MEETING OF THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of: :
: Case No. 09-778-EL-UNC
The FirstEnergy Service :
Company to Modify its RTO :
Participation. :

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Meeting of the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-E, Columbus, Ohio, called at 9:30 a.m. on Tuesday, September 15, 2009.

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COMMISSION:

Commissioner Alan R. Schriber, Chair
Commissioner Paul A. Centolella
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HEARING EXAMINERS:

Mr. Gregory Price
Ms. Kimberly Bojko

PRESENTERS:

Mr. Stanley F. Szwed, Vice President and Chief FERC Compliance Officer, FirstEnergy Corporation.

Mr. Michael R. Beiting, Associate General Counsel, FirstEnergy Corporation.

Mr. J. Craig Baker, Senior Vice President, Regulatory Services, American Electric Power.

Mr. Michael L. Kurtz, Boehm, Kurtz & Lowry, on behalf of Ohio Energy Group.

Mr. Andrew L. Ott, Senior Vice President, Markets, PJM.

Mr. Todd A. Ramey, Executive Director, Market Administration/Market Operations, Midwest ISO.

Mr. Jeffrey L. Small, Ohio Consumers' Counsel on behalf of the Residential Consumers of the State of Ohio.

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Tuesday Morning Session,
September 15, 2009.

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CHAIRMAIN SCHRIBER: We will call to order this meeting of the Public Utilities Commission. The date is September 15. The first order of business is I have no minutes to sign until later.

So the second order of business comes up, which is to address the issues in Case No. 09-778-EL-UNC, which is FirstEnergy's RTO Realignment proposal. We will ask each of six parties to give five-minute presentations. Then we will open it up for questions from up here.

First up is FirstEnergy. You have five minutes. Introduce yourself. We know you, but some others may not, but proceed, please.

MR. SZWED: Mr. Chairman, Commissioners, good morning. My name is Stan Szwed. I'm vice president of FERC policy and compliance for FirstEnergy, and today I'm here on behalf of our transmission only subsidiary, American Transmission Systems Incorporated, ATSI, and our FirstEnergy Ohio electric utility distribution companies.

I do very much appreciate the opportunity to be here and participate today and take the next few minutes to share with you highlights and our thoughts on the realignment and consolidation of all of our RTO participation into one RTO, and that would be PJM.

Hopefully you have before you our PowerPoint presentation, and I will use that as a guide to attempt to kind of go through. If you can turn to the slide on page 2, why do we seek to realign and consolidate all of our operations into PJM?

As you know, half of our company is already in PJM. Consolidating our operations into one RTO will approve our focus and internal operating efficiencies, and over the long run we think this is going to benefit customers as well.

In terms of our participation in MISO, as we look at our participation here, we are different. Our company is different. We have corporate separation of our electric distribution companies from our generation business. We have retail choice, and our distribution companies secure energy and capacity through competitive processes.

While MISO has developed really very fine good working markets, we believe as we look at the structure of our company and how we are organized, we believe PJM better suits our corporate structure as there are more participants in PJM that are more like us with more retail choice than things we see in the MISO footprint.

And also an important aspect of considering the move to PJM as well is the three-year forward capacity market that PJM has. And for a company that's separated like us into generation and electric distribution, corporately separated, we find that that process secures capacity and helps ensure reliability, while at the same time providing an opportunity for customers to bid and respond with demand response and energy efficiency programs in a similar manner as capacity supply-side resources have been.

If you turn to page 3, this is a graphic that depicts FirstEnergy's company's positions in the MISO and PJM RTO footprint. As you can see today, we sit right at the seam between MISO and PJM. We have depicted that with that red line that outlines the ATSI area and the seam that we have with PJM.

And you can see that it is quite extensive and it requires coordination to operate. And MISO and PJM have done a very good job in coordinating across that seam, but from our standpoint having all of our facilities in one RTO we believe will help improve our operations and simplify our operations and benefit customers.

If you turn to chart 4, slide 4, this was how the map, the picture would look, if you will, after the integration. The seam becomes in our mind more simple. It's now at the Michigan/Ohio border and basically from our standpoint, it is our three interconnections with the Michigan company, International Transmission Company.

So we see from our standpoint, hopefully from the RTO's standpoint as well, that that movement of that seam will help make it a little bit easier to coordinate.

If you turn to chart 5, this chart depicts the interconnection, the number of interconnections and the interconnection capacity that we have with MISO and PJM. And as you can see, we have significant inter-ties with a number of PJM companies, including one of ours, Penelec.

As you can see the capacity values are also very significant. There are 32 interconnections with PJM that we have versus three with MISO, and for the most part when you examine where we draw upon energy and capacity, much of that comes from the PJM side. In fact, if you were to look at the last three years and look at how net flows of capacity and energy into our ATSI footprint was, over 90 percent of it was coming from the PJM side.

So again, to align our company completely in the PJM footprint ties all of this together, and it aligns our interconnections as well as sources of supply.

The chart on page 6, one of the questions we get a lot is if you move to PJM, well, is it possible that energy prices are going to rise or change? I can't predict what energy prices are going to do in the future, but just stepping back and looking historically over the last three years, this chart depicts energy prices in MISO and PJM at various points.

I direct your attention specifically to the box that is highlighted in red there in the center where we show FE prices in MISO and just looking at that, comparing it to entities that are in PJM on the western side, which is more like us, you can see that the energy prices compare very favorably.

We would think that as we make this move, we shouldn't see much of a change, if any, in energy prices. In fact, in our filing with FERC, we did a little bit of an analysis that indicated that in looking at all of our generation being dispatched within the PJM footprint we see very little change in energy prices. It was a little bit more but virtually no difference.

On chart 7 I just want to point out that we have planned an orderly transition in this case. We are not seeking to transfer tomorrow or anything like that. We really believe in making this an orderly transition and making sure, working with both MISO and PJM, that reliability is maintained throughout the transition and that customers are involved and knowledgeable as to what is going on.

Our FERC filing contains an integration agreement with PJM, and that has some of the details of the specific activities and timing. One thing I do want to point out is part of the plan includes meetings with stakeholders, and the first stakeholder meeting will be held here in Columbus on October 2, so it is coming up.

The integration date we are seeking for transmission operations is June 1, 2011. As part of the process we also have to work towards aligning the meeting of the capacity requirements in PJM for the time that we start, up until the time that we are a full-fledged participant in the capacity market process. And we've worked out in the filing a plan to address that with a series of transitional capacity auctions that will provide capacity for the periods '11, '12 and part of '13 before we fully are aligned with the PJM capacity RPM process.

The very first point on here says January 2010 is the commitment date for PJM auction. That would be for the PJM auction that would take place in May of 2010 for the delivery years '13 and '14. The transition period covers the period between there so that we have sufficient capacity resources to meet the PJM requirements during that period.

As part of this transition, we will -- we have indicated this in our FERC filing as well -- we will fulfill our contractual obligations to MISO. These include exit fees and any other legal fees, such as costs allocated to us for transmission expansion.

We have one issue that we raised in our FERC filing with regard to the PJM transmission expansion. There have been a number of capital projects that have been approved by PJM and the board, and those projects are moving forward. We were not part of the footprint when those projects were planed and developed, so as we seek entry into PJM, we are seeking relief from not having those costs assigned to us. We will, as I said, continue to pay the MTEP costs and live up to them.

Lastly, the last chart just summarizes these dates with December 17 the date we have requested FERC to give us the ruling. The commitment date to the PJM capacity process is the end of January 2010; integration 2011; and then full alignment with the capacity market. As you can see, the transitional capacity auctions would take place somewhere in the April time period.

Just lastly, in summary, I'd just like to say that we are moving -- this particular situation, we are moving from one FERC-approved RTO to another FERC-approved RTO. We have been in MISO for over five years now, five or six years. We feel that moving into PJM better aligns with our company, the electrical configuration, as well as how we are structured from the standpoint of meeting the needs of the marketplace.

We really see there being benefits to the company as well as to customers over time here, and as I said, we have planned an orderly transition to make this hopefully smooth and efficient.

Thank you. I appreciate the opportunity to comment.

CHAIRMAIN SCHRIBER: Thank you, Mr. Szwed. We gave you a little slack as to the applicant, but we would like to keep it down to five minutes.

Number two, Midwest ISO.

MR. RAMEY: Good morning. My name is Todd Ramey, and I am the executive director of market administration in the Midwest ISO. In that capacity I oversee the operation of the primary market functions of the Midwest ISO, including the FTR market, the day-ahead energy market, and the realtime market pricing and validation functions.

I have been with Midwest ISO for eight years now and have been involved in various aspects of the markets from conceptual design through implementation and market operations. Through my career I have had the opportunity to publicly discuss various issues affecting the electric industry and have presented formal testimony and evidence before the federal regulatory commission and state commissions. I appreciate the opportunity to come and discuss this very important topic with you today.

My prepared comments this morning will focus on the issues and concerns we see with the FirstEnergy filing in FERC Docket No. ER09-1589, in which FirstEnergy seeks approval to withdraw from the Midwest ISO and join PJM. My comments today will also track similar comments and concerns that we will be raising in a protest that will be filed by the Midwest ISO in the FERC docket later this month.

In keeping with your schedule, I will keep these initial comments brief and summarize our lengthier filing, touching on some of what we believe to be the areas of most concern presented by the FirstEnergy filing.

I would like to make it clear and state from the outset that we recognize and support the voluntary nature of RTO participation and FirstEnergy's permissible right to withdraw, provided it meets its requisite contractual obligations, which we believe FirstEnergy has agreed to do in its filing.

That right to withdraw is not something that we will object to or oppose; rather, my comments and the issues and concerns raised today focus on the additional matters presented by FirstEnergy as rationale for the requested RTO realignment.

Let me turn now to the substantive areas of concern relative to the FirstEnergy filing. FirstEnergy's filing claimed various relative benefits of moving to PJM and included a production cost study performed by PJM at the request of FirstEnergy, purported to identify net benefits from that integration, specifically in the form of production costs and savings and lower congestion costs.

In our response to the FirstEnergy filing, we will dispute the accuracy of these claimed financial benefits and point out various flaws in the analysis that invalidate the findings of the study.

Further, we will point out that if the important aspects of the market design differences between Midwest ISO and PJM are considered in the analysis, the results would more than likely show a reduction of financial benefits. Examples of issues raised by the PJM production cost study include:

PJM's calculation of benefits includes $26 million in production cost savings and an additional $91 million in reduced congestion costs, suggesting a combined benefit of $17 million in annual savings. In reality the $91 million in claimed congestion cost reductions can safely be ignored because congestion costs or rents are refunded to participants in full via FTRs and do not represent a net cost to the market. Any resulting reduction in congestion costs would be fully captured in the claimed decrease in production costs. It follows then that any claimed reduction in congestion costs cannot be offered as a net savings or benefit.

