems for us administratively. Also it would create some uncertainty and possibly some problems in regard to financing of large projects and so forth relating to delays or whatever would come from that.

VICE-CHAIR HANSON: From a reliability standpoint, do you then see benefit from a standard in generating electricity as opposed to -- since there is implementation in various states for RPSs, et cetera, do you see that if there was a standard, that it would be easier for MDU to provide reliable service as opposed to not having a standard?

MR. WELTE: I think I would answer that question similar to Mr. Hines in that if the playing field was even in regard to, for instance, the view of renewable generation, that certainly would take -- have the possibility of taking some risk away, but from a reliability standard or reliability concern, I guess I would have less understanding regarding, for instance, the implementation into the transmission system of large amounts of, for instance, wind or other renewables. So I guess I'm not sure I can speak towards that.

VICE-CHAIR HANSON: Thank you very much. Does anyone else have any further questions from the commissioners? If not, we very much appreciate Mr. Welte and Mr. Hines, that you accepted our invitation to come here today and make a presentation. We appreciate the information that you have provided to us.

We are a few minutes, perhaps not a few minutes ahead of time. It looks as if we may be. We will start our next presentations at approximately 2 p.m., we will call it on the hour, 2 p.m., and that will be the fossil fuel generation and efficiency. Thank you, Mr. Hines and Mr. Welte. There's time for a short break for folks.

(Whereupon, the hearing was in recess at 1:53 p.m., and subsequently reconvened at 2:01 p.m., and the following proceedings were had and entered of record:)

CHAIRMAN JOHNSON: It is 2 o'clock. We are ready to start our third session today, this one dealing with the efficiency of fossil fuel generation, and again Commissioner Gary Hanson will be moderating this session. Commissioner

Hanson.

VICE-CHAIR HANSON: Thank you very much, Mr. Chairman. As with the previous standard, the EPACT also requires the commission to consider an adoption of a fossil fuel generation efficiency standard. The standard provides that each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

With us this afternoon for the presentations are Mr. Alan Welte, who is still the director of generation for MDU, and Mr. Jeff Endrizzi, the plant manager of Otter Tail Power Company from Big Stone plant. Our first presenter will be Mr. Welte.

MR. WELTE: Thank you, Commissioner. Montana-Dakota's need to meet its customer load requirements as efficiently as possible and the participation in the Midwest Independent System Operator, MISO market, basically drive our company to wring out any available efficiencies we have available in our existing fleet.

Montana-Dakota has had a long history of making incremental improvements in efficiency through modifications of equipment and also operational or procedural changes within our operations. Some of these projects include the conversion of our R.M. Heskett Station Unit II to what's called a fluidized bed boiler or combuster, installation of the Glendive Unit II LM 6,000 aeroderivative combustion turbine, the addition of evaporative cooling on our simple cycle older combustion turbines, the replacement of process controls and actuators at nearly all of our coal-fired plants, turbine component modifications and retrofits, generator excitation system replacements, the installation of what's called variable frequency drives on motors that drive fans and pumps, coal blending, ongoing research projects through the participation in technology studies such as our participation in the lignite technology development work group, and other projects at our coal-owned facilities, which I'll allow Otter Tail to describe.

Energy efficiency in generation is usually measured by what we call heat rate. This is the amount of energy needed to produce one kilowatt of electricity. In the case of combustion turbines, the heat rate is largely fixed by the design of the installed unit. In the case of coal-fired units, the heat rate is largely determined by the boiler design and the choice of coal. We have seen some success in making modifications to use subbituminous coal and blends of subbituminous coal and lignite as well as some modifications to our turbines. But large efficiency improvements are limited by the original design of the unit.

Over the past 20 years, through these efficiency improvements and continued operation of an aging fleet at high capacity factors, MDU has improved the combined heat rate of our units, of our mix of units by about.14 percent per year.

So with an aging fleet, we have seen an improvement, continuous improvement of our heat rate, demonstrating that we are looking out for efficiency. The search for more efficiency, more efficiencies in existing coal-fired generating resources can also be constrained by regulations of air emissions under laws within individual states where the plants are located.

Modifications to existing generation resources often trigger or threaten to trigger Environmental Protection Agency new source performance standards. These standards may require uneconomical, large capital expenditures for pollution control equipment, even if the amount of new generation or the efficiencies gained are very small, so there's risk in that area.

In summary, operating efficiencies through economical projects has and continues to be a practice for Montana-Dakota Utilities. Large efficiency improvements are limited by the original equipment and coal designs. Environmental regulations preclude some efficiency projects or make them uneconomical, and then the integration -- the integrated nature of our electric systems across several jurisdictions must also be considered. MDU's position is that the commission should not adopt a fossil fuel generating efficiency standard. Thank you.

VICE-CHAIR HANSON: Thank you, Mr. Welte. Are there questions from the -- by the commissioners?

CHAIRMAN JOHNSON: You know, I understand -- I think this is an interesting standard because it seems to me there are already some market forces in place that would make companies want to do this to the extent that it was prudent. It seems to me this is also standard practice for a lot of utility companies out there. So I don't know that I see a lot of benefit to the standard. I'm not sure I see a lot of drawback or disadvantage or potential harm to the utility or the ratepayer either, provided that the commission were to insure that any steps taken were prudent. What's your opinion on that, Mr. Welte? All the standard requires is that you, that the utility companies have a plan to improve their efficiency over a 10-year period. Thoughts.

MR. WELTE: My first thought is that because we are already doing these things, it's not necessary. But the other thoughts I would have is there are concerns that I would have regarding the cross jurisdictional areas, the differences between states, and MDU as well as Otter Tail participate in joint-owned units. We also have -- we also have decisions that we would have to make with multiple companies and as we look at the installation of future base load units, the numbers of participants increase and it makes it more complex to reach agreement on what those efficiency improvements would be and how those costs would be recovered.

CHAIRMAN JOHNSON: That's all I've got.

VICE-CHAIR HANSON: Thank you, Commissioner Johnson.

Commissioner Kolbeck.

COMMISSIONER KOLBECK: Yes, thank you. I was just wondering what your opinion is if -- you are a multistate company. What do you think one state adopting the generation efficiency plan and the other state not, do you see that as not necessarily for the company, but for the state, would you see more efficiency go one way or the other or would it be just a company process? Does that make sense?

MR. WELTE: If I understand your question correctly, I would see concern as an investor-owned utility with the risk of recovering the costs of those efficiency improvements within the various jurisdictions where we serve.

COMMISSIONER KOLBECK: Well, let me put it this way. Hypothetically, if there was to be a coal plant in South Dakota and a coal plant in North Dakota, would one plant operate more efficiently in North Dakota than it would in South Dakota if, say, North Dakota adopted these, this plan, would that drive internal processes in your company to make maybe more leaps and gains in another state than our state?

MR. WELTE: Certainly if there was a more stringent standard in one state, we would have to try to abide by that. I guess the answer would be yes over time.

COMMISSIONER KOLBECK: Because it would be developed -- each electric utility shall develop and implement a 10-year plan. Do you get what I'm getting at? If we didn't do it and someone else did, would we be behind the eight-ball or would we have dropped the ball in some way by not requiring the company to do this?

MR. WELTE: A different state may be the beneficiary of mandate in a different state on a unit that would be used for serving customers within different locations, I guess.

COMMISSIONER KOLBECK: Now, I'm sorry, Commissioner Hanson. One more question. The replacement of these controls, motors and pumps that you would do, is this a yearly thing, a five-year plan? Is it something that you amortize out? Is it something that they have a certain life span on?

MR. WELTE: Yes, we would have a justification process and a long-term planning process that would be used to evaluate whether those projects are viable, looking at a number of facts and costs related to the investment costs and also their impact on the operational costs of the facility.

COMMISSIONER KOLBECK: Thank you, Alan.

VICE-CHAIR HANSON: Commissioner Johnson.

CHAIRMAN JOHNSON: I just wanted to seek additional clarification on an answer you had to Commissioner Kolbeck 's question. In the scenario he described, it wouldn't be likely that South Dakota would be behind the eight-ball because generation resources aren't jurisdictional. Just because something is in North Dakota and is more efficient or less efficient, those benefits or costs in many cases could flow to

South Dakota ratepayers as well. That's a bit of a presumption on my part, I'm happy to say I haven't been through a rate case with MDU, but perhaps you could let me know where I'm wrong or clarify your answer.

MR. WELTE: I believe you would be correct in that assumption. I don't believe we have filed a rate case in South Dakota since 1986 or 1987, which is also, I believe, an indication of our efforts to keep our plants efficient.

VICE-CHAIR HANSON: Thank you, Mr. Johnson. Excuse me, Commissioner Johnson. Mr. Welte, twice during your presentation and presently on the slide it has a bullet point, you made reference to environmental regulations. This particular one stated that environmental regulations preclude some retrofitting and seems to imply that the costs of required environmental upgrades discourage fuel diversification. Is that what you are intending to say, that fuel diversification is affected by -- I'm going to have to rephrase the question because it appears that --

MR. WELTE: I don't think I'm saying specifically fuel diversification, but possibly modifications to equipment that could involve fuel, fuel-related items.

VICE-CHAIR HANSON: Perhaps I should take it step by step. The EPA, there are required environmental upgrades when, for instance, an older coal plant is converted, some changes are made, and I believe you have to spend a certain amount of money prior to it triggering. But those required environmental upgrades, the cost of those, as I understand it, correct me if I'm wrong, discourage certain conversions; is that accurate?

MR. WELTE: Yes, that would be accurate. There's a great deal of uncertainty even in modifications to our plants where we feel that we are abiding by what we call new source review rules, of which you mentioned one, a factor of the percentage of the cost of the investment and so forth. There's a lot of uncertainty even when we have taken those projects before the health departments and so forth, there's still risk of lawsuits and differences of interpretation of whether or not those projects would be required to meet what's called new source performance standards. And if they do trigger new source performance standards, that would be the point where we would be required to make additional modifications to bring the entire units, the entire unit up to a different level of emission standards. It may not necessarily be directly related to the project that we were trying to conduct and had an efficiency improvement in mind.

VICE-CHAIR HANSON: Thank you for answering. I'm not attempting to be a proponent or opponent, I was attempting to dissect the statements that you had made, and I see our analyst, Steve Wegman, has brought up the regulation of air emissions under laws in states where a power plant is located, Environmental Protection Agency's new source performance standards. I was attempting to get at the -- at exactly what you were attempting to say there and correct me if I'm wrong. It appears that you are saying that fuel diversification, which is the subject at hand, is discouraged in making the conversion because of the high costs of environmental requirements, adjustments that have to be made if a modification is made for that fuel diversification.

