ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION INTO ANY AND ALL MATTERS RELATED TO COMMISSION APPROVAL OF PARTICIPATION BY INDIANA END-USE CUSTOMERS IN DEMAND RESPONSE PROGRAMS OFFERED BY THE MIDWEST ISO AND PJM INTER-CONNECTION	)	**CAUSE NO. 43566**
	)	**APPROVED:** JUL 28 2010
RESPONDENTS: INDIANA REGULATED ELECTRIC UTILITIES	)	

<u>BY THE COMMISSION</u>:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Administrative Law Judge

On September 3, 2008, the Indiana Utility Regulatory Commission ("Commission") initiated an investigation into any and all matters relating to participation by Indiana end-use customers in demand response programs offered by the Midwest Independent Transmission System Operator, Inc. ("MISO" or "Midwest ISO") and PJM Interconnection, LLC ("PJM").

All Indiana Regulated Electric Utilities ("Respondent Utilities") were named Respondents in this Cause. Appearances were filed for the following utilities: Anderson Municipal Light & Power ("Anderson"), City of Auburn, Indiana ("Auburn"), Crawfordsville Electric Light & Power ("Crawfordsville"), City of Logansport ("Logansport"), Mishawaka Utilities ("Mishawaka"), Richmond Power & Light ("Richmond") and City of Tipton ("Tipton") (collectively referred to herein as "Municipal Utilities"); Indiana Michigan Power Company ("I&M"); Duke Energy Indiana, Inc. ("Duke"), Indianapolis Power & Light Company ("IPL"), Northern Indiana Public Service Company ("NIPSCO"), and Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren") (collectively referred to herein as "MISO Utilities"); Northeastern Rural Electric Membership Corporation ("NREMC"); Marshall County Rural Electric Membership Corporation ("Marshall"); Harrison County Rural Electric Membership Corporation ("Harrison REMC"); and Jackson County Rural Electric Membership Corporation ("Jackson"). The Indiana Office of Utility Consumer Counselor ("OUCC") also appeared and participated in this Cause.

The Presiding Officers granted Petitions to Intervene filed by: Steel Dynamics, Inc. ("SDI"), Indiana Industrial Group ("Industrial Group"), Indiana Statewide Association of Rural Electric Cooperatives, Inc. ("Indiana Statewide"), Wabash Valley Power Association, Inc. ("WVPA"), CPower, Inc. ("CPower"), Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier Energy"), MISO, PJM, Indiana Municipal Power Agency ("IMPA"), LaPorte County Board of Commissioners ("LaPorte"), Citizens Action Coalition of Indiana, Inc. ("CAC"), Wal-Mart Stores East, LP and Sam's East, LP ("Wal-Mart"), and EnerNOC, Inc. ("EnerNOC").

On October 8, 2008, the Commission issued a Prehearing Conference Order which, among other things, established a procedural schedule for this Cause. To assist in defining the issues to be addressed, Technical Conferences were held on October 20, 2008, December 12, 2008 and January 26, 2008.

On January 23, 2009, the Industrial Group filed a Motion for Issuance of Interim Order authorizing qualified entities to register for and participate in PJM's demand response programs for the summer of 2009. On February 2, 2009, I&M, Municipal Utilities and IMPA filed a Verified Joint Motion for Expedited Issuance of Order Maintaining Status Quo and Expressly Barring End-Use Customer Participation in RTO Demand Response Programs. Responses and Replies to both Motions were filed by various Respondents, Intervenors and the OUCC. On February 25, 2009, the Commission issued an Order on Requests for Interim Relief prohibiting Indiana end-use customer participation in Regional Transmission Organization ("RTO") demand response programs until further order of the Commission, unless such end-use customer has or receives an order from the Commission authorizing such participation.

In accordance with the procedural schedule and the Presiding Officers' February 2, 2009 Docket Entry, the parties prefiled initial testimony on March 5, 2009 and responsive testimony on April 6, 2009.[1]

Pursuant to notice, duly published as required by law, an evidentiary hearing was held on April 21, 2009 at 9:30 a.m. in Room 222 of the National City Center, 101 W. Washington Street, Indianapolis, Indiana. At the hearing, the testimony and exhibits of the parties were offered and admitted into the record without objection. No other members of the public appeared.