The only potentially relevant results of the study then, the claimed $26 million savings in production costs, are driven by PJM's use of 2006 vintage hurdle rates; that is, the assumed financial transaction costs imposed on the model's unit commitment and dispatch decisions related to economic energy transfers between RTOs.

PJM acknowledges that recent improvements by Midwest ISO and PJM in administering the joint operating agreement, the JOA, have likely reduced the dispatch hurdle rate relative to the 2006 levels, but PJM assumes no decrease in the unit commitment hurdle rate because, as PJM states: "The market-to-market coordination process has yet to be invoked by day-ahead."

This assumption is flawed and appears to inflate the reported production cost savings. Since day-ahead market models are set up to reflect realtime operating conditions and outcomes, including the effects of JOA administration, the acknowledged improvements in realtime JOA administration have certainly been incorporated into the Midwest ISO's day-ahead model and are serving to improve efficiency of day-ahead unit commitment today at the Midwest ISO.

If these currently available unit commitment improvements were modeled correctly, the study results would be substantially less than the reported $26 million in annual production cost savings. Even at $26 million, this value, compared to the reported total production costs of 32 billion-dollar annually, is small enough to be within the margin of error for the type of production cost model used in the simulation and should properly be interpreted as a zero dollar net benefit.

Finally, with respect to the PJM study, due to the limitations inherent in production cost models like the one used for these simulations, the model fails to reflect certain efficiencies in the Midwest ISO energy and ancillary market design and operation relative to those of PJM that would have a significant impact on any valid comparison of total production costs comparisons between the modeled scenarios.

The more significant overlooked efficiencies include: One, the Midwest ISO uses a shorter dispatch interval of five minutes compared to PJM's 15-minute dispatch interval, resulting in more efficient congestion management and utilization of transmission capacity and requiring overall lower levels of regulation reserves and, therefore, the costs of regulating reserves than PJM.

And, two, the Midwest ISO co-optimizes the allocation of resources in both commitment and dispatch to simultaneously provide for energy and operating reserves requirements at least cost. Co-optimization is inherently more efficient and produces a lower overall production cost to serve the same load than does the more simplified energy and operating reserve procurement process used by PJM.

Taken in total, the Midwest ISO believes that a more accurate set of input assumptions and proper consideration of the relevant design efficiencies in the Midwest ISO market design would show a reduction in financial benefits of FirstEnergy's transition to PJM.

Another rationale offered by FirstEnergy to support the transition to PJM is the fact that FirstEnergy has more interconnects with PJM companies than with Midwest ISO companies and, therefore, participation in PJM will better align the RTO seam, lead to operating efficiencies, and reduce congestion.

Again, the design features and effectiveness of the JOA neutralize this premise as legitimate justification for the RTO transition. The JOA has largely attenuated the operational and financial impacts of the operating seam between RTOs. For instance, the JOA already provides access to the lowest cost resources along the seam to manage congestion, regardless of which are RTO those resources are in.

Also, the provision of the JOA provides both RTOs with access and rights to the combined contract transfer capabilities of the combined regions; therefore, FirstEnergy is effectively connected the same to the Midwest ISO as to PJM, both before and after the proposed realignment. The result is that the expected benefits suggested by the greater number of physical interconnections to PJM are already being provided through the JOA.

In short, moving the seam from one

location to another will not change the topology of the system, will not change the total number of congested flowgates to be managed, and given the current effectiveness of the JOA, will not result in significant improvement in reliability or operational efficiency.

The final point raised in the FirstEnergy filing that I would like to touch on is the assertion that lacking a centralized capacity market, generation in the Midwest ISO will exit the market and impair reliability.

It is true that the Midwest ISO does not have a centrally planned and administered capacity market like that used in PJM. Instead, the Midwest ISO long-term resource adequacy construct is based on establishing planning reserve margin requirements that must be met by each LSE, subject to financial penalties.

This approach to a long-term resource adequacy assurance has been used with success for decades by NERC regions and planned reserve sharing groups prior to the Midwest ISO's adoption of it. The construct also includes a 10-year loss of load expectation study, which will provide a forward-looking signal on future planning reserve requirements and congested areas of the Midwest ISO.

This process of long-term adequacy assurance was developed through close collaboration with the organization of MISO states and our stakeholders and was specifically designed to provide for the long-term reliability of supply that FirstEnergy suggests will be compromised.

There is no evidence to suggest that the resource adequacy is at risk for the foreseeable future in the Midwest ISO. In fact, the most recent Midwest ISO long-term resource assessment shows the Midwest ISO having a reserve margin of 25.5 percent in 2018 and a significant supply surplus in each of the next 10 years.

Again, the Midwest ISO does not oppose the right of FirstEnergy to withdraw its membership. We are a voluntary organization and the Transmission Owners Agreement specifies these rights. The Midwest ISO does, however, take issue with many of the justifications presented by FirstEnergy that purport to find generalized benefits of its proposed RTO transition.

We would recommend that this Commission either, one, press FirstEnergy to support and substantiate the claimed financial, operational, and reliability benefits resulting from the transition; or, two, give no deference or weight to any of these claimed general benefits when considering this important matter.

Thank you for the opportunity to participate and present comments on some of the issues that were raised by the FirstEnergy filing at FERC. We stand ready to assist the Commission in any way that we can with the important issues that are being raised and discussed today.

That concludes my prepared remarks, I would be happy to address any questions that come up during today's discussion.

THE HEARING EXAMINER: Thank you, Mr. Ramey.

That leads us to PJM

MR. OTT: Good morning, Mr. Chairman and Commissioners. I appreciate the opportunity to appear before you today to talk about the important matter regarding FirstEnergy's proposed RTO realignment. My name is Andrew Ott. I am senior vice president of markets at PJM.

As you know, FirstEnergy has submitted a request to the Federal Energy Regulatory Commission to withdraw the ATSI zone from MISO and integrate it into PJM. The implementation plan for integration was actually attached to FirstEnergy's filing, and there is also attached an agreement with PJM on how the integration would go.

PJM supports the integration plan to integrate the ATSI region into PJM and we are able to meet that schedule. It's technically feasible and certainly is able to be done in a timely manner. The proposed integration again promotes efficient transition and is designed to allow stakeholders and market participants ample opportunity to adjust their business plans through the transition period.

The proposed timing of the integration is well coordinated with PJM's RPM auctions and capacity auctions, with the allocation of transmission rates, financial transmission rights, and also with your Commission's anticipated bid solicitation for FirstEnergy retail customer standard offer service.

So this coordination will lower risk to potential suppliers because it will provide more certainty in the positions that they enter your auction with because the timeliness is coordinated.

The proposed realignment of FirstEnergy's operations into PJM makes sense electrically and will reduce the long irregular seam that currently exists in Ohio. Moreover, FirstEnergy's strong electrical ties with PJM will reduce congestion, increase operational efficiency across both RTOs, and result in more efficient day-ahead unit commitment of the ATSI zone generation

I want to again emphasize this efficiency gain is driven by the substantial difference in electrical interconnection rather than by any difference between the MISO and PJM day-ahead markets or any technical software capabilities. It really comes down to the physics of the system and the benefits of that more tight integration of electric generation into the RTO

The availability of FirstEnergy's generation for day-ahead commitment in PJM's day-ahead market would be the prime driver of reduced congestion and operational efficiency across the two RTOs. The proposed transition plan will both support and enhance the competitive retail process in Ohio by lowering barriers to participation by competitive suppliers.

PJM has implemented web portals with standardized data transfer protocols and centralized settlement and billing processes to allow daily load switching to support the competitive retail access programs, as we have in other states.

The FirstEnergy proposal to hold transition auctions to support the capacity procurement will increase potential capacity supply relative to the bilateral only option for the transition. The transition auctions are beneficial to Ohio customers because it will increase competitive supply and provide a more transparent competitive process for capacity procurement.

I have worked closely with the market monitor at PJM to look at the potential design of the transition auction, and he has found that it will be competitive, or at least the design will be competitive. Obviously I haven't looked at the auction itself.

As FirstEnergy has indicated, their proposed realignment will increase their transmission ties with the rest of their RTO from three ties, which it currently has, to 32 ties once the integration is complete. That goes essentially from 4,500 megawatts to 24,000.

As I stated earlier, this significant increase in tie capability with the RTO they are participating in will increase operational efficiency and will more efficiently utilize the transmission system, again because of the day-ahead scheduling aspect. It will also increase the pool of generation capacity resources available to the ATSI footprint to meet their installed reserve requirement. This increased capacity transfer capability will provide potential benefit to Ohio consumers and in the competitive retail procurement process.

PJM is committed to working with MISO, with FirstEnergy, and with this Commission to ensure an orderly, reliable, and seamless transition. And I'd like to thank you for the opportunity to speak today and look forward to any questions you may have. Thank you.

CHAIRMAIN SCHRIBER: That leads us to consumers' counsel.

MR. SMALL: Thank you. Jeff Small, Office of Ohio Consumers' Counsel, representing residential customers. It is a pleasure to be here today.

I'd like to begin with a bit of history. FirstEnergy was an Alliance member and selected MISO as its RTO for it to approve FirstEnergy's selection in July of 2002. Just a few years later, with basically the same transmission interconnections, FirstEnergy argues in its application at FERC that

PJM is, and I quote, "simply a better fit."

It is difficult to reach definitive conclusions based upon this history and FirstEnergy's recent filing at FERC. With all the discussions at FERC regarding which company should pay which charges, it should be remembered that retail customers will ultimately be asked to pay for the proposed changes.

At the very least, under the history of FirstEnergy's RTO selections, transmission rates that consumers would be asked to pay should not reflect charges, such as MISO exit fees, for FirstEnergy's change of business decisions.

FirstEnergy's proposal at FERC to leave MISO leaves many unanswered questions. FirstEnergy presents a study by PJM that was discussed earlier by the representatives from PJM and MISO, but that study does not examine all issues associated with the switch.

FirstEnergy's application barely mentions this joint operating agreement between MISO and PJM that deals with seam issues, and these issues appear to be important in evaluating the benefits and costs of the proposed switch. The PJM model does not deal with different requirements for generators under the

MISO and PJM footprints and possible effects of loop flow issues that will be the topic of a report to FERC in January of 2010

Most importantly, FirstEnergy's application provides little assistance in understanding which stakeholders will pay more under the proposed switch. The allocation of transmission development costs to Ohioans, both those from MISO and PJM, under the switch are very uncertain. Uncertain rate impacts would be felt on both sides of the MISO/PJM seam, not just customers of FirstEnergy in Ohio.

The proposed move to PJM may introduce uncertainty into a very successful competitive bidding process for the FirstEnergy load on June 1, 2011. The auction results for FirstEnergy load in May 2008 was very successful in lowering rates, well below those proposed FirstEnergy's ESP plan.