MR. WELTE: Well, Commissioner --

VICE-CHAIR HANSON: Is that what you are trying to say there?

MR. WELTE: Not exactly. In this section we are trying to discuss the items that would preclude us from making efficiency modification to a plant as opposed to strictly a fuel-related diversity type of modification. So to clarify our comments in this area, we are saying that a mandated or a standard within one state that would target a certain percentage of efficiency improvement might require us to do something or modify some piece of equipment that would put us at risk of not meeting environmental rules, which would in the secondhand cause us to be subject to adding additional pollution control equipment.

VICE-CHAIR HANSON: Thank you. The rule that we are required to consider states that develop and implement a 10-year plan. Do you wish to comment on the 10-year plan versus a different duration? Five-year, two-year, 30-year?

MR. WELTE: Certainly I think a five- or 10-year plan is what most utilities would already be using as a horizon for implementing those types of efficiency projects.

VICE-CHAIR HANSON: Thank you. Do you see any -- I will jump back. You had mentioned coal blending. What type of coal blending do you do at the present time?

MR. WELTE: Sure. At our R.M. Heskett station in Mandan, North Dakota, to achieve efficiency in the combustion process, we blend lignite with a little bit of Powder River Basin coal.

VICE-CHAIR HANSON: You are not blending -- well, that will suffice. Thank you very much, Mr. Welte. Does anyone have questions at this time?

COMMISSIONER KOLBECK: Thank you, Commissioner Hanson. You confused me. Just back to what Commissioner Hanson was trying to get at there. I just wanted to make sure I understand this. Are you saying that if it costs X amount of dollars to burn one pound of coal, would you want to burn more coal to offset the new and added costs? Is that kind of what you are getting at, environmental mandates would make it more expensive to burn coal so you would want to actually make up those costs by maybe burning more? Is that kind of what you are getting at? No?

MR. WELTE: No, I don't think so.

COMMISSIONER KOLBECK: I just wanted to make sure that wasn't it.

MR. WELTE: No.

COMMISSIONER KOLBECK: For some reason, in my mind I was thinking obviously if it costs you one dollar to burn one pound, if you could burn two pounds for one dollar, that's what you would want to do.

MR. WELTE: No, I think what I'm saying, Commissioners, is that environmental requirements that would come into effect because of an efficiency project, the cost benefit of that project could turn to be an uneconomical alternative once you would consider the additional pollution control equipment that would be required.

COMMISSIONER KOLBECK: Thank you.

VICE-CHAIR HANSON: Thank you, Commissioner Kolbeck. If there are no further questions, we will allow you to take a respite and Mr. Endrizzi from Otter Tail Power Company, appreciate your being here. You have the floor.

MR. ENDRIZZI: Thank you, Commissioners. Thank you for spending some time and allowing me to discuss power plant efficiency improvements at the Big Stone plant. Big Stone is South Dakota's largest fossil fuel fired generating facility and I am the manager of that facility. I have been at Otter Tail for 17 years. I have had three different jobs at Big Stone, plant engineer, engineering supervisor, and now plant manager. However, my job has not changed from day one. My job with Otter Tail is to economically and reliably produce electricity and that is what I have been doing for 17 years. We continue to do that.

VICE-CHAIR HANSON: While you are getting ready there, I neglected in my duties. I understand you brought copies of the PowerPoint and left some in the back there. If some folks in the audience wish to access those, those are available to you. Forgive me for interrupting you.

MR. ENDRIZZI: A little background on Big Stone plant. We are a 460 net megawatt unit, it produces 3.6 million pounds per hour of steam flow. We are co-owned by Otter Tail Power at 54 percent, NorthWestern Energy at just over 23 percent and MDU just under 23, and we went into commercial operation in 1975. It is not uncommon for smaller utilities to have co-ownership of large generating facilities. It really depends on the economics of each company at the time, but in 1975 or leading up to that, none of our utilities were ready to build a large facility on our own, so we shared that.

That end result when we started operating those units really provides a system of checks and balances. As each company might have its own financial things going on at any given time, any given year, it really does give a good set of checks and balances for the projects that we choose to do. Ultimately what that results in we believe we end up doing the right thing a lot more frequently because of that.

Big Stone's mission statement really fits in with that philosophy. We exist to safely generate electricity reliably, economically and in an environmentally responsible manner. I will give you a little bit more information on cost. Now, I realize that graph is a little tough to read. Don't worry about the numbers on the side. Really we are looking at the trends. This is our fuel cost information going back to, oh, 1991. Big Stone plant was designed to be a lignite-fired facility and we had a 20-year contract from 1975 to 1995, and that's over obviously on the left side is 1991, and in 1995 we switched to western subbituminous fuel predominantly out of Montana and had a significant price break at that time.

And in the year 2000 we had to switch over to a Wyoming fuel, that's a little bit cleaner from an SO2 or sulfur content standpoint. But you can see from where we started at about a $1.15 per million BTUs, dropped down to about 90 cents, and last year we were about $1.50, so large increase in the price of fuel in the last 10 years. We saw a significant savings when we moved away from the lignite.

To offset these rising fuel costs, one of the things the plant can do is work on efficiency of the unit, let's try to burn less coal per megawatt. Alan talked about the heat rate, it's measured in BTUs per kilowatt hour. The lower the number, the better the plant is operating. The first drop that we see, that's the black line in about '95. '96 is when we switched from the North Dakota lignite to a western subbituminous. It's a much better fuel from a plant performance standpoint, a lot lower moisture, and we operated fairly stable on heat rate for the next number of years. Did a few projects in there to maintain that and then the dropoff, actually in 2006 we had a record low heat rate. We have done some projects, we will talk about those further in my talk. But to have a record low heat rate or the best performance after 31 years of operation tells us we are doing a lot of things right.

There are a few things that we do at the plant to try to control that heat rate. One are just the improvements are there primarily to minimize our costs for our customers. We have some operational practices, one of them being the fuel switch in 1995, but also some operation or yearly practices, cleaning equipment for optimum heat transfer, and then the other side of that, Alan touched on those, too, at the other facilities, capital improvement projects. These are physical changes to the plant, and we do many of these, have done many of these over the years, substantial dollars, substantial improvements. Turbine replacements, boiler modifications, control system replacements, other replacements.

Let's take those piece by piece. The Big Stone plant, like I mentioned, was designed to burn North Dakota lignite. That's a low BTU, high sulfur fuel. We have also experienced a lot of load limitations due to that fuel. When you burned it, the ash would foul the boiler, make it physically dirty, you couldn't get the heat transfer from the flu gas to the steam, very inefficient. We would have to shut down the plant a couple times a year and do some cleaning. We had a 20-year contract on that lignite, 1975 to May 1995 and then we had some makeup tons in there we had to also burn, but by August of '95 we were out of that contract.

At that time we switched to the western subbituminous. At the time we made that switch -- well, in the lignite days, I think the anecdotal evidence says that Big Stone plant was the only lignite-burning plant that rail hauled their fuel any distance. We decided to build a plant in northeastern South Dakota, were pulling the coal from western North Dakota and rail hauled that. That fuel was 42 percent moisture, we should have been using tanker trucks. Just not the best fuel.

And a lot of plants at the time, due to environmental reasons, were switching fuels from, say, eastern fuel to the western fuels. They viewed that as a downgrade. We saw that as an upgrade. We were able to burn a better fuel and not have the problems that we had with the lignite, so moving fuels was really a no brainer once we got out of that contract.

Some of the things that we did experience, five percent efficiency improvement on the boiler side. Very significant. That's really driven by the lower moisture. The subbituminous we are burning today is closer to 30 percent moisture. Huge improvement. Environmental improvements. SO2 on lignite was about 2.4 pounds per million BTUs. The switch to the Montana fuel in 1995 dropped that in half to about 1.2 pounds per million BTUs, and in 2000 we also had to make a further switch down to Wyoming fuel and dropped that SO2 to about .75 pounds per million BTUs, so from 2.4 to .75 on an SO2 basis.

The NOX emissions did increase slightly due to the design of our boiler. We have a cyclone boiler, that offers a lot of fuel flexibility. A cyclone boiler is different from a pulverized unit. It allows us to burn bigger particles, that's why we have -- we burn some tires and some seed corn, different things like that, but the design of that creates high temperatures in the combustion zone and you create some combustion NOX, so the NOX actually went up from about .7 to 1.2. We do have control technologies that have been in place since 1998 and have dropped that NOX back to about .8.

One of the operating issues we did have with a fuel switch, we did lose some steam temperature. When you don't have that moisture in your fuel, the mass flow in the boiler is lower and the thermodynamic laws of convective heat transfer say if you have less mass, you can't transfer as much heat over to the steam, so we had to add boiler surface in the back end of the boiler to get the steam temperatures back up to where we belonged.

We have had some minor projects that went along with that. As we redesigned the boiler, we were able to rewind a large 4,000 horsepower motor down to 2500 horsepower and operate that at more -- a much more efficient point on its operating curve. So those types of things have been ongoing.

At the same time we switched fuels, we were able to rebuild our coal dumper building. We bring in coal by unit train and rotary dump that over into our storage system. Aluminum cars at the time were receiving a 70 cent a ton discount on the delivery price, so that was very substantial, that helped us justify that project.

Some of our operational practices. I mentioned the cleaning of equipment. The boiler being a large heat transfer surface, you get ash built up on the heat transfer surfaces, the tubes. We have to go in and high pressure water wash that. We do that about once a year. On lignite we were doing that twice a year. The other items, air preheater high pressure wash and condenser cleaning, those are both also large heat exchangers. We go in and on a semi regular basis need to go in and keep those clean for optimum performance.

This is where really I believe the point of the proposed standard or standard we are discussing really falls into place, the efficiency improvements for capital projects. Big Stone plant has a fairly substantial history of trying to control heat rate through equipment improvements. First one of any significance was the 1996 low pressure turbine replacement. You will see some of the large dollar values we are talking about in any of these projects.

Again, when we justify our projects as engineers, we try to get them justified and approved by our co-owners, we are looking at reliability issues and also efficiency to help pay for that. We really need to stay ahead of the game. The low pressure turbine really was a lemon, no way to sugarcoat it. It was just a lemon. Several or many of those are in operation across the country. It's a Westinghouse Building Block 73 for those who need the details, but most units that had that operating as a single low pressure turbine had numerous, numerous blade failures over the years. Those things were not designed very well. And I don't believe there are any single Building Block 73 turbines left in operation.