The Commission, having examined the evidence and being duly advised in the premises, now finds that:

1. <u>Notice and Jurisdiction.</u> Due, legal and timely notice of the evidentiary hearing in this Cause was given as required by law. Respondents are operating public utilities, or rate-regulated municipally owned utilities, within the meaning of those terms in Ind. Code § 8-1-2-1(a) and (h) of the Public Service Commission Act, as amended, and are subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. The Commission has broad authority pursuant to Ind. Code § 8-1-2-58 and 59 to investigate matters relating to public utilities. Therefore, the Commission has jurisdiction over Respondents and the subject matter of this Cause.

2. <u>Purpose of Investigation.</u> In Cause No. 43426, the MISO Utilities sought, among other things, Commission approval of certain operational changes necessary to permit the MISO Utilities to participate in the Midwest ISO's Ancillary Services Market ("ASM"). The Industrial Group, an intervenor in that case, asserted that demand response resources must be available to the Midwest ISO to achieve the intended goals of ASM. Consequently, the Industrial Group advocated that Commission approval of MISO Utilities' participation in the ASM be conditioned upon the MISO Utilities' individual tariffs providing the opportunity for

[1] PJM filed its responsive testimony on April 13, 2009 in accordance with the Presiding Officers' April 9, 2009 Docket Entry.

their respective retail customers to participate in the Midwest ISO's demand response programs. Although the Commission denied the Industrial Group's proposal to require MISO Utilities to modify their respective tariffs, we found that:

> … demand response resources and measures are becoming increasingly prevalent, [and that the Commission] should further evaluate possible procedures for considering and, if appropriate, streamlining requests by end-use customers seeking to participate in the various demand response programs offered by RTOs in Indiana. Therefore, we find that the Commission should commence an investigation within thirty (30) days of this Order to examine any and all issues associated with an end-use customer's participation in demand response programs offered by the Midwest ISO and the PJM Interconnection.

Cause No. 43426, Phase I Order dated August 13, 2008 ("Phase I Order") at 19. Thus, this investigation was commenced to allow the Commission to consider and review any and all matters associated with an Indiana end-use electric customer's participation in demand response programs offered by the Midwest ISO or PJM.

3. Summary of Evidence. Pursuant to the Commission's February 2, 2009 Docket Entry, the parties presented evidence relating to the issues to be considered in this proceeding. The following parties filed Initial/Direct Testimony of the identified witnesses:

MISO Utilities	Timothy R. Caister, Director, Electric Regulatory Policy, NIPSCO; Marlene S. Parsley, Senior Energy Market Analyst, Vectren; Bruce L. Sailers, Manager, Retail Energy Desk, Duke; John E. Haselden, Principal Engineer, IPL; and Jerrold L. Ulrey, Vice President, Regulatory Affairs and Fuels, Vectren.
I&M	David M. Roush, Manager-Regulated Pricing and Analysis, I&M.
Harrison REMC	David C. Lett, General Manager/CEO, Harrison REMC.
NREMC	Gregg L. Kiess, President and CEO, NREMC.
Auburn	Stuart L. Tuttle, Superintendent of the Auburn Electric Department, Auburn.
Hoosier Energy	Mike Mooney, Manager, Corporate Planning, Hoosier Energy.
IMPA	L. Gayle Mayo, Executive Vice President and Chief Operating Officer, IMPA.
WVPA	Gregory E. Wagoner, Vice President, Business Development, WVPA.
OUCC	Andrew J. Satchwell, Utility Analyst, OUCC.
Industrial Group	James R. Dauphinais, Consultant, Brubaker & Associates, Inc.

Wal-Mart	Kenneth E. Baker, Senior Manager for Sustainable Regulation of Wal-Mart Stores, Inc.
PJM	Paul M. Sotkiewicz, Ph.D., Senior Economist in the Market Services Division of PJM.[2]
CPower	Thomas Rutigliano, Program Manager, Mid-Atlantic Region, CPower.

In lieu of filing Initial/Direct Testimony, MISO filed a Position Statement responding to Issues No. 4, 12 and 13 only.

The following parties filed Reply/Responsive Testimony of the identified witnesses:

MISO Utilities	Timothy R. Caister; Bruce L. Sailers; John E. Haselden; and Jerrold L. Ulrey.
I&M	David M. Roush.
OUCC	Andrew J. Satchwell.
Industrial Group	James R. Dauphinais.
Wal-Mart	Kenneth E. Baker.
PJM	Peter L. Langbein, Manager – Demand Side Response Operations in the Market Services Division of PJM.
CPower	Thomas Rutigliano.

In lieu of filing Reply Testimony, EnerNOC filed a Position Statement supporting Wal-Mart's reply testimony.