FirstEnergy apparently started with a June 1, 2011 implementation date and worked backwards to each of the other dates that are fast approaching. This is a significant change in RTO for the very same date when new transmission and generation arrangements will be needed for FirstEnergy's retail customers in Ohio.

Progressing strictly on FirstEnergy's timetable would provide the desired certainty for the next bidding procedure; however, the uncertainty posed by even a slight variation in the proposed timeline could introduce uncertainty and jeopardize the successful new bidding procedure in 2011.

FirstEnergy's proposed timetable is far too aggressive. FirstEnergy's application to FERC appears designed to force early cost consequences for a prospective move to PJM, consequences that would make it difficult to say no to completing the switch.

The first capacity market auctions related to the switch to PJM would take place in April and May of 2010, and preparations for those auctions would begin in February of 2010. However, execution of PJM integration agreements that would finally resolve the unanswered cost allocation questions would take places much later, in December of 2010.

Too many unknowns exist concerning costs that are not explained in FirstEnergy's FERC application. For example, the treatment of MISO exit fees should be understood before the commitments are made. The allocation of transmission development costs by MISO and PJM should be understood, both for committed projects and planned projects. In the worst of all worlds, Ohioans could be forced to pay transmission development costs to both MISO and PJM.

In conclusion, the actions needed to protect Ohioans in this matter would require much more time than is permitted in FirstEnergy's proposed timetable. I recommend that the PUCO obtain information on the likely effects of the switch on generation prices that customers would be expected to pay across Ohio. Obtain additional information on the allocation of transmission development costs to both MISO and PJM, and obtain information on the assignment of MISO exit fees to various parties.

Based on that information the PUCO should present its case to FERC that opposes plans that would unfairly treat customers in Ohio versus customers elsewhere. And if the switch is approved, the PUCO should ask FERC to state that FERC made no finding of prudence regarding FirstEnergy incurring MISO exit fees and that FERC does not determine that such fees were recoverable in rates

That concludes my prepared remarks. Thank you.

CHAIRMAIN SCHRIBER: Thank you, Mr. Small.

Let's see, Ohio Energy Group.

MR. KURTZ: Mr. Chairman, Commissioners, thank you for the opportunity. I'm Mike Kurtz for the Ohio Energy Group.

First of all, I'd like to say that FirstEnergy has been a very good supplier of energy to industry in northern Ohio and has done many constructive things, and we appreciate that, but this application raises serious questions about the cost impact on consumers.

What we have presented in this package is sort of a road map or strategy, if you will, to help assist the Commission in negotiating reasonable conditions and a reasonable time frame for any transition to PJM using your state jurisdiction over rates, not so much whatever you may say as an intervenor at FERC.

The first question to ask I think is: Do the three utilities that you directly regulate, do they have a choice in this? Is their consent needed, or is this strictly an ATSI matter? The answer is somewhat ambiguous from the FERC application, but the answer is probably yes, that the utilities do need to consent to this transaction.

I've attached various pleadings from the

FERC application where the utilities are referred to as transmission owner and they are directly involved in the FERC proceeding. The three utilities that you directly regulate, according to the FERC 1 data, which I have attached also, own about $700 million of transmission assets, so it's not that all the transmission assets are in ATSI. The three utilities do own significant transmission assets, CEI $406 million, Toledo Edison $33 million, and Ohio Edison the balance of $262 million.

So these utilities -- and they have to wear their utility hats. This is not FirstEnergy Solutions or FirstEnergy Services. These three utilities have to consent, it appears. And so then the question arises: Is this a good decision? Are the utilities making a good decision in consenting to transfer from the MISO market to PJM?

The evidence is certainly mixed. We heard from the MISO representative that the analysis made to FERC is flawed. What this analysis was, is it looked at the entire PJM and MISO footprint and found very, very small marginal savings to those two entire footprints. There was no study at all that I'm aware of where the utilities looked at the impact on consumers in northern Ohio.

The evidence -- and we would encourage the Commission to retain a consultant to look at this issue. But the evidence looks like -- and I'm not saying this is going to be the case. It's very complicated. But if you look at the available information, it appears that PJM is an inherently more expensive market.

If you just look at the energy pricing of PJM West versus the Cinergy MISO hub -- and there is publicly available data for that -- the day-ahead and the realtime pricing difference for the last 12 months was essentially that the Cinergy hub was $11 a megawatt-hour less expensive than PJM West.

I know that that's sort of anecdotal in the sense that you're going to have to look at the FirstEnergy area in PJM versus MISO, but to the extent that there is any differential, that is a significant drain on the economy of northern Ohio.

These three utilities have 60 million megawatt-hours of retail load. So every one dollar megawatt-hour difference is a $60 million a year drain from the economy. If there is only a one megawatt per hour increase in going to PJM from MISO, that's $60 million. $11 a megawatt-hour suggests $660 million. I know that's a very big number and

I'm not saying that is what it's likely to be, but it certainly raises serious questions for the Commission to look into, as to whether the utilities are making a prudent decision in consenting to transfer to PJM from MISO.

I've also attached forward pricing information where you see the same price differential. The PJM market appears to be more expensive than MISO.

Also the PJM market has an explicit capacity requirement that is paid to generation owners. It is the RPM, reliability pricing model. That is something that MISO does not have. The reliability pricing model, the intent of it, according to the PJM information that was stated here earlier, is to encourage new generation to be built. It pays extra money to make sure that there is generation supply there. It pays it to all the generators. And the logic is that the PJM area is generally a retail choice area and there's no obligation to serve and there's no requirement that utilities build generation.

Now, Ohio is really not in that. Ohio is more of a hybrid. In Ohio not only do the utilities have a provider of last resort obligation, but to the extent that they seek permission to get approval to build a power plant, they can get a surcharge for the construction costs of the power plant and a surcharge, a nonbypassable surcharge, for the operational costs once the power plant is built.

So there is plenty of incentive, and there's a mechanism built into Ohio law to ensure long-term adequacy of generation, and the RPM requirement that PJM has, it's an added cost that MISO doesn't that may be unnecessary, and it goes into the question: Are the utilities making a prudent decision?

In the sense of trying to give this Commission jurisdiction and leverage and bargaining power in negotiating for Ohio consumers reasonable conditions at FERC and a reasonable time frame at FERC for this transfer, the question comes then: Did the utilities make a prudent decision in going from one FERC-approved set of rates, MISO, to another FERC-approved set of rates, PJM?

And if they have made an imprudent decision, the law is very clear, and we have included citations from that. The law is very clear that the utilities would then be subject to a prudence disallowance under the prudence of choice exception to the filed rate doctrine, otherwise known as the Pike County doctrine.

This is very clear in the law. Let me just read from FERC. This is FERC itself talking: "In most circumstances a state commission may legitimately inquire into whether the retailer prudently chose to pay the FERC-approved wholesale rate of one source, as opposed to the lower rate of another source."

In the federal district court case, the Mon Power case, Monongahela Power versus Schriber is the case, in that case the federal district court recognized this Commission's Pike County authority to say to the three operating companies: You chose the wrong FERC-approved rate. You chose PJM, and you should have stuck with MISO, if that's what the evidence shows, and we don't have any evidence on that.

But if it was an imprudent decision, then the utilities would be subject to disallowance for the costs that arise from that imprudent decision, which would clearly -- which could include the transmission costs, as well as the generation costs that result from it in any future auctions.

So with that prudence of choice authority that this state commission has over the resulting rates from the choice of the utilities, that is what we think is the area where this Commission has the most authority, the most clear jurisdiction, and the ability to protect consumers in northern Ohio best by requiring reasonable conditions and a reasonable time frame on any transition to PJM because of the threat -- not the threat -- because of the possibility that this decision may be imprudent and may result in higher costs on consumers.

Again, I do want to stress that I'm not saying that these costs are going to be higher. It's a very significant question, and the three utilities that you regulate have provided no evidence that they won't be higher, and that I think is a serious matter for the Commission to consider.

Thank you.

CHAIRMAIN SCHRIBER: Thank you, Mr. Kurtz.

Finally, Craig Baker from AEP.

MR. BAKER: Good morning, Mr. Chairman and other Commissioners. Given the time, I hope to give you some back. My prepared comments are not prepared and they're not going to take very long.

My name is Craig Baker. I work for AEP

Service Corp, and I head all our regulatory services, but maybe more important for the discussion today, I'm the lead officer for AEP in dealing with the three RTOs that we belong to. So we have the luck of the draw of being in our RTOs and seen a lot of different things.

We support the voluntary nature of RTOs, and the companies should be able to choose the RTO that works best for themselves, their customers going forward.

As with any filing, I think this filing raises more questions than provides answers, and that's going to be the gist of the comments that we provide to the FERC. I think the answers will be forthcoming. There is a good process, and we will be going through customer meetings. There will be meetings at the FERC, I'm sure, and a lot more information will be developed during that period.

We will be there looking at what the impact on our customers are, although I will note that generally our customers are not impacted by the impacts resulting from the capacity and energy markets of PJM because we deal with the FRR, which is the fixed resource requirement. We bring our own capacity, and generally our energy is supplied by our own generating resources; therefore, our customers tend to be pretty insulated.

Congestion, on the other hand, does have an impact, so that will be an area we will want to see more information on. So we will be active in the process. I'm sure you all will be as well, and I look forward to further discussions this morning.

CHAIRMAIN SCHRIBER: Thanks, Craig.

Okay. Why don't we start asking some questions. We have some I'm sure. I'll lead off, and then we'll go down the bench here.

Congestion seems to be a pretty huge issue. Craig, let me ask you this because maybe you have, because of the position you're in, I don't think you're taking any strong position, maybe educate us a little bit.

With respect to congestion, you hold FTRs. Everybody in PJM has FTRs which have value. By introducing FirstEnergy and their generation into this mix, does this devalue, alter the value of those FTRs to you, and is that a concern?

MR. BAKER: It is a concern because the value of the FTRs we actually use as a credit toward our customers' transmission costs that we flow through in our transmission rider. I think you have to look at this in a couple of steps, Mr. Chairman. The first is there is the ARR, FTR allocation process, and I don't think we need to get into ARRs and FTRs. The most important thing is that people ultimately end up with FTRs.

And we don't yet know whether this will increase the amount of FTRs that the companies will get or reduce it. That will be something that will be determined based on what the impacts of the flowgates are moving in the JOA, as I understand it.

Then once you get them, then there's a question of in fact if there's reduced congestion, does that create a situation where the individual companies and therefore their customers are either -- net congestions cost, which is the difference between the congestion that they pay for serving their load and the value they receive from the FTRs, whether that net congestion goes up or down. So that's one of the questions I think needs a little further analysis, both on one step and two.