We were able to replace that, that piece of equipment and get a two percent plant efficiency improvement. The low pressure turbine does about half the work of the turbine train. That really is the work horse, and we were able to improve overall plant efficiency by two percent by doing that and also extend our inspection intervals up to 10 years. We used to open the turbine up every five years and cross our fingers, hope we didn't find anything wrong. This unit was opened up, it was nine years it fell into our overall cycle, there wasn't one thing wrong with it. So the technology has changed over the years and we are able to capitalize on that.

Very similar story with the high pressure turbine, much higher dollar value for that project. We also have seen about a two percent increase in efficiency. We have more capability waiting out there for us, but that would require some boiler modifications. Those boiler modifications would allow us to burn more fuel than we burn today on an hour-by-hour basis. We aren't able to do that without tripping a new source review situation. That's the kind of thing that we were discussing with Alan. We will talk about that a little bit later.

Some other projects we have done, we replaced our entire plant control system with distributed controls, electronic controls back in '96 as well. It improves the reliability of the operating unit and we did see a minor improvement in heat rate and efficiency just by holding the operating level of the plant more steady and more stable. Compare it to driving down the highway at a nice steady pace with your cruise control versus up and down without and which one is more efficient. We were able to do that with the plant.

We have got several other smaller projects in addition to the ones that Alan named. We have done things like replace smaller heat exchangers, retube condenser, predry system removal. When we burned lignite, we had to drive off moisture before we could burn the fuel and that was another step in the process. With the western subbituminous, we don't need to do that anymore.

This next chart, couple different reasons for this one up here. Before our fuel switch in '95, Big Stone plant typically was shut down about six weeks a year on a planned basis, two-week outage either in the spring or fall and a four-week outage in the other shoulder months to do plant maintenance and to do extensive boiler cleanings. The boiler maintenance was a lot higher on lignite because we were on line cleaning the boiler more often, boiler tube failures were much more prevalent, just much more difficult to operate.

Since that time, we have been able to reduce those boiler wash outages to about one or maybe two a year and those outages are about a week each, maybe nine days at the outside. So you will see a lot of the ups and downs on the planned outage hours. The higher spikes with the large number of hours, those are the major outages when we do plant equipment repairs or replacements. But the overall number of outage hours in an average in a year have dropped substantially. That's the reliability side.

Some of the benefits that we have seen as we have improved our reliability and reduced our costs. This is our generation trend since the plant became on line in 1975. Just a quick comment on 1987, we had a major equipment failure, a generator rotor cracked, we were down for nine months, so we didn't produce much electricity that year. But you can see as soon as we basically made the fuel switch, we were able to start carrying two things. On lignite, we would carry a 400-megawatt cruise rating, that would be the highest load we would carry on a continual basis. And we would -- our capacity factor for a typical year was about 65 percent. And it resulted in about 25 or 2.5 million megawatt hours of electricity production.

Once we made that fuel switch, we were able to increase that cruise rating up to anywhere from 430 megawatts, we are up to 460 now and we are doing that at about an 85 percent capacity factor. Part of that is our cost control by reducing our heat rate and changing the fuels at a lower price. But no matter what we have done, as soon as we release load to be able to be sold, it's been taken by the market and that trend is really evident here. And we expect -- we have had a little trouble out here on the tail end the last few years, had some equipment limitations. Those are being replaced, repaired this year. We expect to be three and a half million to 3.6 million megawatt hours annually from this point on.

The last thing I want to touch on would be the new source review. I know Alan had to try to wade through a couple of questions there. There is a lot of regulatory uncertainty with approaching plant efficiency improvement projects. Otter

Tail's position has been if a project will allow the plant to burn more coal on an hourly basis, we aren't going to be able to touch that. If the project might allow us to burn more coal on an annual basis, that gets to be a little different and fuzzier because just the market demands are going to drive up our need. We still have margin. We are running at 85 percent capacity factor, we could push that up towards 100. There is still a lot of regulatory uncertainty.

Similar capital projects like we have done like our turbine replacements have been reviewed by other states and other jurisdictions and some of those companies have met with some stiff challenges, lawsuits and other things. We always approach efficiency improvement projects with that in mind. And just the last comment, we do work very closely with the DENR of South Dakota when we are working on these types of projects. They really give us a lot of guidance and we make sure we have their buy-in before we proceed.

Just for closing comments, I guess I'll start with the bottom one first. I believe that Otter Tail and Big Stone has demonstrated voluntary cost effective examples to our operation and made extensive capital investments to improve our fossil fuel generating efficiency, and we do believe that the commission should not adopt the fossil fuel generation efficiency standard.

VICE-CHAIR HANSON: Thank you very much, Mr. Endrizzi.

Are there questions by the commissioners? Commissioner Kolbeck. Staff members, do you have any questions? Mr. Rislov.

MR. RISLOV: You do efficiency studies routinely for your fossil fuel plants? I would guess you are speaking specifically about Big Stone.

MR. ENDRIZZI: Yes, my knowledge base is specifically Big Stone. I do have a lot of coordination with the Coyote station in Bismarck or near Bismarck, as we are very similar units, but at Big Stone we are continually monitoring efficiency. Our engineering staff, that's one of their primary functions, is to monitor, make recommendations for improvements, monitoring specific pieces of equipment to see how they are operating and then they will recommend either a repair or replace as needed. And also they are always watching industry trends, looking for other opportunities to improve efficiency. That's an ongoing effort.

MR. RISLOV: That would have been my question, without saying study, that implies something grand and expensive, but the idea of monitoring whatever is happening within the industry for efficiency upgrades, you are telling me that's a constant process within Big Stone power plant group of employees?

MR. ENDRIZZI: Typically the engineering staff, but also training the operating staff to make sure they are watching, show them what's important on just an hour-by-hour basis as well. If they make a change to one parameter, how that might affect another. So really looking at the big picture, because you can make a change to make one piece of equipment look great, but three others might not take that so well. So it's education, but ongoing specifically by the engineering staff.

MR. RISLOV: Following that along and understanding that people are aware of potential improvements, still given the capital cost of these improvements, it would seem to me that to work it up through the system is more than just an ongoing, let's say, monthly monitoring of efficiency, products available on the market. How does that process work?

MR. ENDRIZZI: Well, let's see if I understand the question. Constantly monitoring what's going on --

MR. RISLOV: Maybe I could simplify. There are capital requirements for a large utility and when we talk about upgrading a plant with significant efficiency upgrades such as Big Stone, these capital requirements have to be put in the plan I would guess a few years out. What is the process? You see something and say, I think we maybe could go this route, how long does it take to get that plan in place within the corporate structure?

MR. ENDRIZZI: On a typical project, say I'll take the low pressure turbine example, which was a five million dollar project, we usually had approval two years ahead of that time so that the equipment could be built and then plan to be installed. We usually had done, on something that extensive, it's maybe a year or two of studying what our options are. It really depends on the specific situation. We will turn around and do a quick capital project even in the same year we discover it just based on how fast it can pay back as well.

But typically we do annual budgets, I will submit my budget to Alan as one of our approvers here this summer for the next two years, but also with a 10-year plan attached, so we are looking out quite a ways. We also have to tie that in when we plan to have our outages. If it's a major project, we typically don't have a major outage every year, so we try to budget around that as well. When we are looking out, we plan a major outage in 2010, what big projects can we get done then?

MR. RISLOV: It seems to me there's, strangely enough, there's been a general reluctance to have the commission adopt this particular program. That was a joke, too. Sorry about that. But it seems to me that utilities operating a piece of equipment this expensive, such as Big Stone, so integral to the operation of the entire utility, that there will be something on paper, I don't know if it would be on a 10-year basis, that it wouldn't be a difficult task to have the commission at least review that, not necessarily saying that they are going to make any changes, but at least there would be a document capable of being reviewed and that may be more than what we are doing right now.

MR. ENDRIZZI: The documents exist. They are very fluid. For example, 2007 we were not intending to have a major outage at Big Stone plant this fall. However, last spring during one of our maintenance inspections, we found a major problem with our generator, forcing us to make the decision we were going to rewind that, moving up a major outage about three years earlier than we thought we would have. So things end up being fluid.

The concern from my perspective of having something in place that says we need to be doing this, if we force our outage schedule to something that doesn't make sense or maybe even the potential to rush in an immature technology into a plant. I have been battling that since 2002 with some technology that we purchased that didn't pan out. It's cost us many, many, many thousands of megawatt hours and many millions of dollars. We would hate to get forced into something like that. That was our own doing on that one, but we would hate to have that potential out there.

We also -- we are balancing -- we are in the business to stay in the business and we need to balance customers' and shareholders' and employees' needs as well, so any time there's more regulatory oversight, I guess that's where my concern would be with this one.

MR. RISLOV: Thank you.

VICE-CHAIR HANSON: Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation. It seems awfully benign, doesn't it? 10-year plan, you were just commenting and discussing with Mr. Rislov regarding it seems like everyone is already doing this. So again, let me ask and simplify it for me, since everyone is doing it, why not have it as a review process and give regulators the opportunity to review it?

MR. ENDRIZZI: The uncertainty I have is what is the end result? What would be the end result from your perspective? What would you do with that information?

VICE-CHAIR HANSON: Okay. As long as I have you here and we have about 10 seconds left, to what extent -- you mentioned a little bit on blending that you do and I know that you burn tires along with other. Just to what extent do you do coal blending and blending of other fuels?

MR. ENDRIZZI: We have very limited capability. We don't burn -- we don't blend coals per se. We burn in some alternative fuels on a relatively small basis. We could blend in up to about five percent on a weight basis, but we typically -- and limited supply as well. We are burning shredded tires and we are burning unusable seed corn. The supply of those is not as great as it was 10 years ago. We are probably burning one to two percent, maybe three percent on a weekly basis, but over a given year, it's probably one and a half to two percent.

VICE-CHAIR HANSON: Thank you. If there aren't any further questions.

MS. WIEST: I have one quick one. Has Minnesota adopted this standard or are they in the process of looking at it, do you know?

MR. ENDRIZZI: I do not know.

MS. WIEST: Thanks.

VICE-CHAIR HANSON: Mr. Endrizzi and Mr. Welte, thank you very much for your participation this afternoon. In approximately 10 minutes at 3 o'clock, we will resume with time-based metering. Mr. Chairman.

CHAIRMAN JOHNSON: That's right.

VICE-CHAIR HANSON: We will take a break until then.

(Whereupon, the hearing was in recess at 2:51 p.m., and subsequently reconvened at 3:02 p.m., and the following proceedings were had and entered of record:)

CHAIRMAN JOHNSON: Welcome back. It is 3 o'clock and we are beginning our fourth and final session of this South Dakota Public Utilities Commission PURPA workshop. This session is on time-based metering. Commissioner Steve Kolbeck will be serving as moderator. Commissioner Kolbeck, take it away.