CHAIRMAIN SCHRIBER: Mr. Ott, since this is your domain, do you have any knee-jerk reaction to that?

MR. OTT: Yes. I think that the transmission rights allocation process, which essentially is looking to provide the ability for customers to be hedged based on the fact they pay for firm or network transmission service, that process generally with the integration of a new zone historically has resulted in that zone providing -- getting the full amount of FTRs available to them consistent with what their deliveries from the network resources are.

Again, until that actual allocation is done, I can't give a definitive answer, but what we have seen, generally speaking, is the phase one of that allocation, which is for the firm resources to load, has generally been 100 percent feasible.

As far as the value of -- we can easily do such allocations and look at power flows around that. That is not something that's a mystery. So if there was a need to do a sample allocation, for instance, we could certainly do that and provide that information. That's not something that is unmanageable.

But the second is the value of the transmission rights, the dollar value of them. And, again, the key here is that when the congestion -- if congestion would go down and what our analysis indicates it would because, again, the day-ahead market coordination of those resources due to strength of ties would, in fact, make it somewhat easier to preschedule generation to help congestion realtime.

It's not a lot of dollars, but it is some dollars. But for every dollar you have a reduction in congestion, you may have a corresponding reduction in the value of the transmission rate, but they should net to effectively having a similar impact on the customer.

Now, to the extent the customer is unhedged, meaning the merchant got transferred, this competing with serving others, that would be a benefit.

Now, of course, as was stated earlier, the $91 million reduction in congestion is not a complete benefit because there is some hedging there. But what it was really was a measure of efficiency of operation. In other words, instead of looking at this and saying this is the dollars going into someone's pocket, it's actually a measure, an objective measure of what is the gain in efficiency. That's really what it was about. So value-wise, the FTRs are probably a wash.

CHAIRMAIN SCHRIBER: Thank you.

Mr. Szwed, in your second quarter report of financial last earnings, your energy prices or your energy sales obviously were off second quarter, as we all know, for about everybody. But there's significant positive offset by capacity sales in those divisions of yours that belong to PJM.

If that were to be the case with the Ohio operating companies, would we expect those capacity revenues that would offset whatever sales deficiencies there are, would we expect to see any of that flow through to Ohio customers, or would that put a demand on -- would that put any pressure upward on prices?

MR. SZWED: That's a good question. I think I'm not -- on the other side where that's happened, I think I don't believe those are offset. In the Ohio situation, I'm not exactly sure what would happen in that case. I guess it might be a function of what is the source of that capacity. I mean, is it our own regulated affiliate, or it something else?

CHAIRMAIN SCHRIBER: Okay. So I'm just noting here that your lower sales value $57 million and energy prices of $15 million in the second quarter of '09 compared to the same period last year are partially offset by higher capacity revenues or 61 million resulting from higher capacity prices, I'm just wondering how that offset flows through, if any.

MR. SZWED: I'm not sure how that would work.

CHAIRMAIN SCHRIBER: Okay, I can understand that.

Mr. Szwed, again, if you had two issues, you go from MISO, that's a fee, and then you have the RTEP fees. If FERC goes one way or the other or both ways, doesn't let you out of either or asked you to do one or not the other, is there any combination or permutation that would cause you to vacate this filing?

MR. SZWED: Our first point, we don't think we should pay double.

CHAIRMAIN SCHRIBER: Understood.

MR. SZWED: Doing both right now, we don't think we should pay double. Our philosophy is if we are in MISO and we have had costs allocated to us and so forth, we would continue to pay those, and we believe those are right because those are what are obligated by the arrangements and agreements and I believe the tariff as well.

If FERC were to order something different or indicate something different than what we have sought, like any other FERC order, we would have to step back and take a look at that. The RTEP costs for facilities that were planned and developed when we weren't there are pretty significant. We would have to step back and examine whether it would be appropriate to continue or not. Our position we shouldn't pay both. We shouldn't pay the PJM RTEP legacy piece.

CHAIRMAIN SCHRIBER: Let me pass it down the line.

COMMISSIONER FERGUS: I have one question. This is for you, Mr. Szwed. It seems like all the justifications for this transfer to PJM are really justifications that would have been relevant at the time you made your initial decision to go with MISO.

And I'm just wondering what has changed since you made that decision to the time you've made this decision that now makes you believe that this is the better fit?

MR. SZWED: Yes. There is a lot of history that goes back with the development of the Alliance. RTOs, as Todd said before, there is a lot of history with that. Back then when we made that choice, there was a lot of continued developing of RTOs, if you will, and FERC in a sense when the Alliance did not get approved, FERC was indicating perhaps we should consider the Midwest ISO, and we did.

We moved in that direction, and at the time our company had been part of that particular region, the ECAR region. We weren't part of PJM and the Mid-American region. We thought over time as RTOs evolved, there would be a lot more similarities, a lot more comparability, a lot more being very, very similar.

In fact, one FERC initiative was trying to create standard market design where there would be say standard market design across all RTOs, and that didn't quite develop. MISO and PJM over time have orchestrated a very good joint operating agreement, really worked hard to develop protocols and so forth.

But what we are seeing in terms of our situation today is many of the participants, most of the participants in MISO are really part of what we call hybrid companies, and a lot of the -- in our opinion, a lot of the structure that goes around the markets and so forth really are more for that.

As we look at our company, the way we

have separated our generation from the distribution business, and even in the access side, the transmission side, we find ourselves as we look at this, particularly again from the market standpoint, more aligned with many of the companies and their structures in PJM and the retail choice that exists in PJM.

So if there is one change it's really that direction of how things have evolved on both sides where we believe that for our company and from our standpoint and our footprint we really feel that PJM provides a better fit for us from the standpoint of being able to accommodate competition on the retail side.

CHAIRMAIN SCHRIBER: Ms. Lemmie.

COMMISSIONER LEMMIE: Good morning. We certainly appreciate everyone's presence today, and their availability to respond to questions and comments from us.

I'd like to start by saying that I am most concerned about the cost impact to Ohio ratepayers, both within the FES ATSI footprint and statewide. I'm also concerned about to the extent there are benefits, who will be the net beneficiaries of what efficiency savings and production costs there might be. Does that go to stockholders, or does that go ultimately to those customers who are using the service?

So I'd like start out by having you talk a little bit, if I could, Stan, about the fees that you will have to pay to exit one RTO and enter another, generally what those dollar amounts are and who will ultimately pay that? Is that a cost you will pass through to those who purchase the generation, or is that a cost that the company in its business decision will absorb?

MR. SZWED: Yes, there would be exit fees and integration fees. The exit fee, our planned exit wouldn't happen until May 31, June 1 of 2011, so the actual number for the exit fee will be calculated as we get close to that period of time.

The integration fee into PJM, attached to the filing there's an integration summary. In the plan it delineates the various components of the integration fee. I believe the integration fee to come into PJM is just a little bit under $12 million. It's, I think, $11.6 million split into a capital component and O&M component, some of which is directly paid by FirstEnergy; some of which would be paid by PJM.

To answer your question about how we propose to collect that or how that would work, our consideration right now would be to propose recovery of those dollars when we file an update to the ATSI transmission rate which we have currently in MISO.

The plan would be to file that rate sometime in the 60 to 120 days prior to the integration date, which would put it around the 1st of 2011. As you know, that rate is a formulated rate. So to the extent things change, new property gets invested or expenses are lowered or raised, that rate is adjusted every year. So we would propose to integrate or to include the numbers associated with exit as well as integration, however that worked, and deal with that in that particular case.

Also recognize that in terms of that rate, it also takes into account when we have efficiencies and reduce O&M costs and change operating practices. Those things do flow through to that rate as well, and we do see operating benefits from our company's standpoint going from two RTOs to one.

I will give you a couple of examples. Today our company participates in two RTOs, and we appreciate Craig in three, but we have a lot of people scattered dealing with a number of issues. Just in my group alone, from more of a policy perspective on this, there are three people dedicated to each side. As we look at planning and operations and settlements and other financial things, there's a lot of people throughout our organization that are involved in that.

From a reliability and compliance standpoint, given with NERC, just in the course of the last two years, given we are two separate footprints, we have had five various types of reliability audits. We have two separate reliability coordinators. We have in some respects two separate types of operating practices and rules that we have to follow.

I think over time as we integrate into one and combine our operations, it gives us an opportunity to focus on one set of rules, one set of protocols. To the extent there are cost savings and reductions in that regard, those are transmitted -- they flow through the formula transmission rate that we have on file, which as we integrate into PJM we expect to continue.

COMMISSIONER LEMMIE: I'd like to follow up on a comment that was made by one of our other presenters, Craig Baker at AEP, who talked about net congestion costs, and also a comment from Mike Kurtz, and Mike talked about the prudency issue and the responsibility of the three utilities that we currently regulate on the retail distribution side. Your comments and thoughts about what he had to say, and I'll get back to the AEP comments.

MR. SZWED: Just as a comment, I think with our company situation, you have to step back and look at our companies, and they are distribution companies, and distribution companies don't own generation.

I think it puts our situation in a little different light. I think in terms of trying to acquire energy and capacity to provide service, particularly for the POLR load situation, I really think in our structure moving forward to more of a competitive type environment I think we have seen this over the last year or so in terms of what happened there, we think is positive, and we think PJM in that regard provides that type of environment to better suit that for us and for our customers.

I think on some of the discussion with regard to congestion and what was included in the study that we filed, I think from our standpoint, we wanted to include an analysis in there that provided some indication as to what it might mean. We can't forecast energy prices with a degree of accuracy. We don't know, because in our situation we are relying on the market.

I think for PJM to run that study and to give us some indication of what happens when we do integrate ATSI and the rest of our companies into PJM, what would happen, I think we see some positive numbers there. They're small. But I think if you change some of the assumptions and undid all that, I think the worst that could happen is no benefit shown by those studies.

But I think there is an opportunity. I think as Andy said, that there's an opportunity to achieve some of those, but, again, we have to get there to demonstrate that.

You know, I think as far as the utility -- our utility companies go, I think in terms of how we look at it in terms of that perspective, of how do we best position our companies to obtain the most competitive type of market pricing available for customers, and we think that having that in PJM will work better for us in that capacity release.

COMMISSIONER LEMMIE: Lastly, before I

pass on to my colleague, Andy, you mentioned if we needed additional information or data, you could provide it. What about cost data on the impact of the move on ratepayers in Ohio, whether they're in MISO or PJM? What kind of analysis would be necessary, and is that something you could generally provide, even if it requires input from the staff of the PUCO?

MR. OTT: Well, certainly the integration costs, as indicated by Mr. Szwed, we have an estimate of that cost and those estimates are being revised as we continue to move forward with the project planning. Certainly those data are available.

If you look at just admin fees, administrative fees, of the two RTOs, certainly there is a slight reduction in admin fees. Again, these are very small dollars between the two. And if you look at the move of FirstEnergy into PJM, they pick up a certain amount of our admin fees and reduce admin fees for other Ohio utilities, for instance. So type of information we could make available as far as admin fees go, if that would be helpful.

CHAIRMAIN SCHRIBER: Commissioner Centolella.

COMMISSIONER CENTOLELLA: Thank you, Chairman Schriber, and thank all of you for coming in talking to us about this subject today.

I guess I want to begin with looking at the question of what impact does this have or may this have on Ohio consumers, and I want to start by looking at this question of the study that was provided.

Stan, did I sort of understand your last answer to be that you know these numbers are really pretty soft, we can't know from these numbers whether there are operational benefits?

MR. SZWED: Andy can speak to the study better, but in terms of our filing and so forth, we wanted to provide what it might mean if all of our assets and resources were part of PJM and dispatched in PJM.

I think what it shows us is that we're not seeing a negative situation where there's a dramatic harm or negativity to customers. We are seeing potentially some positive benefit. I think if you potentially alter some of the hurdle rate assumptions that we discussed before, you possibly could lower those benefits. But at the end of the day you see some benefits and certainly see if you move to PJM, we certainly see the opportunity to achieve some of those benefits as you move forward.

COMMISSIONER CENTOLELLA: Do you disagree with what Mr. Ramey indicated, that 25, 27 million dollar benefit is really in the error band?

MR. SZWED: Even in the filing, we showed that the number .06 percent difference on the energy side was very small. Frankly, as I said in my comment, that I could not comment on what we have seen historically by looking at those prices in and around, you know, MISO and the Western PJM shown on the one chart I had in my packet.

So I think there is some consistency there. If we are looking ahead versus looking a little bit in the past, I think there's a consistency there and we shouldn't really see much change in energy prices. That's what I get from that. And Andy could add more into how he feels about it from PJM's perspective

COMMISSIONER CENTOLELLA: Andy, you have to anything to add?

MR. OTT: Again, the study was to try to put a metric, a measure on what is the efficiency gained. If you look electrically -- obviously, I'm an electrical engineer. I'm a system operator. If you look and say I now have an order that's 32 ties and I change that to three, there is an efficiency gained there. The PJM/MISO joint operating agreement works wonderfully, and I agree with Todd, in realtime we are doing a great job in coordinating our realtime markets.

However, there are barriers that prevent us from doing day-ahead coordination. Some of those are barriers in the way we both approach our day-ahead markets. Some of those are simply if I make a decision day-ahead that I need to pay MISO to move a generator, then I'm making a decision that could be construed as taking a commercial position in the market. So that would require a fair amount of discussion in the stakeholder process to get to that, and I'm not sure that it's completely feasible to do that 100 percent of the time.

The point there is this was a measure to say what we are leaving on the table essentially by not getting to that complete integration, which would be essentially merging the two markets together, and that's what this was. I don't think -- as you say, if you look at the impact of the transmission rates, allocation process, meaning you have -- if congestion changes, some of that is hedged by transmission rates; some of it isn't.

So if your question to me is will that $91 million we quoted go into the pockets of consumers, the answer is, well, no, because they're already hedged to some extent for that. But if the statement you're looking for is does this show that there is some efficiency gain, because of the data I think the answer is yes.

I don't think you could reasonably look at this and say if you go from a complex scenario to a less complex one, you can't see some efficiency gain. I think that what the study was trying to show, you certainly can change assumptions, but I don't think you will see changed assumptions to reverse the finding which would say you would see cost increases and that's the point.

COMMISSIONER CENTOLELLA: Mr. Ramey, do you see any possibility if the assumptions were changed to, for example, reflect the regulation requirements or the co-optimized markets in MISO, that we would see a potential change in the results the other direction.

MR. RAMEY: I definitely think we would. But before we move to those more technical nuances and energy market differences between MISO and PJM, I want to respond to a couple of points that Andy made.

One, he makes the argument that on its face that FirstEnergy having ten times more interconnects with PJM companies than with Midwest ISO companies on its surface suggests an opportunity for increased efficiencies with FirstEnergy's participation the PJM.

Well, that would only be true to the extent that today's day-ahead market models included some sort of constraints that represented physical transfer capability, FirstEnergy and PJM versus MISO.

The market models don't contain those kind of contract path or physical capability interconnect type constraints. Again, the JOA provides for the joint use of whatever transfer capability is provided in the region. Whether it's MISO's use, MidweastISO's market use, or PJM's market use, the rationing is accomplished through specific congestion management on specific flowgates that are binding between the two regions along the seam.

So on the surface it may seem intuitive that a stronger interconnect means the opportunity for more efficiencies from FirstEnergy's participation in PJM. In reality, the JOA and the way the constraints are set up in the market models, there really isn't a restriction today based on the fact there is a weaker physical energy interconnect with FirstEnergy to Midwest ISO.

COMMISSIONER CENTOLELLA: I want to come back to a point. Stan, you said the LMP between the two markets were similar, and you point I think to chart 6 in your presentation. What is included in those LMPs that you are citing there? Does that include capacity and ancillary service costs, or are those just energy costs?

MR. SZWED: I believe they're just energy.

COMMISSIONER CENTOLELLA: If we take a look at the capacity markets here, and there are some significant differences of the capacity constructs between the two RTOs, first of all, we heard Mr. Ramey indicate that they will have 25 percent reserve margins in 2018. Mr. Ott, where are you in PJM in 2018 in terms of your reserve margins?

MR. OTT: Given the economic downturn, I think -- I know it is above 20 percent. I don't know -- I don't have that information in front of me. But with the economic downturn and the significant updates in the loads, I think we're all experiencing rather sharp increases in reserve market because essentially you're seeing the loads go down, and you're still seeing some generation come in to some extent. A lot of it is the intermittent type. But I think there's a similar outlook, which is a fairly significant reserve margin.

The other thing I point out, though, is in PJM there is a significant difference between the western side of PJM capacity supply/demand balance and the eastern. Obviously, if you look at the state of New Jersey, eastern Pennsylvania, Delaware, the capacity outlook there is tighter. You're seeing reserve margins down in the teens.

When you look on the western side of the market, it is substantially different. Then you're up in the 20s. So you have to keep that in mind. When the statement was made PJM is a higher cost market, well, it really isn't. If you look at the western -- in other words, if you look at the PJM western hub, which includes parts of the eastern part of Pennsylvania in it and it also includes the Baltimore, Washington area to some extent, that price includes some of the congested parts

If you look at Ohio, and there are some forward contracts available for the AEP zone, if you look at those forward contracts, they almost lie on top of each other. There really isn't on an 18-month forward a significant difference in price.

Now, there's a huge difference in volume. The PJM contracts generally have much higher volume. I think some of the reason you're hearing from FirstEnergy it supports competition, there are just more players out there trading. I think you have to be careful to jump to the conclusion that the PJM market on its face is more expensive. You have to look at Ohio, and I think you will find it really is not significantly different. And you wouldn't expect it to be because of the strength of transmission ties.

COMMISSIONER CENTOLELLA: I guess I'd like to wrap up by asking other panelists, if they could, to comment on the differences between the capacity market in PJM and MISO and what your thoughts are about that, given that we have a very structured forward capacity market in PJM with these three-year auctions and the incremental auctions for specified requirements, and we have, I would say, greater flexibility in MISO for parties to enter into contracts and different links to secure their capacity and whether or not you have comment to offer to us at this point about which capacity construct, you know, may be more economical and more consistent with consumer choice, starting with Mr. Kurtz.

CHAIRMAIN SCHRIBER: May I introduce one other question into your question? Demand response, how that plays out in the respective markets.

MR. KURTZ: Let me comment by saying this. One question that has been asked a couple times is what has changed since the three utilities that you regulate decided to join MISO. An done significant thing that has changed in 2007 that's when PJM introduced the RPM explicit capacity market.

That explicit capacity cost, if the three utilities are allowed to move from MISO, will be paid by all 2 million consumers in northern Ohio, whether they shop directly or take power through the auction. And that capacity revenue will essentially be paid to the generation owner, FirstEnergy Solutions, that owns the generation that you don't regulate.

So without a study by someone, by the utilities, by a consultant that's hired by the Commission, I don't know that you'll know the answer to that very, very important question of which capacity cost is less and what is the prudent decision. So right now there's a big blank, and I think that the utilities have the burden of proof on that to show that their decision is prudent.

On demand response, I think PJM has a far more developed demand response program for large users than MISO.

MR. SMALL: I'll just make the comment that you asked about the different pricing constructs in PJM and MISO. I'd just like to address the commentary by FirstEnergy in its FERC application. It states that it is not making a criticism of the manner in which MISO operates as far as planning, but I think it is making that criticism.

It is making it, and I heard the comments again today, that MISO is essentially not doing its job. That's the way I interpret the comments. In not having the capacity markets, they're not doing their job as far as planning for the future needs of the region.

I think that's an unsubstantiated claim and I think there is this implicit criticism of the MISO construct in the FERC application, and I don't think it's substantiated at this point.

COMMISSIONER CENTOLELLA: Mr. Ramey, anything?

MR. RAMEY: No. I would tend to agree with that. We have different philosophies between the two RTOs and how we're monitoring and ensuring long-term supply and resource adequacy. Through long discussions with our stakeholders, Midwest ISO working closely with the organization of MISO states, with significant leadership from the PUCO, we arrived at a construct that allows for MISO to do forward-looking planning, to make assessments of accuracy, and address areas in the future where we think there might be supply adequacy concerns.

We turn that information over to our loads, working in consultation with our state commissions to address the best ways to move forward to mitigate those identified concerns. MISO certainly respects the responsibility and authority of our state commissions in ensuring and working with our regulated loads and determining the best path forward and answering those long-term supply resource decisions.

I would tend to support there are different approaches, but there's no reason to believe the Midwest ISO's resource adequacy construct in any way should jeopardize reliability in the future related to long-term supply.

MR. SZWED: Let me just be clear, we are not criticizing MISO here. There's a resource adequacy mechanism, and it works there. It's just the footprint, the construct of the footprint in MISO is just dramatically different than what is in PJM. You have a lot more states that are fully regulated, a lot more participants that are regulated. A lot more of the generation is included as part of ratebase, and reserve margins are worked through and set in conjunction with the state commissions.

In our situation for our company, again, coming back to the fact we are our -- our electric distribution companies are corporately separated from generation puts in our mind a little bit different wrinkle of what we need to do.

As we look at PJM and look at the RPM capacity construct and the way that market is managed for companies like us for the situation we are in, we believe that provides a better mechanism to secure capacity for the footprint.

And by that I mean PJM goes out and secures a certain level of reserves, per the reserve criteria, which is applicable to the entire footprint, and goes out and secures that capacity, and then that capacity is available to all the participants within the footprint.