COMMISSIONER KOLBECK: Thank you, Mr. Chairman. As

Commissioner Hanson stated, we are working on smart metering, PURPA standard 14 or time-based metering. We will have presentations today from Tamie Aberle, she's the pricing and tariff manager from Montana-Dakota Utilities, Erich Gunther, chairman and chief technology officer for EnerNex Corporation, and he will also have double duty today, and Chuck Rea, manager of regulatory strategic analysis for MidAmerican Energy Company.

Pursuant with Section 1252 of the EPA act, Section 111, the commission must consider adoption of a smart metering standard, and then the standard is quite lengthy. We will just go ahead and go into the presentation, and Tamie, if you want to start for us, that would be great. Thank you.

MS. ABERLE: Thank you, Commissioner. I have just paraphrased, if you will, the opening of that section of the standard 14 referred to as time-based metering or smart metering, and really I guess what I take away from that, it calls for utilities to offer time-based rates that enable customers to manage energy use and cost through advanced metering and communications technology, and I think a key term to keep in mind is "and cost" as we go through this.

Adoption of the standard would require utilities to offer time-of-use pricing, critical peak pricing, real-time pricing and demand response rates, and such pricing structures may require the use of what's been termed advanced metering infrastructure, which really involves more than a meter that can measure interval data. It's really the infrastructure required to capture the data, transmit that data to the utility company and including a data management system to do something with that data. Smart metering, then, tagged onto that is really the two-way communication piece in that infrastructure, so that would require some way for the utility to communicate back to the customer.

A couple of the issues associated that we see with the standard is if it was a standard and a mandatory standard for the utilities to offer such rates, would those rate offerings be on an optional or a mandatory basis? Even while optional would certainly be preferable over a mandatory offering, we see issues with the optional offering if it was required on a standard basis across the entire state for all utilities operating in that state. The economic rationale for those rates could be destroyed if the, for example, the cost causers stay on the standard rate and all other customers move to the optional rate.

Under a mandatory structure, if the pricing tariffs or the tariff that was mandatory for customers to take service under, under that structure, there could be substantial price risk for customers. Capital costs for implementing and installing the AMI system could be a cost burden to customers and the utility, and really it would require Montana-Dakota, all utilities, and the commission to devote significant resources to developing the cost-of-service studies and the pricing structures required to implement those rates. It would likely result in changes in billing systems on the utility side.

The standard itself, while calling for promoting conservation and efficient use of energy is appropriate, some of the other issues with that as a standard, again, are the costs, the benefits, and the equities among customers that may be required to take service under those schedules. Costs and benefits would vary by customer class and by utility. Different rates likely appropriate for different utilities and different customer sectors within a utility need to be addressed. And we really believe that the pricing options should be voluntary and designed on a utility-by-utility basis and not part of a mandatory standard.

Some of the changes in meter technology today that we have seen in recent years or past years have allowed utilities to measure various aspects of service provided to customers, and where appropriate, price differentiate for those different aspects of that service under commission-approved tariffs, again, where appropriate, so some of the meters are already providing the ability to offer some of the rates required in the standard.

Montana-Dakota does offer rates that we believe meet parts of that standard. We offer time-of-use rates on an optional basis. We do what we have referred to as dual fuel rates, so it's a rate reflecting peaking prices and controlling equipment during that peaking period. We have a radio-controlled load management program in one of our jurisdictions, which is again managing customers' use during peaking periods. And we also offer interruptible service rates or demand response rates to larger customers, and at least one of our jurisdictions where customers may respond receive a credit for being capable of going to a self-generation during a time of a peaking time on our system. So there really are ways to design programs without moving toward the full regime of a smart metering system.

Montana-Dakota has recently embarked on installing the first, what I see as the first step in that process. It's the meter reading step, but we are installing an automatic meter reading network, where appropriate, and in other cases it's just the meters that allow us to pick up those reads on a mobile basis, and it is just the first step in that process, but we believe that will allow us to explore other ways that we can take advantage of that system by utilizing the network, the interval data that's available on that network, again, looking at changes on our billing system, on our data management system within the utility and then ultimately providing information back to the customers.

And in summary, we also believe that the optional rates we have in place do meet at least portions of that standard and we really believe they should be implemented where cost effective on a utility-by-utility basis and not driven by the adoption of the EPACT standard. A more cautious approach may be to look at it in the rate case of each of the utilities as we get into that process, because most of the pricing changes that are -- or the rate structure that are called for in the standard would really require a reallocation of costs among the classes, which is typically conducted through a rate case proceeding. That ends my remarks. I'm available for questions.

COMMISSIONER KOLBECK: All right, thank you, Tamie. I'll look to Commissioner Hanson or Commissioner Johnson for any questions for Tamie.

CHAIRMAN JOHNSON: Just I want to make sure, if I can, Commissioner Kolbeck. I just want to make sure that I understand the theoretical extremes here of your concerns about optional. That the cost causers will stay on the existing rates and that others will move to the smart metered rates. In the long haul, won't rates adjust? Won't they rise for the cost causers in the long haul?

MS. ABERLE: Commissioner, yes, they will, and that's the other part of that risk, then, is increased costs, you know, really for all customers. And really the point of that slide was that if it were a mandatory offering for all utilities, and we do offer optional time-of-day rates today and those rates are designed keeping in mind that customers will shift between those rates or have the opportunity to shift between those rates, so that optional basis is certainly our preference, but we are really looking for doing this on a case-by-case basis with each utility.

CHAIRMAN JOHNSON: Well, there was an inaccuracy in my question as well. I suppose rates might go up for the cost causer but overall rates might go down because of more efficient use of energy and less energy used during peak times and different factors like that. I suppose without looking at each utility and each situation a little more closely, it would be difficult to say what the ultimate impact would be on any ultimate customer class.

MS. ABERLE: That's correct.

VICE-CHAIR HANSON: Ms. Aberle, I was real interested in the first slides of your presentation on cost. It would seem to me, correct me where I'm struggling here, where I'm wrong, it would seem that with locational marginal pricing, that if you have people who are knowledgeable about price and when they can cut back, that they would cut back and that the peak would be shaved and the higher-priced electricity would not need to be generated, wouldn't need to be delivered so it wouldn't be generated, and ultimately it would save everyone higher costs. Am I wrong?

MS. ABERLE: Commissioner, no, you are not. In that theory and if customers were participating and if we have taken into account the cost to enable that type of a pricing structure, then it may be appropriate, but I think part of the costs that we need to look at are the costs associated with enabling, first of all, that pricing structure, that we do have a customer base that is able to participate in a pricing structure such as that, a real-time pricing structure, which we do not as a utility at this point have experience with. But I know that there are others that we can look to, but again, then we need to look at and compare that to our customer base and customers able to take advantage of that.

VICE-CHAIR HANSON: I don't mean to ask you a question that you can just say yes, I agree to. I'm interested in comment and thought. I may wait and ask a question of all three of you after the presentation has been done. It seems that we have an option, do we go to smart metering or do we go to a significant education of our population? Certainly no one is going to sit around and stare at a meter and see, okay, it's high now, let's shut down our electricity. That all has to be done through different processes, which then begs the question, do we not just simply educate our population to keeping their energy use down? However, that does not give them the incentive necessarily on the higher use periods. So it seems to jump back to smart metering to encourage people to cut back on higher use during the higher cost times. Is that yes, no, in between, punt?

MS. ABERLE: I think that -- I think it's twofold. It certainly would require significant customer education and I think as we work toward that end and advising customers how they can better utilize energy to lower their overall energy bill, to go to say that we would have to take the step of smart metering for them to take advantage of that, I guess I'm not convinced that that would be the way on a wholesale basis.

The customer may see costs that we can't identify. There's a cost to not having that -- to them to not having that air conditioner available when they want to have that air conditioning available. So again, I go back to really understanding the demographics of your customers before investing in infrastructure that may be necessary to go to the strict smart metering that we have been talking about, providing them that daily, that hourly, are the customers at home at that time to look at the monitor? We are in a summer peaking situation, so I think all of those things need to be addressed before saying that on a wholesale basis, it makes sense to move to smart metering.

VICE-CHAIR HANSON: Thank you. Commissioner Kolbeck.

COMMISSIONER KOLBECK: I just had one question for you, Tamie. How much interest is there in metering? You had

had some different things that you were doing right now, different options that customers have. Is that something that's highly practiced? Is that something that people just don't know about? Is there a demand out there for net metering do you feel?

MS. ABERLE: We do not, with regard to the optional rates that we offer, we do not have many participants taking advantage of those rates. And I can't answer if it's education, if it's customer preference, time-of-use schedule, having to move their energy usage to an off-peak period, and I think that, again, we are probably focusing more on that customer education right now and I think as we move into the future, it may become something that customers are looking toward. We do not have customers asking for, if you will, on the residential side for real-time pricing or wanting to see that price signal on that frequent of a basis.

The larger customer group, we do see where right now we are really looking at the demand response rates and we have started that process looking harder at that in North Dakota at this point, just starting there, and then we will move that toward our other jurisdictions. But customers that have the ability, they may already have generation on site anyway, that they can withstand an interruption during our peak period and receive a credit for that. So we are seeing a little bit more interest in that type of a demand response rate.

COMMISSIONER KOLBECK: Your AMR, that was my second question. How far along is that, your automated meter reading? Are you deploying that on a large scale, a small scale, maybe some certain key areas? Can you explain that a bit more?

MS. ABERLE: Sure. We are actually deploying on a system-wide basis, but we have just started, so we started in the Bismarck, Mandan, Mandan, North Dakota area, and we will be working throughout the whole entire service area and implementing that infrastructure. Certainly where we have gas and electric service, we will be utilizing the network, which will provide us the opportunity to have interval data available to us. In some of our gas only areas, those may be a mobile read at this point in time, so we wouldn't necessarily have the interval data, but we also have the capability to expand on that and if the economics change in the future, we could be installing the network system in all of those areas. And it's there to reduce meter reading costs. On the other side of that, it also provides us the opportunity to look at some more distinct pricing schedules because we will have that data available.

COMMISSIONER KOLBECK: Commissioner Johnson, do you have a question?

CHAIRMAN JOHNSON: How often and to what extent do you -- thanks very much -- how often and to what extent do you analyze these different types of time-based metering for any given customer classes to determine, you know, rolling out a new program might be in the interests of MDU and its customers?

MS. ABERLE: Well, it's an ongoing process, but it really is driven by for us, as an investor-owned utility, it's going to be driven by a rate case process, knowing that to implement a rate structure, that would cause, potentially cause cost shifts among customers or may require us to put out -- implement a new customer class. It's really looking at all of the rates and so it becomes a bigger -- in order to implement that, a bigger project and more involved.

But we do look at those different types of rates and it's becoming a bigger part of our integrated resource planning process, looking at our customer survey data and trying to I guess gauge what customer interest is, and as we look at what our future costs are, where some of these technologies will make economic sense for the customer and for the utility. We have talked about that, as we analyze gas conservation programs, we would do the same through our electric integrated resource planning process, looking at the costs and the benefits of offerings such as rebates, but also including different rate schedules.

CHAIRMAN JOHNSON: And I'm presuming that MDU has more robust demand-side management type plans than they would have had at the time of their last rate case. So certainly those have been augmented or expanded in absence of a rate case. Is there a particular difference between the possible cost shifts?

MS. ABERLE: The repricing of all of our rate schedules would just -- I am making an assumption, but that we would be required to file the cost of service study and all of this to make those changes. The demand-side management portfolio that we have in place is really looking at changing customers -- enticing and incenting customers to move to a more efficient appliance that they may have already been going to purchase, but moving to a more higher efficient piece of equipment, so those aren't really changing the rate structures or the tariff sheets, if you will.

CHAIRMAN JOHNSON: I think I may have got some of the program offerings from MDU messed up with some of the other utility companies in the state, but I know others have situations where they will send out a signal and different large loads will adjust their energy usage at that time, which presumably does have an effect on the fuel clause, if nothing else, on the price of the fuel. Thanks very much.

COMMISSIONER KOLBECK: Commissioners. Anything from staff?

MS. WIEST: Going to the programs that you offer today, I know you said you didn't have a lot of customers on; is that correct?

MS. ABERLE: That's correct.

MS. WIEST: But could you state whether any of those are more effective than the other programs or which is your most effective program, do you know?

MS. ABERLE: Well, again, it would depend on customer class. The demand response rate, I think that -- we do not offer that in South Dakota at this time, but that we have offered in North Dakota, I think it's really looking at the larger customers. We have more of an industrial base, if you will, in North Dakota than we do here in South Dakota. Those customers, the economics make more sense for those customers to take advantage of that rate structure.

MS. WIEST: Of those programs, which do you offer in South Dakota, the ones you listed?

MS. ABERLE: The time-of-use rates and the dual fuel rates at this time.

MS. WIEST: Could you explain the dual fuel rates in more detail?

MS. ABERLE: Dual fuel is a rate that is applicable or available to electric space heating customers and during certain times of the winter peak, that load is controlled.

MS. WIEST: In any of the other states you operate in, do any of those states require any types of smart metering or is it all done on a tariff basis or any laws that require it?

MS. ABERLE: No, there are not.

MS. WIEST: Thank you.

MR. RISLOV: Hi. Would you agree that this particular standard will have a much more dramatic direct effect on the customers than any other standard we have discussed today?

MS. ABERLE: Yes.

MR. RISLOV: As such, I think there's going to be a lot more publicity and perhaps a lot more demand coming from the customer over the forthcoming years than what we would see on any other standard we have looked at today.

MS. ABERLE: Yes.

MR. RISLOV: And that concerns me, for a variety of reasons. It seems to me that we have had some success with passive systems that have helped customers eliminate usage during peak periods and thus helped the utility from having to buy that high-priced peak power. What does MDU do as far as just passive, I'm calling them passive to the customer, what do you have in place for your customers to help them shave usage during the peak?

MS. ABERLE: We have offerings on the demand-side management portfolio for incentives for installing more efficient air conditioning and lighting retrofit programs for commercial customers at this time, I guess if that's what you are referring to as passive in that the customer can take the steps necessary to reduce their usage during what are predominantly peaking periods.

MR. RISLOV: It strikes me at least now with the technology available for most customers in South Dakota, a passive method, and again I call it that, it really isn't passive, it's passive in the sense that the customer doesn't have to sit monitoring a meter within the customer's house, knowing what that customer is going to pay for energy if they consume it at that particular point in time.

MS. ABERLE: And the other program that is part of our integrated resource plan that we are analyzing, it was mentioned in the 2005 integrated resource plan and we are continuing to evaluate is an air conditioning control program where it would be based on a thermostat is what we were initially looking at, so that we could send a signal to that thermostat and control the customer's usage during our peaking period. So that is probably the one program that we are focused on right now that would really speak to what you are talking about.

MR. RISLOV: Maybe a bit off the subject because we are talking about rates. I believe that the customer has some control over as far as choice is concerned and it can affect cost, although I don't really in my mind think there's a whole lot of difference, I think we are talking about saving the utility costs in the long run and passing those costs back through to the end use customer. Why haven't you implemented a program such as the one you just mentioned?

MS. ABERLE: We are really looking at the costs associated with that and based on customer response in the past have not seen the need to do that prior to this time.

MR. RISLOV: I agree that for time-of-use rates and some of the other rates, there is some cost shifting going on, some unearned cost shifts where you may be paying more than you should, you may be paying less than you should. I agree with that. Is there any other rate design as far as customer-controlled rate design other than real-time pricing that won't allow that to happen?

MS. ABERLE: Not that -- I'm not sure.

MR. RISLOV: I'm just wondering. Are any of these rates effective in the long run for customers other than real-time metering where the customer is in complete control or at least is given control over the system?

MS. ABERLE: Well, I think that customers, even in a time of use, it's a larger block, but customers on the commercial side, if they are able to move a processing or rotate shifts to take advantage of off-peak pricing, can take advantage of that and will result in lower costs to them.

MR. RISLOV: Thank you.

COMMISSIONER KOLBECK: All right, thank you, Ms. Aberle. We will move on to the next one, Erich Gunther, you are on the hot seat. I should mention before we get too far along, for those listening on the Internet, I know when I was in school, I wanted to know when we were getting out. It's about 4:30 is when we plan to wrap up and the commissioners, my fellow commissioners and I, Commissioner Johnson will wrap it up for us. That will happen in approximately an hour. Mr. Wilcox, you are back, you can stand up here in just a little bit. But Mr. Gunther, have at it.

MR. GUNTHER: Thank you, Commissioner, thank you for the opportunity to talk to you today. I will give you a very brief background from where I'm coming from. I'm speaking to you with several hats on, Chairman and CTO of EnerNex Corporation. We are an electric power engineering, research and consulting firm. But I'm also representing here today the Department of Energy's GridWise Architecture Council and I'll give you a URL where you can find out more about that organization at the end of the presentation. I'm also the chairman of the UtilityAMI organization representing about 60 utilities developing common requirements for advanced metering infrastructure.

Basically what I want to do is take a little bit of different view, talk about some of the definitions of what we mean when we talk about smart meter, smart grid and the like. This is what I want to talk about, how is it defined today, some of the benefits, how you will find the benefits, the requirements process necessary to find those benefits, the technologies necessary to implement it, where the home and business fits in and some of the lessons learned from projects that we are working on. I am also the primary consultant for

Southern California Edison's AMI project, advanced metering project and Consumer Energy's project, they are in Jackson, Michigan.

Let's start off with a couple of definitions. A lot of people have different definitions of smart grid, but the main thing I want to point out is the smart metering aspect is just one of many applications in overall smart grid infrastructure. The definition that I show here is one that you will likely see raised in the Senate Energy Committee tomorrow, who is going to be looking at addressing what comes next after EPACT. But basically this definition, an enhanced electric transmission distribution network extensively utilizing Internet-like technologies, communication technologies. So we have come up with this definition for what smart grid really means.

But there's other definitions as well of different aspects of this we need to pay attention to. They are all based on this concept of there's an overlapping set of capabilities that as you build more and more, you create what we like to think of as the smart grid. So if we look at what has been going on in the automatic meter reading space, that's one of many potential applications that fall within the concept of advanced metering infrastructure.

Advanced metering infrastructure generally includes things like remote turn-on, turn-off. To take full advantage of it, often it requires new rate designs, including other applications like outage detection and the like, and as we add even more applications and more integration of other devices, we get into those capabilities plus other system-wide capabilities, the ability to operate the utility system more efficiently, improve utility operations, dynamically correct disturbances on the grid and the like. So I like to put this concept of smart metering in the context of the bigger picture.

Another definition for advanced metering infrastructure, this one has been developed by the UtilityAMI organization, again a group of about 60 utilities right now that are participating in this. A three-part definition. Part one again talking about the integrated collection of devices, but especially really referring to the fact that this interconnection of devices is throughout the utility as well as all the way back to the customers themselves. That's an important aspect of the definition.

A second part of the standard really defines what we mean by advanced or smart. In our case we are referring to the automation of the system but also doing so using open published standards that facilitate interoperability, making it easier to deploy these systems and maintain them over time.

The third part is one of the important ones in that the infrastructure that you put in to support automatic meter reading, advanced meters and these other applications, it's the infrastructure that you end up putting in place enables a wide variety of utility applications, some of which provide societal benefit, implement policy, but it turns out that there are some significant benefits to be found operationally within the utilities themselves, and I'll talk a little bit more about that.

So part three is really the key from the GridWise Architecture Council's point of view and other organizations I represent, such as the EPRI IntelliGrid, a modern grid initiative related project, the EPRI IntelliGrid effort. All those organizations agree that AMI is an enabler for a wide variety of utility applications, so we like to say that the focus should be on the I, the infrastructure aspect of AMI.

One of the things to recognize is that it's really important to identify the benefits. Every utility is different, the geography, the system design, the regulatory environment, the business practices, existing optimizations that a utility has already put in place all make the determination of the business value for automated meter reading, putting in AMI infrastructure, rates, every aspect of the smart grid. Each utility will have a different set of elements that make or break the business case.

There are numerous examples from other utilities of how you identify these different opportunities. In California, for example, a very thorough framework was put in place with which all of the utilities were expected to follow that framework so there was a common method for determining where the values were and the costs were. So there's a number of examples for how to do that in a consistent way. One of the key things that we recommend is that you follow a very well-defined process to identify those benefits, so if you decide to go ahead with any aspect of smart metering or grid monitorization, advanced metering infrastructure, one of the most important things is to focus on a detailed process or a thorough process in capturing the requirements so that you know exactly what value you want, both business value, societal value and enforcing policy and do that in a way that is demonstrable to all the stakeholders.

With work that we have done with EPRI IntelliGrid project, we have put together a very detailed application guide on how to go through that process and that's the process that's being applied at Southern California Edison, Consumers Energy, Alliant Energy and other utilities and it's shown to be rather effective. In addition to this, I've also included, and I think it's posted on the Web site, a set of recommendations for regulators, policymakers, decision makers on how to evaluate the technologies and opportunities advanced metering can provide.