And to the extent customers switch from

one retail supplier to another, the capacity comes along with it. It's a three-year forward market. It's a very transparent open market. In our situation it provides that transparency for suppliers who then come in and bid to our POLR auctions that are held in Ohio.

That's one of the reasons we set up the time line here the way we have. You know, the next POLR auction here in Ohio is June 1. The next time the rates change are June 1, 2011. We wanted to provide an appropriate transition period so that suppliers in that next upcoming auction, whenever that is, has the benefit of knowing that capacity is going to be for the 11, '12, '13, '14 period, if you will, by virtue of the fact of how we structure this in our integration to PJM.

So we feel there's from our standpoint, our viewpoint, a lot of benefits to have that; one, to secure the reliability as well as provide having the openness and knowing what that capacity value would be so when POLR suppliers bid into the POLR auction, they can reflect that in their bids, and, in fact, in many respects that should lower any risk premium in that bid because they know there is a certainty about what their capacity payment is.

COMMISSIONER CENTOLELLA: Are you suggesting that the POLR auction you had this last year was unsuccessful?

MR. SZWED: No, I'm not. We are looking in terms of moving forward and the way we see it from our company's perspective is taking that and, obviously, working through this integration to PJM to improve that process, make it another component, more transparent, more available, and more open for that so then POLR bidders when they put together their bids, they know what the capacity is for our situation.

COMMISSIONER CENTOLELLA: Mr. Baker.

MR. BAKER: Well, I think when I look at it, either way I believe will ensure reliability. Whether you administratively set it or you do it via market, we will have the capacity. I'm comfortable with that. The question is, is what is the cost impact associated with the two different approaches.

I'll give you what we did and then you can draw your own conclusions. When RPM was proposed by PJM, AEP looked at it and decided it didn't fit the model of AEP. And the reason is that AEP expected to be building capacity in order to meet its load and meets its reserve requirements.

The PJM model is an administratively determined supply/demand curve, which means that if the reserve margin is expected -- needed to be 15 percent, just for using numbers, it could clear at 19 percent. It could clear at 11 percent, and the price will vary.

What we wanted to do was to be able to see if we come in with the equivalent of 15 percent, we should be exempted from whether the market moves to 19 percent or 11, we'll show up with the 15 percent. So that was a choice AEP made. We pushed hard and we are successful in getting the FRR, and it has worked for us.

Others clearly have seen in a state where there is complete separation between generation and load-serving entities, I think there is support for the fact that the market approach gives a little more transparency.

COMMISSIONER FERGUS: Commissioner Roberto.

COMMISSIONER ROBERTO: I am grateful to all of you for the time you have taken this morning to share your insight. I think each of you has succinctly provided a very quick overview. As a result of this morning, I'm afraid we've just opened more questions than answered them. It would be tempting to sit here throughout the morning and get further and further in the weeds to really examine which is the better market, how will it work for ratepayers.

But I think from my perspective those are questions that are fairly key. I guess, Mr. Szwed, the only question I would pose at this point is that from the filings, from the conversation this morning, it appears to be a certainty there would be at least an exit fee that would not be required but for this transition. We don't know the magnitude of it, and we won't know that I think you said until maybe 2011.

There's certainly going to be questions that come out of the allocation of the development costs, whether or not consumers will in fact have to pay both, in both RTOs. There are questions that go to whether or not the capacity market works better for consumers versus the reserve market.

None of those questions can be answered anytime soon, yet the three distribution companies in FirstEnergy have seemingly answered that question already by their filing at FERC, and my question is how can we be certain as commissioners who will be at some point required to look at that judgment they've made and review it for its wisdom or prudency, whether that's in the context of an inter-utility contract we need to approve or a future request for recovery under the transmission rider, as you suggested that these costs would flow through to, particularly in the light of the fact that it's difficult for me to see how they would not be influenced by their sister companies and how this might be of much greater benefit to the sister companies who actually own the generation.

MR. SZWED: Well, I think a couple of points here to make. First of all, in terms of your points and questions on costs, the way we really kind of look at it, and we talked about this to some extent today, the energy prices, we don't know exactly what they're going to be, but looking at history, looking a little bit at some of the analysis that was that done, and comparing it to the right comparison, we don't see much of a change in energy prices.

There is the opportunity, as Andy has pointed out, as we talked about in our FERC study, the possibility for increased efficiencies, and it's just not about the congestion piece that's in the analysis. It's about some of the things I've talked about before from our company focusing on one RTO, perhaps, eliminating some of the duplication that we have across the company.

I think on capacity is another cost. I think the one thing I can say about PJM, we know we would know what the capacity is. I think that's a good thing from our company's viewpoint.

In MISO there is a capacity cost, and capacity is being paid for. They're either embedded in rates because of cost of service and generation is included in a regulated utility's ratebase, and there's capacity being paid.

But what you don't know for sure what the number is, and sometimes you just can't make a direct comparison what the capacity value is in PJM and what the capacity value might be in MISO. But what we do know about PJM that it is open and transparent. From a capacity standpoint, you will know three years ahead of time what the capacity is.

The second piece to that capacity thing, which I think is of benefit to customers, particularly customers in our situation, in our footprint because of the way we're structured and the competitive effort, is the demand response program and the energy efficiency program that exists in PJM.

Customers can bid into marketplace. Their demand response situation, in fact, this past year if you look at the most recent RPM auction, a significant amount of DSM was bid in. And those entities who clear their programs get compensated directly, just like a generating-capacity supply bidder would get.

And I think that is of great benefit. It's a great benefit to customers. It's a great benefit to the company from an operating standpoint as well because it gives us additional resources and ways to use our facilities and plan our facilities.

On the RTEP, MTEP issues, in our mind our policies will clear under that. We believe we have an obligation upon exit from MISO to pay the MTEP charges and continue to incur those. The issue we have is moving into PJM, we were not there when those new facilities and their plan was approved. They've moved forward, and we don't believe we should pay those, essentially pay twice for MTEP and RTEP.

Going forward in PJM however, to the extent there are new projects planned, approved, once we are integrated, we obviously would be subject to RTEP charges and costs, cost allocations. The fact there are projects that span across both RTOs, the

RTOs today have cross-border allocations, and irrespective whether we are in one or another, if it's determined that there's cross-border allocations on projects, we could still be subjected to those.

So in that light, as we step back and look at this, we find that there are benefits. Yes, there are some costs, but I think the costs are also -- have the potential to be offset, particularly on some of the operating efficiency pieces that relate to transmission, because, in fact, there is a formula rate that we could automatically pass though those.

I think as Andy pointed out and as I said in my remarks, I think there are market opportunities there from customer standpoints that can be taken advantage of. I think those would also be dollars that flow from the marketplace to customers in the footprint. I hope that helps.

CHAIRMAIN SCHRIBER: Just a couple quick questions. As Commissioner Roberto said, getting down in the weeds is probably not going to help us a lot right now. But I did tend to complicate Paul's question earlier, and I didn't quite get the answer until just now in PJM's response.

Todd, how do you accommodate within your resource adequacy processes within demand response

MR. RAMEY: I certainly wouldn't want anyone to leave here today with the assumption that demand response cannot participate and qualify as capacity resource under the Midwest ISO, or that the demand response today cannot participate in our ancillary service markets. In fact, in our most recent registration of our Module E resource capacity construct, we had over 8,000 megawatts of registered demand response qualify to participate as qualified capacity in that program.

So to the extent that demand response qualifies as a supply resource, it directly offsets an opportunity cost of either an ownership or contract versus to-supply option, so the opportunity cost for demand response equates to equivalent value of either of those two traditional supply-side options.

In terms of our energy market participation, with the launch of our ancillary service markets in January of this year we also greatly enhance the ability of demand response to participate through competitive offers directly into our day-ahead and realtime markets. Price-responsive demand at the wholesale market can be bid into

Midwest ISO's market. Those are cleared and dispatched and deployed comparably with traditional supply-side resources. So to the extent there are mechanisms allowed for participation of demand response at PJM, we also have similar mechanisms at MISO.

CHAIRMAIN SCHRIBER: Thank you. One more question. I've been spending a lot of years wallowing in the economic swamps. If I could for a moment suggest the study with the 91 million or 26 million, my natural cynicism kind of says let's just set that aside and pretend it's a wash.

And given lots of explanations, Stan, as to why you believe the switch is there, one more question with respect to that. You argue it is better for retail choice. We had a pretty successful outcome not too long ago with respect to retail choice. I'm just sort of curious as to why it would be preferable, or at least you would see some benefit to PJM, in PJM with respect to that.

MR. SZWED: I think the one thing -- I won't go through this whole argument again. But I think the notion of how the capacity is set and the ability to know for certain, that suppliers know what capacity value is. They can take that into their consideration in their pricing and know that ahead of time. I think that's good.

I also think -- maybe Andy can help me on this, too. But I think mechanically in a number of respects, I mentioned the one thing about customer switching, I think PJM has a pretty good program to be able to administer switching of customers, you know, from one supplier to another, and the ability to make sure that they pay for, like in case of capacity, the capacity value that should go along with that switch. I know that's a benefit. I think there probably are some other things that just help in the mechanics of that taking place.

So I look to those and probably other examples of that that would just make it administratively from our standpoint easier. Not to say that MISO's process is bad or I'm criticizing it or anything; I really wouldn't do that. It's really about trying to make it simpler for us.

CHAIRMAIN SCHRIBER: Andy, did you want to add there?

MR. OTT: A little bit. I think you saw the recent FERC report come out the other day about the high volume of the demand response we are seeing, for instance, at PJM and again the volume of competitive load switching that we have. By necessity, since we have such a large percentage of our load that is in the competitive retail space, you tend to have -- we had to create systems that make that switching more efficient and lower the overhead.

For instance, when we did this in New Jersey, when they first put in their competitive auction, one of the first we experienced, they were concerned about transaction overhead, because when load switches, you have to deal the credit issues between the provider of last resort and the new supplier. You have to deal with issues related to load responsibility and various connotations meeting energy responsibilities and reserve sys capacity, transmission service.

So just working out all those contract details, New Jersey had found that once we put in our system to allow daily load switching and absorb all of that complexity into the RTO settlement process on behalf of the all of our customers, our members, New Jersey was estimating they were seeing transaction reductions on a dollar a megawatt hour because it just lowered the transaction fee, the frustration with which to get through this.

Again, I don't know what -- I can only

tell you what exists within PJM. So that type of high volume sort of "business as usual" load switching does, in fact, promote new competitors to come in. And potentially in your auction some of the folks who are participating in New Jersey that may not have come into your auction, in this case they may because it would be a lower barrier for them since they wouldn't have to learn another system, for instance

So that type of thing is what is being referred to here. I don't think by any stretch of the imagination I'm not trying to say we are the only RTO that supports lowering transaction fees. It's just a fact that there is just more volume of it in PJM than there is elsewhere because we had to live through it. That's probably it.