Leveraging the infrastructure is really key. This is just one example from Southern California Edison. Basically we want to enable the customer side, allow the customers to have a lot more choice than they have had before, to use this infrastructure to manage distributed resources, but also to obtain operational efficiencies within their own organization, and it turns out there is quite a bit of value right in there. But do this with the future in mind, basically creating an infrastructure and a network to support the unforeseen applications. It turns out that you are able to make the business case for implementing AMI in one or more of these areas, but the infrastructure can be utilized and leveraged for many other elements down the road.

There's a number of technologies that are available to help do this on the metering side. We have got sort of like from the old to the new over here. From a meter reading point of view, manual through AMI, so really we are dealing with, in order to support advanced metering infrastructure, we need the latest in metering technology, interval metering, we need the communications network, we need time-based measurement, hybrid or solid state for advanced. A number of complications become possible. We have a number of pricing options, customer options. We can use this to enhance utility operations in the advanced metering infrastructure approach. And there is more interfaces or points of interoperability that allow us to find areas where we can share information with other entities, with the appropriate controls, of course. And with the AMI situation, it allows us to apply devices to take advantage of the infrastructure.

It's important to note that customers do not want to be energy managers nor probably should they. It's really important when deploying an advanced metering infrastructure, smart meters are one thing, but if you are going to use it to support demand response programs, you are going to use it to allow you to capture the revenue associated with innovative rate structures, you want to provide technology that acts as a proxy for the user, to use that information and extract the maximum value to it. EPRI likes to call this concept the prices to devices approach and that's a simple way of putting it.

Communication technologies are evolving quickly. The most basic of meter reading technologies, the walk-by technology has been around for a while. Drive-by has moved on to fixed, but pretty much most people recognize the state of the art today are two-way fixed radio networks that allow us to provide a lot of flexibility in the applications we deploy, not only for the meter reading aspects but again to serve as the foundation for future utility applications. So there's plenty of technology out there. Technology is not the problem, we have metering technology, we have communications technology. It's really all about capturing requirements necessary to figure out what to deploy. Costs are going down because of some of these early applications, costs are going down rapidly, so you need to evaluate. If you did a business case a year or two ago, you need to do it again. The assumptions you made a couple years ago have changed drastically and so that's an important thing to realize.

Integrating the home, very important to support this, again, prices to devices concept. You really need to enable the residential user or the commercial user to take advantage of the rate structures that are in place through the use of the technology, and there's all sorts of work going on in all these areas to define the standards, the information agreements, the modeling protocols necessary to make this happen and provide interoperability with multiple vendors of equipment.

Some lessons learned. One of the things that we run into in all the utilities we work with -- every utility we have worked with so far, by the way, has gone through an interesting process. First you have the Energy Policy Act, which is driving proceedings such as this, which are then putting some pressure on utilities to take a look at what they should do, and so that gets them to look at it. The first reaction is going along kicking and screaming and looking at it because they were told to, but every utility we have worked with so far has eventually, surprisingly, found value, especially in areas that they didn't expect.

And the really cool part about this is that as a utility, putting the utility point of view hat on, you are being asked to go and investigate something, so you are looking at something you might not otherwise would, but if you can find the value in it, you will have the backing of the regulatory community both locally and at federal government levels to do something that turns out has high value operationally usually for utilities. Not every utility has this case, but every one we have worked with so far, they have eventually turned around and said, there's some pretty good value here, we think we will do this. But it's really important to adopt a process that let's you find where that value lies.

So one of the problems is the fear of picking the wrong technology and the only way you can avoid that is by going through a detailed requirements process. I'll have to go back a few slides here in a little while because with this remote here, I skipped over the slide that shows the process we actually follow, the graphic, but I'll get there eventually.

One of the issues that people run into is the concept of trusting a single vendor. Some utilities would like to trust a single vendor so they have the single throat to choke to make it right, but more often in the work that we are doing, we really want to try and get multiple vendors involved. Through the use of standards, we can mix and match the different equipment so that we don't have a vendor lock-in situation and don't get our throat choke if that vendor goes away.

Some of the other lessons learned on implementing this is that there are huge process changes required with any utility organization in order to implement advanced metering infrastructure. It touches almost every part of the utility organization, so that's really important to recognize. Again, our point of view is that it's not just a meter reading system. You really should think of this as an overall data collection command and control system, widely dispersed through the utility and essentially as forming the basis for this concept of the smart grid.

Other lessons learned are that you can't implement advanced metering infrastructure with the typical constraints of silos that exist in many utilities. This is more of an issue for very large electric utilities, but the silo problem can be found in all different utilities. You have to find a way to overcome those internal issues of communication in order to implement AMI or it's just not going to happen.

For this audience, an important aspect is to see to it that the regulatory environment is such that utilities can take full advantage of the system, so that the regulatory stability needs to be there, the incentives need to be there in order for utilities to maximize the value from this system.

So just summarizing, we believe in focusing on the AMI, lay that smart grid foundation, create a good business case model and update it often, the costs change very quickly. One of the things that we have found with every utility we have worked with, that value is found in places you don't expect. For example, one utility may have expected to get all of our value out of improving our outage management system but instead it turns out that we were able to, through demand response and load control, greatly reduce our expenditures on importing energy. Every time we go through one of those, the value is in places we don't expect.

The costs are changing dramatically. Not being first to do this is a good thing and luckily you have got several other utilities in states who are doing it first and breaking down some of the barriers. Every one of these that we are doing right now, the cost to the utility to implement has gone down significantly. The time to get their regulatory community up to speed on what's possible has gone down, so that's a good thing. It is possible to implement these systems incrementally so you don't have a huge impact within the utility organization as well as to the ratepayers all at once. As a matter of fact, if you do it properly, there should be no net impact to the ratepayers. That's important to take advantage and leverage fallen costs of equipment.

And one main thing I wanted to get across is there's a huge body of knowledge to draw from in this space. Information sharing has become the norm in this arena. Southern California

Edison has pioneered by basically publishing everything they have been doing on their Web site as well as through OpenAMI, OpenAMI or UtilityAMI, and UtilityAMI and other organizations are primarily being used to help the information sharing. But these utilities are sharing business cases, they are sharing RFQs, sharing the use cases or the scenarios, technology evaluation methodologies. Lots of information is available and we really encourage everyone to take advantage of that.

Just to summarize a few resources that you can look at, the Department of Energy GridWise Architecture Council is something you could take a look at, and again it's posted on your Web site here, it should be, the interoperability checklist for regulators and decision makers. We have several other publications, including our constitutional principles with which the other organizations I mentioned here are working with, EPRI, UtilityAMI, Modern Grid Initiative, several different organizations that are working in this space. With that, I will answer any questions.

COMMISSIONER KOLBECK: Thank you, Erich. That was fantastic. We will start off with questions from Commissioner Johnson or Commissioner Hanson.

CHAIRMAN JOHNSON: I'm interested in how most utilities handle cost recovery. In fact at some point toward the end of your presentation, you mentioned there shouldn't be any net cost pushed down to the ratepayer. Tell me how that works.

MR. GUNTHER: Every state is different, every utility is different and it just depends on the time frame. Initially my statements really related to the net cost overall should go down, benefits should increase, overall costs should go down. The utility, just the normal way that the utilities recover infrastructure cost is going to go into the rate base, so there may be a rate increase to recover some of that cost, but the concept is that over the long term, each individual consumer will pay less for energy if they are technology enabled to take advantage of the innovative rates in place. That's a complex economic mix that we evaluate for each utility and that's where my comment about regulatory stability is important. It's important for the utilities to know exactly what they are going to have available from a tariff point of view, how long those are going to be in place so the business case can be made.

CHAIRMAN JOHNSON: Do we have good information from other states on exactly what the effect on consumers has been? It seems if the commission were going to adopt a standard that would impose millions of dollars of costs onto utility companies, that we would want to know that at some point the benefits would indeed come, would arrive at the ratepayers' doorstep.

MR. GUNTHER: There's very good data. This is something that's been studied to death over my career and one of the problems is the problem with pilotitis. Everyone puts in a pilot and doesn't go farther with it because they forget or don't realize how these things need to scale. The advent of cheap telecommunications and other technologies make what's old new again. But what's been studied very thoroughly is how customers respond, so we have got very good data from many states who already have systems in place, how they respond. Even California, who has the lowest per capita energy use in the country by a lot, still respond to demand response signals, for example, or still respond when given the opportunity to have a time-of-use or real-time rate.

CHAIRMAN JOHNSON: Are there -- have studies indicated any particular regional differences? There are large variations in the cost of energy, there are, I suspect, large variations in customer sophistication and interest in really becoming an active participant in this sort of program. Can you speak a little to that?

MR. GUNTHER: Very much are regional differences. As I mentioned in the early slide, every state is different. Geography plays a big role, weather, all manner of variables come into play. You could argue that different parts of the country are more likely to want to respond. People say, those Californians, they will do anything, but there may be a little bit of truth to that. But the more important thing we find is if you enable the customer with the technology to do this and they don't have to think about it, getting the customers to participate is not so much of a problem. But you have to analyze the regional aspects.

CHAIRMAN JOHNSON: This is an awful question to ask and it's really not going to tell anybody anything, but I'll ask it anyway. Give me an idea of some average savings that a customer might, in the past might have experienced, or give me a range, a ballpark. I don't have any way of -- I guess I know what the cost is of a particular residence, you have indicated it's 300 bucks, but I don't know what to compare that to.

MR. GUNTHER: The savings on an individual basis, it depends on how much of your total budget your energy bill is for you to determine as an individual as to how much a little bit of energy savings is. So the amount of money an individual can save some would argue is a relatively small amount, but it really depends on how you use energy in your overall economic status as to whether that's a lot or a little. On aggregate, it can present significant overall energy savings to the system as a whole, so that's a good thing, and to society as a whole. So that's the best way I can dance around that issue without giving you a bunch of spread sheets.

CHAIRMAN JOHNSON: I do like spread sheets, but perhaps for another day. Given that large customers use so much of the energy resource of most utilities and given that I think most of the utilities doing business in South Dakota have focused their demand-side efforts on large customers, that's really the low hanging fruit from an efficiency, from an effectiveness standpoint. Could someone argue that that's the better approach instead of trying to put a smart meter in every residence?

MR. GUNTHER: Again, this is a regional thing as to what makes sense. Almost every utility, you want to go after the industrial and commercial load, provide those innovative rates first to them. That is where you can get the largest value. In California it's 30, 30, 30 as far as the breakdown, a third residential, a third commercial, a third industrial. A third residential in California where they are trying to keep the lights on this summer and next summer is a big deal. So every little -- having every little incentive is key. Other states don't have that problem.

CHAIRMAN JOHNSON: Thanks very much. I suspect I put us behind time. My apologies. Go ahead.

COMMISSIONER KOLBECK: Commissioner Hanson.

VICE-CHAIR HANSON: As a matter of fact, you did because I didn't have a question, but as you asked your questions, I developed one in my mind. When I was utilities commissioner for the City of Sioux Falls, we switched over to an automatic reading system. It was interrogated from the office, called in over phone lines. In doing that, looked at it from a standpoint of cost benefit, not having people out in the street, et cetera. What do studies show is the length of time for paying off this cost? Because it's a significant cost to change over, have the metering, but to have a system by which to store the data and interpret the data and et cetera.

MR. GUNTHER: If you only have that one key benefit, in other words, your focus on meter reading, you are only putting in a communication infrastructure that's good enough to bring that data back, you may not be able to make the business case. As a matter of fact, there's many that I have looked at you can't make the business case on that at all.

But the whole point about what we are trying to do from a smart grid point of view is look at a whole variety of applications that utilize communications to support a portfolio of applications that have value. And it's that portfolio of applications, that portfolio of benefits that reduces the risk to everyone for implementing smart metering, and as some utilities have found, they find new value every day as they run the system.

VICE-CHAIR HANSON: So the cost is significant. However, it's the fact that there's energy efficiency married to the additional operational opportunities.

MR. GUNTHER: Lots of operational opportunities. You have the cost of reducing the meter reading function, so that is one. But it's really all the other applications that really come into play. Outage management is one that oftentimes is a good one, especially if there's real value placed on improving reliability statistics. The demand response, if you can manage your peak through demand response as opposed to running expensive peaking units or buying energy elsewhere on the market, those values come into play very quickly.

And there's some sample -- on UtilityAMI Web site, we are gathering sample business cases from many utilities. It's not quite ready yet, but you can, if you look at the California proceedings, you can look at some of the business cases that have been posted there for California utilities, and NISEG (phonetic) and Rochester Gas and Electric have posted their plan, which has some of the numbers in it as well.

VICE-CHAIR HANSON: From an application process, then, from experience, is there -- I hate to use the word reasonable because it means something different to everyone -- is there a legitimate decrease in usage to justify the expense?

MR. GUNTHER: As far as decrease in usage, for the most part, the simple answer is yes, but the main focus on the people that I'm working with right now, the utilities who are doing this first are those who need to manage their peak, so they are trying to put the incentives and rates in place to handle the peak aspect of things, so the result is shifting energy use so they don't have to build more transmission capacity, build more generation and the like. So in that case, for the shifting there's not a huge net decrease, but there is some. There's a significant value, though, to the end user in the reduction in their energy cost across all commercial, industrial and residential.

VICE-CHAIR HANSON: Thank you.

COMMISSIONER KOLBECK: All right, thanks. Commissioner Hanson actually asked my question, so staff, do you have anything?

MR. RISLOV: Does this go down the system, always go down to the residential customer or can it be stopped at a level above that, the so-called lower hanging fruit?

MR. GUNTHER: It's all about the requirements. It can go wherever you want. One of the fundamental principles of GridWise Architecture Council and IntelliGrid is to spend the bulk of your time up front analyzing the requirements, policy requirements as well as the business requirements of the utilities. You will answer questions like that once you take the time to do that. And we have developed a comprehensive approach, a template many utilities are now starting to follow and regulatory organizations are starting to follow to figure that out.

MR. RISLOV: And again you have explained that this can be taken in steps, at least with regard to implementing whatever is available, but asking this question, what would it cost the individual customer for infrastructure within that customer's home, I'm talking about the residential customer, what would it cost? I assume this 300 relates to what we consider to be utility costs that are paid through rates.

MR. GUNTHER: Right, that's an older utility cost. The cost for Southern California Edison as we deploy this summer is going to be under $100 for a smart meter with integrated disconnect, so we have already gone down to under $100 for the main meter. Add $50 more to that for a high end programmable communicating thermostat, which is going to be the primary demand response vehicle in California. Starting in end of 2008, early 2009, all new construction in California, it is mandatory to have a programmable communicating thermostat to respond to demand response, so that's 50 bucks for the consumers.

MR. RISLOV: I believe your diagram showed controls going to individual appliances within that house and certainly there would be a wiring cost and cost of other facilities, too.

MR. GUNTHER: Right, the minimum will be the PCT, which is the lowest cost entry. For Southern California Edison and other utilities have very effective direct load control programs and so those costs are still there, they have come down a bit, so the values I showed there were for some of the direct load control, but the PCT has the potential to be a high value approach.

MR. RISLOV: And I don't know if you caught my question before, I don't know how clear that question was, but

I guess I'm more interested in the customers being able to take advantage of these programs without active intervention, which I guess the view of sitting at a computer monitoring it all day.

MR. GUNTHER: The PCT is one of the key elements, the thermostat. You purchase it at Home Depot, you put it on the wall, it receives the pricing information and it does the right thing. When it receives a high price, the default programming would, in the summer, increase the temperature by four degrees, six degrees, whatever you want it to do, and you inherently take advantage of the reduction in energy use and hence cost during that time.

MR. RISLOV: One topic that's being discussed quite a bit within MISO is the ability of customers to take advantage of demand response opportunities, and this may be getting a little far fetched, again referring to low hanging fruit, but if this were wired to individual homes, would that somehow have an impact on the utility decisions within the MISO real-time market, let's say? Has that been explored in California?

MR. GUNTHER: We have identified a sub system within any utility that's necessary to take advantage of such things. We call it the demand response analysis and control system or DRACS for short. We are going to be doing some research with the California Energy Commission to define the details of that, but basically that's a system that, knowing -- by using the information available from the smart meters as far as how much energy is available from a demand response point of view to be released at any one time, it can be presented to an operator just like any other block of energy and dispatched, so that's a short version for a relatively long proposal that discusses that concept. But yes, it's being looked at.

COMMISSIONER KOLBECK: All right, thank you. We have one last presenter, Chuck Rea. It's your responsibility to sum up everything we have heard here today and you have about 28 minutes, sir. Chuck is regulatory strategic analyst and he's with MidAmerican Energy Corporation, and after that, we will give it back to our Commissioner Johnson and we will have a little wrap-up and we will be done for the day. Go ahead, Chuck.

MR. REA: Thank you, Commissioner, and thank you all for having me here to talk about MidAmerican's point of view regarding the PURPA standards related to time-based pricing.

A lot of what I've got in here is information that Tamie and Erich have already covered, so in the interests of time, there will be some of this that I won't spend a whole lot of time on, but my goal here hopefully is to maybe give you some different ideas regarding these pricing programs that you maybe haven't considered, maybe some policy issues regarding the different pricing options that you may want to consider. There is good and bad in all of these things and so it would be good, I think, to talk about what some of that might be.

I won't say a whole lot about metering definitions. Erich and Tamie have covered all of that. The one thing I will say about that is that we are three for three now in presentations that talk about metering that have a metering definition slide in it, so the people up here must think it's important, and it is important, frankly. It's important that when we have these conversations, we have a common understanding of what the terms mean.

We have spent quite a bit of time sifting through other utility metering programs that are marketed or branded as smart metering that may or may not actually be smart metering relative to the definitions that we have talked about before. So I say that just so that it's important as you read literature and you look at programs that other people are doing, that you make sure that you understand exactly what they are doing.

MidAmerican has quite a bit of experience in load curtailment and load control. We have about 140 large customers system wide on interruptible load rates and we pay these customers anywhere from $30 to $40 a kW, depending on the length of the contract and what service territory they are in, for the right to interrupt their load on peak demand days subject to a number of terms and conditions that are in the contract. We have one customer in South Dakota that takes advantage of that kind of program.

Before I go on, I didn't have the obligatory map of MidAmerican service territory, but I will say that probably 90 percent of our electric business is in Iowa. We have a fair amount of service territory in Illinois that we serve and we have a small service territory here in South Dakota. We have a much bigger gas presence here in South Dakota than we have electric, but we do have some electric service territory here in the southeastern part of South Dakota.

We also have significant experience with residential direct load control. We have about 54,000 residential customers in Iowa on our direct load control program and we give these customers a $30 to $40 annual bill credit for the right to cycle their air conditioning program during the hot summer days, and all of that is automated. The technology is in place, we send signals out to equipment on the air conditioning unit itself and that cycles the air conditioning and the customers don't have to think or do anything about it. That's about 10 percent of our total residential base probably.

Between the large load curtailment and the direct load control, we can reduce our peak demand by I would say probably as much as 10 percent on a system-wide basis, and we have a peak demand of over 4,000 megawatts, so that's the size of a pretty good combined cycle unit that we are able to avoid through this program.

We have modest experience with time-of-use rates. We have optional rates for all of our residential and commercial customers in all of our service territories. We have three commercial customers in South Dakota that are on those rates. We don't have any residential customers in South Dakota that take advantage of that. We have some mandatory time-of-use for our larger industrial customers in our Illinois service territory and the eastern part of our Iowa territory. Time-of-use is not mandatory for anybody in central and western Iowa and in South Dakota.

We have limited experience in real-time pricing. We do have an optional offering for real-time pricing in Illinois that is legislatively mandated for industrial and commercial customers. We don't have anybody currently on that program. We did have one customer once who spent a year on real-time pricing in Illinois, so we have the infrastructure in place to offer that, but we currently don't have any customers on that rate and haven't had for quite some time.

The question is, does all of this comply with PURPA standard 14? With the exception possibly of the residential direct load control, which really isn't contemplated directly in the standard, I would say yes, that they comply with the PURPA standard and we believe that the requirements under PURPA standard 14 are met effectively with MidAmerican's current tariff offerings.

The point of saying that isn't to say that we comply with the standard so the utility board here, the commission doesn't need to consider this anymore. The point of saying that is that probably most any utility in the country can probably tell their commissioners that the program offerings that they have in place satisfy the standard, but that's a different question than is -- well, the real question, though, I think is, is that really what you want to do, is that where you want to stop? Are you interested in just making sure that the standard is being complied with by the utilities you have jurisdiction over or are you interested in doing something more? And I think that's kind of the policy question that you may really want to consider.

These are the definitions that are in the standard. I'm not going to talk much about how all of these are defined here. I do want to spend a little bit of time talking about some of the good and bad in each of these rates. I'm not going to have a slide for credits for large customers. I'm not entirely sure really why that's even in the PURPA standard. It doesn't really seem like a pricing program to me as much as it is just kind of a program to buy back capacity from customers. It's not to say it isn't effective, because it is, but I'm not going to talk a whole lot about that.