CHAIRMAIN SCHRIBER: Did you want to respond?

MR. RAMEY: I completely agree with Andy's comments in regard to the volume and level of competitive load switching in PJM certainly is greater than what we experienced in Midwest ISO. I would acknowledge this is an area where MISO lags in its evolution of developing these kinds of load-switching capabilities for retail load areas, but we're not sitting still. We have made some progression.

There really are two areas of credits that are important to loads as they switch retail suppliers. The first is ARR credits so the loads have a right to a distribution of the congestion value of the transmission system. That piece of the transfer we already have in place at MISO. To the extent that loads are transferred we accommodate the transfer of those ARR credits to the new LEC that acquires the load and away from the former LEC. So we have been making progress and are implementing those kind of credit switches.

On the capacity side MISO is working to develop the ability to transfer capacity credits in retail load service areas so those credits also have the capability to transfer with loads. That functionality is not currently in place, but it is being developed, and we are working with our stakeholders in that process, and we anticipate that capacity credit transfer capability would be in place in MISO prior to the time that FirstEnergy plans to transfer to PJM.

So we working on that and trying to make progress, trying to work to accommodate and understand the needs of the various business models of the customers in the Midwest ISO, both for vertically integrated structures and companies that participate in retail choice states.

There are unique and different needs of those kind of customers. MISO has worked hard to develop market rules, business practices that serve both business models well. We think that is probably a never-ending endeavor, so we continue to work and make sure we understand the needs of all our customers and do what we can to provide value and accommodate the needs.

CHAIRMAIN SCHRIBER: Thank you. Going down the line.

COMMISSIONER LEMMIE: I just have two additional questions. Todd, the first one is what is the impact that you anticipate on the proposed RTO switch? I'd like to know footprint-wide what the impact might be as well as an in Ohio. I'm concerned about three particular areas: resource adequacy, energy prices, and capacity costs.

MR. RAMEY: I'll try and touch each of those three points, but I want to start with the fundamental realtime day-to-day focus of both RTOs. Let's make sure they're operating these combined generation transmission systems in a manner that provides for reliability moment to moment, day to day and even the planning horizon.

MISO and PJM both do that very well internally. We have been required through the nature of our seam to develop processes through our JOA that helps us administer and manage jointly those seams to maintain the reliability. There are also some equity concerns and issues around the fair allocation of who is providing the services and bearing the costs of providing that joint congestion management.

So in that regard the effectiveness of the JOA, our relationship and operations in working with PJM, I wouldn't anticipate any noticeable change in reliability or operational efficiency of the transition to PJM.

Resource adequacy, again, I think both markets have different but effective constructs in place that will reasonably provide for reliable supply into the planning horizon time frame so I wouldn't anticipate a significant impact on resource supply adequacy going forward either.

Energy prices, I tend to agree with Andy. I would agree with the comment that average energy prices in PJM are higher than average energy prices in the MidweastISO. That's probably a factual statement, but customers don't pay average prices. They pay local prices.

Efficiencies around JOA, again we can direct prices together at the border. Our market participant-initiated economy energy transfers between the two markets works reasonably well to drive those prices together, so I wouldn't anticipate a significant change in energy prices for FirstEnergy with the transition to PJM.

Capacity costs. Capacity costs, like energy, to some degree are locational in nature. Andy mentioned earlier that capacity costs in the eastern part of the footprint are significantly higher than capacity costs in the western part of their footprint. That's true across the combined region as well. There are different locational values of capacity, again, deliverability requirement constraints, transmission capability for new generation.

So I would expect to see a continuation of the variation of capacity costs across the combined footprint. Would I anticipate a marginally different outcome in capacity costs with FirstEnergy transferring to PJM? I don't have any reason to believe that would be the case.

COMMISSIONER LEMMIE: And then lastly, I'd like to ask Andy about the participation duration requirements for a transmission provider's membership in PJM and if, yes, where is that information identified? Is it in a FERC filing? Is it an operating agreement?

MR. OTT: You mean once they're in, do they have to stay for certain amount of time? Again I'm not an attorney, but I'll give you my best answer. I don't believe we have specific time limitations. We also don't have the types of exit fee type of the scenarios just because of the way PJM had evolved because we started from a power pool and moved forward. There wasn't a big start-up cost, lump sum sort of start-up cost at PJM. I don't believe there are specific limitations written down.

Now, obviously as you may have observed in some of the Dusquesne proceedings, because of forward market commitments, for instance, RPM or others, transmission rights, once you're in, there's certain implications, or course, to getting out. You have to take care of your commercial obligations, but there is no administrative obligation on that.

COMMISSIONER LEMMIE: Thank you.

CHAIRMAIN SCHRIBER: Paul.

COMMISSIONER CENTOLELLA: I want to follow up a little bit on this question of people moving because I think there is some concern about there's uncertainty anytime we have a change of this nature, and that uncertainty has some potential costs associated with it.

Andy, first of all, in terms of the next procurement for the POLR auction here in Ohio and with respect specifically to FTR and ARR rights, what would people know and when would they know it under the proposed transition that is going forward with respect to what FTRs and ARRs might be available to serve the market for the next POLR auction proposed for 2010-2011.

MR. OTT: Right. I think what is key, again, is perception of risk for a competitive supplier. When they see something that's unknown, to some extent there's the unknown adder, the risk adder that gets in, and it would tend to be higher than one would anticipate just because they have to essentially hedge their potential maximum downside.

So from that perspective we have discussed with FirstEnergy, look, the best approach here is to have maximum certainty approaching the retail auction. So we would, in fact, want to do transmission right allocations so that people would know definitively these are the transmission rights available not only to the ATSI zone but to other zones in PJM so folks will know going in, here's essentially the state of affairs.

We can do two different flavors of those. Of course, you can do the sample one that says on a forward basis here's what's coming. In other words, do a power flow study and here's what you can reasonably anticipate seeing. We can do one potentially for this year or next year and just say here's what you would have seen had it happened here. Then we can do the ones that are binding that could provide even more certainty.

So I think that issue we can certainly address because the transmission right allocation process is something we tend to do on a forward basis, so I think from that perspective, we would at least encourage FirstEnergy to get that done earlier rather than later.

COMMISSIONER CENTOLELLA: So when would you do the binding allocation with respect to the post-2011 period?

MR. OTT: The binding allocation, I don't have the integration thing in front of me, but starting from June 1, 2011 the binding allocation would normally be done in the February time frame.

COMMISSIONER CENTOLELLA: February 2011.

MR. OTT: Yes, February/March time frame.

COMMISSIONER CENTOLELLA: So that going into this auction that might occur in early 2010, people would not know that.

MR. OTT: Wouldn't have the binding one done. We could certainly do an analysis that would show, here's what a binding one would look like. Again, if you look at the FTR allocation year over year, they tend to be fairly similar. In other words, it's not like a market result where people are offering in. This is just a straight power flow study saying these are the resources to serve the load. Unless you have a major change in transmission, they tend to be relatively static. But if you never had one done before, having a sample one or a set of them done under various scenarios would be extremely beneficial because it would help suppliers understand it.

As far as valuing it, of course, you look at historic prices from MISO and supply those FTRs, assuming they would be similar price profiles. You could also do simulations of forward price separations.

COMMISSIONER CENTOLELLA: Let me turn to a slightly different topic. Mr. Szwed, you made your filing at FERC under Section 205 of the Federal Power Act, which is the section under which FERC determines just and reasonable rates and rates that are not unduly discriminatory, as opposed to under Section 203 of the Federal Power Act, which deals with the disposition of facilities.

Is it your position that it's Section 205 which is the appropriate basis on which FERC has to make that decision?

MR. SZWED: First of all, let me qualify I'm not a lawyer. I'm an engineer, so I'm not sure.

COMMISSIONER CENTOLELLA: I thought you were a FERC compliance officer.

MR. SZWED: I am, but on this particular case our lawyers, our attorneys made the appropriate call under which section to file under, and I believe that's probably how it is done.

MR. BEITING: Would you like us to respond?

COMMISSIONER CENTOLELLA: Sure. That

would be fine.

MR. BEITING: My name is Mike Beiting, associate general counsel for FirstEnergy.

Your Honor, as you're probably aware a number of years ago our companies were involved in some litigation with PJM in Atlantic City, an electric litigation. In that case the Court of Appeals determined Section 203 was not an appropriate vehicle for a situation where a company was transferring operational control over its transmission facilities and that 205, which governed the terms and conditions, not only of rates but contracts, was the appropriate statutory vehicle to be followed in this situation.

COMMISSIONER CENTOLELLA: Now, in the Atlantic City decision, the Court, as I understand it, essentially pointed to Section 202 on the -- the first Atlantic City decision pointed to Section 202, which talks about voluntary coordination, and then in the second Atlantic City decision said that FERC did not have jurisdiction under 203 to compel or even review whether to compel RTO membership. Is that your view?

MR. BEITING: Yes. And I think in light of that decision, this concept that RTO participation and decisions to change from one RTO to another or to join an RTO were voluntary and were governed by the terms of conditions of Section 205.

COMMISSIONER CENTOLELLA: So in your view so long as you meet the requirements under your MISO obligations to leave, your preexisting contractual obligations there, and the RTO that you are joining has just and reasonable rates consistent with Order 888, 890, that is all FERC has the authority to look at.

MR. BEITING: That is correct, Your Honor; absent some kind of merger condition or other overriding grandfathered agreement or something of that nature out there, yes.

COMMISSIONER CENTOLELLA: So then FERC would not in your view have the ability to look at whether it was reasonable to switch from one RTO to another RTO, assuming both have just and reasonable rates and met FERC requirements.

MR. BEITING: Well, I think you have to step back and look at the fact that FERC approved both of these RTOs. They approved them under criteria that is essentially the same. They have approved their tariffs, for example, within the confines of the pro forma open access transmission tariff, and the Commission itself, the FERC, has found that their arrangements are comparable, that they provide customers with fair, just and reasonable service.

And, of course, moving from one RTO to the other, you cannot simply pick and choose which provisions of the tariffs or their agreements that you will adopt. There may be certain narrow exceptions to that, but generally speaking, you go in and you're going to go from one set of just and reasonable agreements to another set of just and reasonable agreements.

COMMISSIONER CENTOLELLA: And so long as you're doing that, your view is that FERC can't ask whether that choice was a reasonable choice or not; is that you're view?

MR. BEITING: I think FERC is certainly going to be presented in this case with questions as to what -- how far does the MISO transmission owner agreements go in terms of those contractual provisions that apply to our transmission customers within the MISO footprint and what those provisions mean, what is necessary to comply with the MISO contracts.