Time-of-use pricing, most utilities offer this. It's a pretty common thing in the industry. Most utilities have at least optional time-of-use rates, and frankly, most of them aren't very good, in my opinion, including MidAmerican's. You have fixed hourly windows during the summer and sometimes during the winter where during week days where prices increase -- and I put a typical rate up here just in comparison. This is very loosely based on what MidAmerican might calculate a residential time-of-use rate to be. Typically these rates are cost-based rates, but they don't have to be. They can be market based.

There typically aren't a lot of customers on these rates. Most customers that are here choose to be there because their usage pattern already fits into the windows, so it's just something they can naturally take advantage of. They are modestly effective I would say. They could probably be more effective, certainly could be more effective if there were a bigger and more focused education effort. Georgia Power is a utility that a lot of people feel is pretty much at the forefront of offering a wide variety of time-based pricing, time-of-use pricing, real-time pricing, very much into that. They have talked about -- I don't know if they have implemented it, but they have talked about a program where they will offer their customers the option of defining their own time-of-use window. So some customers may decide that noon to 7 p.m. fits their need, some customers may feel like 3 p.m. to 9 p.m. fits their needs and they had actually talked about a program where customers come to them with the time-of-use window that they think would be most appropriate and then Georgia Power sends them a quote back and says, based on this, this is what your price is going to be.

(Brief pause for reporter to plug in her machine.)

Two other things I'll say about this. The biggest thing that time-of-use rates have going for them is that they are pretty familiar. I think that people in the industry and people that do regulation understand time-of-use pretty well. It's a pretty easy concept to get. The biggest problem that I think most current programs have is that the on-peak periods are way too long. You will see a lot of time-of-use rates that utilities have that are 8 a.m. to 8 p.m. on peak or 8 a.m. to 10 p.m. on peak. I have a friend in the audience that refers to those rates sometimes as vampire rates because vampires are the only people that can take advantage of them. And the thing that happens then is if the windows are way too long, then the price differentials aren't very big, which also tends to make it not very advantageous to be on for most people. They are defined more from a utility's internal considerations than from a customer's considerations and that is one of the things that leads to windows that you would typically see.

Critical peak pricing is another program. This is kind of my personal favorite. It's an idea that's sort of gaining ground and I think more and more people in the industry are starting to think that maybe this is a good idea. The idea is that it's very similar to time-of-use pricing, but it only operates on really hot days or on days of very high system peak demand, and what you would see here is a rate -- my version of this would have a rate that you basically have a customer charge and an annual energy charge that's fixed over the entire year, except during periods of where you call the critical peak price, and what I have got here is an example where energy during peak pricing periods might be. Well, in this case it's 17 cents a kilowatt hour and it would apply for a very short period of time on a summer day that was over 90 degrees, and perhaps in some programs you might have something that would be even a super peak energy rate that would apply the same way but on days that were even hotter, 95 degrees or something even higher than that.

This kind of rate, most people think of this in terms of market based, but I think that it can either be a cost-based rate or a market-based rate. The thing that I like about it is that it correlates pretty well with how we have already conditioned customers to think about energy usage. For a utility like MidAmerican that doesn't have a lot of exposure to the wholesale market, it correlates really well with our costs, it correlates really well with hot weather, which is how we have conditioned customers in the past to react. We have had peak alert programs in the past at MidAmerican, I'm sure other utilities have had peak alert programs where if it gets really hot during the summer, then we have a radio message or something that says, please don't use your washer and your dryer from, oh, in the afternoon 3 to 7 p.m. or something like that. This fits in right with that.

One way to look at it is kind of like a peak alert program with a price increase associated with it. But it does require some pretty significant notification capability. This is probably only -- if you have a program like this, you are probably only going to send this price signal maybe a half dozen times a year or something like that. If you are only going to do it for a limited number of times, you need to make sure that customers get the signal, so there is some significant capability that you need to build there.

Real-time pricing is also a pretty well-understood concept, but generally it's been our experience that without a lot of education and without a lot of work, it's not very popular with customers. That's not true universally. Georgia Power certainly has had a lot of luck with real-time pricing with their large customers, but they have put a lot of effort into making it work, too. Prices tend to be stable most of the time. Prices do change hour by hour, but they tend to be stable for most of the time during the year.

It generally correlates with hot weather and peaking conditions, but it doesn't always correlate with that, which is kind of the big drawback sometimes. A typical rate might have a customer charge and an energy delivery charge and then the commodity rate would vary hour by hour. Typically we have seen prices in the market anywhere two cents a kilowatt hour off peak to maybe five cents a kilowatt hour on peak, and that would be as it's defined by the wholesale market.

Typically this would be market-based, although it can be cost-based. Most programs are market-based real-time pricing programs. Georgia Power's is not. It's the only one that I know of that isn't, but it doesn't have to be market-based. It requires a lot of ability to send prices to customers and have customers be able to monitor prices on a day-by-day basis with the technology that Erich talked about. It requires a particular ability to communicate with customers when prices aren't intuitive. If prices spike on an April afternoon when the weather is not hot and you don't have a peaking condition but something happened to cause a spike in the market, then you have to be able to explain to customers what happened.

There's also the issue of who assumes the price risk. Generally it's been our experience now that market prices are higher than embedded cost prices, so if you have customers on this rate and they end up paying more for some reason than they would have under embedded cost rates, what do you do about that?

So what do you do? What works best? I think the answer to that depends on what your goals are, what your policy goals are. If your goal is to reduce usage at the time of peak demand, to cut utilities' peak demand and avoid building capacity, then we think that -- well, we have had the best luck with load control. It's pretty cost effective. The infrastructure is pretty minimal, and if that's your goal, then that may be the way to go.

If, on the other hand, your goal is to educate consumers about how they use energy and get them to think about making decisions on electricity usage, then pricing programs may be a better way to do that because that actually gives them a signal that they have to think about. We can debate whether it's useful for customers to think about pricing and react to it or to not think about pricing and have the technology take care of that. That's an interesting policy debate, but if you want them to be able to think about it, maybe pricing is the way to go.

Two more slides, then we will wrap up. As far as the question of mandatory versus voluntary, MidAmerican doesn't have a problem with this pricing being mandatory for large customers. The metering, the technology is generally in place today. Like I said, we have a significant number of our customers already on mandatory time-of-use rates. So we don't have a problem with mandatory time-of-use for larger customers.

As far as the smaller, more mass market customers, we don't think it should be mandatory. We think that it should be voluntary, but we do believe that if full scale implementation of this kind of pricing is desired for residential and commercial customers, there is a way to kind of make that happen on a voluntary basis, and we submitted some written comments in this docket previously that sort of outlined our thoughts on how some of that could be accomplished and I won't go into that in detail in the interests of time, unless somebody just wants to talk about that more. But we do believe that it's possible to design the pricing in a way that a lot of customers will naturally migrate to time-of-use pricing or to these time-based pricing programs, if that's the desired goal.

The last slide on cost recovery, the point here I'll make is that it's going to be really hard to charge the costs of metering infrastructure on a participant-by-participant basis because you can't really, in our opinion, put this stuff in one customer at a time. You can maybe do automated metering infrastructure neighborhood by neighborhood or town by town or geography by geography, but you really can't do it customer by customer. So it's sort of an all or nothing kind of proposition. And if you are not going to charge all -- if you are not going to have all customers pay a share of the costs of this kind of infrastructure, it's going to be really hard to get the thing paid for. I'll leave it with that. And I got 30 seconds for questions.

COMMISSIONER KOLBECK: Thank you very much. That was great. Commissioner Hanson, Commissioner Johnson, questions for Mr. Rea.

CHAIRMAN JOHNSON: Still formulating.

VICE-CHAIR HANSON: I'll just quickly say that I really appreciate all three of the presentations and learned a great deal and I thank you very much for being here.

COMMISSIONER KOLBECK: I do have one short question. Other states, when we were talking about mandatory or voluntary, do you know, are you familiar with other states that do mandate, and if you are, how do they enforce?

MR. REA: The only situation -- well, I am not aware of any state, it doesn't mean there aren't any, I'm not aware of any state that requires customers, large numbers of customers to take service under time-of-use rates. In Illinois there is legislation, it's either been pending or passed, I don't remember, that requires all utilities to offer residential real-time pricing and that's a legislative mandate. How they intend to police that I'm not entirely sure. That's the only instance that I can think of off the top of my head where something that detailed is being required for millions of customers.

COMMISSIONER KOLBECK: Thank you. Commissioner Johnson. Nothing? Staff, any questions? Well, that was a great job. I'll hand it back over to Commissioner Johnson, where we will wrap this up quick, and thank you all for being here.

CHAIRMAN JOHNSON: I certainly think, on behalf of the South Dakota Public Utilities Commission, I'd like to thank all of the presenters. We covered a tremendous amount of ground today and I didn't see a single person in the audience fall asleep, which is a testament to everybody. This was far more interesting than I thought it would be. And obviously a lot of very technical issues out there. I thought the presenters did a good job of laying out those issues for all of us.

Obviously this is just -- we are in the first steps of this process. I would ask all of you to continue to monitor our Web site for information on the docket. I know we are in the process of scheduling some other dates for the commissioners to discuss this. Yes, Rolayne, did you have something, Ms. Wiest?

MS. WIEST: Well, I was thinking that perhaps what we could do is the commission could actually put this docket on our agenda for Tuesday and then maybe just ask the parties if they had any suggestions on the best way to proceed from here.

CHAIRMAN JOHNSON: Ask that question on Tuesday?

MS. WIEST: Yes.

CHAIRMAN JOHNSON: Great, well, that is certainly fine by me. Let's go ahead and move forward on that, so that would be on this coming Tuesday's agenda. And again I would reiterate if anybody else that has any -- we are talking about procedure now, but moving again to the content of the issues, we are certainly still taking written comments on any of these proposed standards. Anything else, Ms. Wiest?

MS. WIEST: No.

CHAIRMAN JOHNSON: Thanks very much, and thanks for listening in on the Internet.

(Whereupon, the proceedings were concluded at 4:32 p.m.)

C E R T I F I C A T E

STATE OF SOUTH DAKOTA)
) ss.
COUNTY OF HUGHES)

I, Carla A. Bachand, RMR, CRR, Freelance Court Reporter for the State of South Dakota, residing in Pierre, South Dakota, do hereby certify:

That I was duly authorized to and did report the testimony and evidence in the above-entitled cause;

I further certify that the foregoing pages of this transcript represents a true and accurate transcription of my stenotype notes.

IN WITNESS WHEREOF, I have hereunto set my hand on this the 3rd day of May 2007.

Carla A. Bachand

Carla A. Bachand, RMR, CRR
Freelance Court Reporter
Notary Public, State of South Dakota
Residing in Pierre, South Dakota.

My commission expires: June 10, 2012.