At some point, not in this specific

filing, they will be asked to rule on things like exit fees and integration costs and transmission rates. But in this case I believe that there won't be issues raised as to what the proper interpretation of those agreements are.

I don't think it's simply -- we feel that we met all of the requirements of the MISO TOA agreement. We feel that we're meeting or have committed to meet all the requirements of the MISO tariff that govern a departing transmission owner. But other parties may have different interpretations of that. Now, ultimately, FERC is going to rule on that interpretation, which interpretation is correct.

COMMISSIONER CENTOLELLA: Well, I'm not sure I heard an answer to my question in that. What I'm hearing you say is that so long as whatever FERC says you have to do under the MISO transmission owners agreement you do that, and you comply with whatever FERC says under the terms and conditions of your entry to PJM, that FERC really -- I'm not hearing you say FERC has an ability to look at your -- the reasonableness of your management decision to move from one to the other.

MR. BEITING: What I'm suggesting is this isn't a mechanical process. There's a lot of individual things that FERC is going to have to look at and determine whether the new agreements meet only applicable standards, not only of the RTO we are withdrawing from but the one that we are joining. I think it is a far more sophisticated and detailed process than you're suggesting.

COMMISSIONER CENTOLELLA: Well, I don't want to suggest FERC will not be sophisticated and detailed in its look at it. I guess, are you suggesting that at least insofar as federal regulation is concerned, that it is entirely the FirstEnergy company's choice, assuming they meet all the required terms and conditions, to be in one RTO versus the other?

MR. BEITING: I think ultimately it is subject to that federal regulation. The question as to whether some of the costs we talked about today will be recoverable at a retail level are questions that will be handled in other dockets. They will be handled when you are asked to look at future state rate plans for the Ohio utilities. They will be handled in future rate cases at the federal level.

COMMISSIONER CENTOLELLA: So do I hear you saying you would not take a position that said if this Commission decided to disallow, for example, certain exit costs, if we were to determine that the exit from MISO was not prudent, that you would not contest that that was somehow preempted by federal jurisdiction?

MR. BEITING: well, I think, as Mr. Szwed has pointed out, the payment of the exit fee by ATSI and the recovery of that, the recovery of it will be the subject of a separate future FERC proceeding, and FERC will rule on whether or not that exit fee is recoverable as part of ATSI transmission rate.

COMMISSIONER CENTOLELLA: So you are saying there would be, in your view, federal preemption of that question, you know, in terms of it being a FERC-filed rate?

MR. BEITING: On the particular issue if FERC decides that the exit fee is properly recoverable as part of a FERC-approved transmission rate, then yes, we do think that's a preemption issue.

COMMISSIONER CENTOLELLA: So in terms of where we go from here as in terms of a state proceeding, I guess I am a little, I guess, amazed, for lack of a better word, that you have not come to this Commission and asked this Commission for its approval to make the transfer. And, in particular, given two significant changes that happened in Senate Bill 3 were directly aimed, it appears, at ATSI, both in 4928.12, where the legislature departed from its normal way of looking at this and said not any public utility, but any entity which owns or operates transmission facilities has to be part of a qualified transmission entity, which would basically be an RTO or ISO, and placed that within the Commission's statutory framework; and then in 4905.03 in its definition of public utilities, it specifically carved out an electric light company that provides transmission service for energy that's ultimately deliverable to Ohio consumers, specifically including ATSI, it would seem, under the supervisory jurisdiction of this Commission, why did you not then come to this Commission and request our approval to do this transfer?

MR. BEITING: Your Honor, all I can tell you is that we have looked very carefully at the Ohio statutes, and we see no statute that gives the Commission specific authority to review a move by a utility from one RTO to the other or to set forth any criteria by which that transaction would be decided and resolved.

COMMISSIONER CENTOLELLA: In your view -- is it your view that the move from one RTO to another is not a utility practice that is subject to our review?

MR. BEITING: Well, your Honor, we can certainly address that, if you would like, in our written comments in this proceeding. We have had discussions about this issue before. We have asked your staff as to what provisions they rely upon. We have not gotten an answer to that. If you have specific provisions of Ohio law that you think we should address that we have not, we would be happy to do so.

COMMISSIONER CENTOLELLA: I would be very interested in you, and having other parties, address whether or not, A, this qualifies as a reasonable practice; B, whether or not you had an obligation to come to this Commission under 4905.48 for a contract, again, relating to the transmission owners agreement that AEP and DP&L, as a contract for the joint operation of facilities; also whether or not that you had an obligation under 4905.31, given that the transmission owners agreement includes other financial arrangements as to whether or not you should have brought this here under that agreement.

And finally, under Chapter 4909, given that you're talking about a change in practice which certainly will affect the rates and terms that ultimately are charged to Ohio consumers, whether or not you should have brought this matter affirmatively to the Commission's attention.

MR. BEITING: We will be happy to address those issues that you have raised in our comments. I'm not prepared to respond to them off the top of my ahead today.

COMMISSIONER CENTOLELLA: I would invite if there are other parties who are prepared to respond, I will be happy to hear that now or otherwise invite it in written comments as well.

MR. SMALL: I will address the range of questions that you're asking. I will say that there is a precedent. You heard in my prepared remarks that I suggested that the PUCO should ask FERC to state explicitly that they're not making a finding of prudence and that FERC is not determining that fees are recoverable in rates, and I got that from the Dusquesne order approving the Dusquesne settlement.

So you heard a response from FirstEnergy that they would be recoverable and there would be federal preemption. I'm suggesting in the Dusquesne case, the Pennsylvania Commission challenged that at FERC, received that kind of language in the order, that there would not be federal preemption. That would leave the Ohio Commission the option to look at that at a later date if FERC put those same words into its determination of the FirstEnergy case.

MR. KURTZ: I would just say that I believe that the prudence of the decision of the utility, three utilities that you directly regulate their rates, the prudence of that decision to go to PJM extends beyond simply the exit fees that are associated with it, but potentially to the results of the auction, of the next auction to the extent there are costs that you deem to be unreasonable as a result of that, and the recoverability of those additional costs are in question by the three operating companies.

Now, that statement depends on the outcome of a number of factual determinations that the utilities have not presented you to. They have not presented a study showing the effect on consumers in northern Ohio of the move to PJM. FERC apparently doesn't care. It's nowhere in the application. The 91 million, the 26 million is a potential benefit to the MISO/PJM entire footprint, Michigan to New

Jersey. There's nothing saying what the effect on Ohio consumers will be.

COMMISSIONER CENTOLELLA: Let me just follow up on a couple areas with you, just follow up with one area. In your prepared remarks you mentioned Pike County, which has to do with purchase from one supplier as opposed to another.

Do you believe that this Commission has jurisdiction to speak to the transfer to the extent it would require the load-serving entities to purchase forward capacity and energy as well in one market versus another under the Pike County exception, and could we rule with respect to the prudence of that.

MR. KURTZ: I think that Pike County exception, the prudence of choice exception, goes to recovery of the FERC approved costs and retail rates, I don't know that it goes to the initial decision, but it certainly goes to the fruits, if you will, the outcome of the decision and whether or not the decision was prudent. But I don't know that it goes to the initial decision.

Your strongest jurisdiction, I believe, is the recovery of costs. That's where the Commission's jurisdiction is strongest and clearest, and again, we're not hoping for an outcome where this thing moves forward and then we're in a big battle over what costs are prudent and what costs are not.

We are hopeful that the Commission will be able to use the authority, all the statutes that you cited, plus the prudence of choice exception, Pike County, to negotiate reasonable conditions and a reasonable time frame that is not on this fast track to allow this to move forward more orderly.

COMMISSIONER CENTOLELLA: Mr. Chairman, may I ask one more question?

CHAIRMAIN SCHRIBER: If you must.

COMMISSIONER CENTOLELLA: If we are unable to negotiate the kind of arrangement that you suggest, Mr. Kurtz -- and I will ask other parties if they want to comment -- and we decide we need to have a hearing to resolve the factual questions that have come up in this morning's discussion, what sort of time frame would you need to prepare for that kind of hearing?

MR. KURTZ: I don't know, but -- I don't know. I think it's incumbent upon the utilities who have the burden of proof on the prudence question to come forward with their case.

CHAIRMAIN SCHRIBER: Let me point out

there is no proposal here immediately to have a hearing.

MR. KURTZ: The utilities have the burden of proof. I think an independent expert hired by the Commission, like you did to supervise the auction, would be appropriate. If the answer is there's no effect on consumers, really that the capacity costs of one versus the other are the same, then that would be good news, and if the energy costs are the same, that would be good news. We wouldn't really have any concern. But if the answer is PJM costs are likely to be more, that's when it becomes a problem.

COMMISSIONER CENTOLELLA: Anyone else want to respond to my last question?

MR. SMALL: I will make a comment that for such a proceeding, the OCC would take serious consideration to looking for an outside expert, which would take a little bit of time, talking about a couple months.

COMMISSIONER CENTOLELLA: All right.

CHAIRMAIN SCHRIBER: Commissioner Roberto.

COMMISSIONER ROBERTO: No more questions, Mr. Chair.

CHAIRMAIN SCHRIBER: Any closing remarks?

Everybody is looking at their watches.

Craig, go ahead.

MR. BAKER: The only point that I think is going to be a lot more contentious than we may have talked about today is the issue about the allocation of transmission costs going forward. I don't know how it's going to play out, but I do expect that will be a pretty hotly debated topic at the FERC.

I would note that I understand FE's position on equity on far as when facilities were approved, but then there is the question about when the facilities either go in service or when they are providing service. Many of the assets that are already approved will not be in service before the June of '11 date.

And further, that is an area where I believe there will be contentiousness around the tariff filing and whether that can be -- I hate to open this can of worms -- whether it is a 205 or 206 filing is the appropriate way to change allocation, because that clearly is not the allocation model that PJM has or was dealt with in the Dusquesne case.

So I wanted to just bring it to the Commission's attention that that is an area that I think we will have a lot of debate over.

CHAIRMAIN SCHRIBER: Thank you very much, and we would welcome -- there's been some discussion about competitive suppliers. There would be some interest in getting comments from you all, and again, I didn't mean to step on any toes, but there is no immediate plan for a hearing. We are going to move forward and go with the flow and see how things go here.

So with that, I thank you all for your participation. We will recess the Commission meeting until 1:30. Thanks you all.

(The meeting adjourned at 11:46 a.m.)

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CERTIFICATE

I do hereby certify that the foregoing is a true and correct transcript of the proceedings taken by me in this matter on Tuesday, September 15, 2009, and carefully compared with my original stenographic notes.

_s/Rosemary Foster Anderson_________
Rosemary Foster Anderson,
Professional Reporter and
Notary Public in and for
the State of Ohio.

My commission expires April 5, 2009.

(RFA-8335)

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