A. The Parties' Direct Evidence.

1. MISO Utilities. Timothy R. Caister provided an overview of demand response in the Midwest ISO. Mr. Caister explained demand response as the ability to motivate changes in a customer's electricity usage in response to changes in price intended to encourage lower electricity use. He stated that the Midwest ISO is continuing to draft and finalize rules and business practices for its demand response tariffs. Currently, the Midwest ISO Tariff includes opportunities for Type I and Type II Demand Response Resources and Emergency Demand Response.

Mr. Caister pointed out the significant differences between the Midwest ISO and PJM impacting demand response, including: most states in PJM are deregulated, PJM's demand

[2] On April 13, 2009, PJM filed its Notice of Witness Substitution. Peter L. Langbein adopted Dr. Sotkiewicz's prefiled direct testimony as his own.

response programs are more developed, and PJM has a greater role in resource planning. For these reasons, Mr. Caister stated that direct participation may be more feasible in PJM than in the Midwest ISO. He testified that the Midwest ISO Tariff incorporates the ability of the MISO Utilities to participate in demand response programs on behalf of its customers, which allows the utility to monitor the impact of the demand reductions and adjust for its impact on the utility's load and capacity. Mr. Caister therefore suggests that allowing direct participation would result in a risk that the MISO Utilities would experience significant imbalances and shifts in costs between customers and customer groups.

Mr. Caister described how NIPSCO's existing demand response programs work for NIPSCO. He stated that such programs are generally price-based or incentive-based and provide the opportunity to treat load reductions as a supply alternative. Mr. Caister testified that these programs benefit all stakeholders by minimizing costs, reducing or delaying the need for new capacity, provide direct benefits to specific customers and work in conjunction with demand side management ("DSM").

Mr. Caister explained the MISO Utilities' concern that direct customer participation in Midwest ISO demand response programs would undermine an Integrated Resource Plan ("IRP") by introducing new risks as to how much load utilities must plan for, and impacts on settlement processes. Mr. Caister conceded such issues are not insurmountable, but argued that the MISO Utilities are the most appropriate entities to facilitate demand response programs for Indiana customers. Mr. Caister suggests that the Midwest ISO, the MISO Utilities, and Indiana customers work together to develop new or modified riders and/or tariffs for Commission approval to remove the necessity for individual customer applications that may now be viewed as a barrier to entry.

He testified the benefits of participation through the utility include more accurate and efficient resource planning, the assignment of responsibility for any charges to ensure that non-participating customers are not harmed, and the opportunity for "a full discussion" with the customer of all demand response opportunities (*i.e.*, those offered by the utility and the Midwest ISO). He testified further that non-participating customers would also realize benefits from such participation in terms of enhanced system reliability, lower resource costs, and environmental benefits. With respect to small and medium sized customers, Mr. Caister suggested that aggregation is best accomplished by the utility because of the regulatory protections such an approach offers, but stated the MISO Utilities were open to considering the indirect participation of third party aggregators through the utilities' market participant status.

Mr. Caister expressed concern about direct participation by customers in light of Indiana's regulatory framework, in terms of interfering with the utility's obligation to plan and serve under the traditional regulatory bargain. Mr. Caister suggests that allowing direct participation would interfere with this balance, which might result in various kinds of confusion. Finally, Mr. Caister raised concerns about ensuring that appropriate notice is provided as to end-use customer participation in Midwest ISO demand response programs, and suggests that such issues – and the availability of information to the Commission – could be best addressed by having all such participation take place through the utility.

Mr. Caister concluded his direct testimony with a description of NIPSCO's demand response-related activity. Mr. Caister briefly summarized NIPSCO's current offerings, including tariff-based demand response, special contracts and the pending DSM programs in Cause No. 43618. Mr. Caister also testified that NIPSCO is working with large industrial customers on a program for Commission approval to allow a reasonable demand response offering through the utility into the Midwest ISO market, and that NIPSCO regards such activity as a "prime opportunity" to work collaboratively with its large customers in order to achieve benefits for all stakeholders. Finally, Mr. Caister noted that NIPSCO does register an amount by month of interruptible capacity with the Midwest ISO as demand response, which is used by NIPSCO to satisfy its Module E resource adequacy obligations under the Midwest ISO tariff.

Marlene S. Parsley addressed the technical aspects relating to direct access by customers to the Midwest ISO demand response markets. Ms. Parsley testified that the MISO Utilities look to their demand response programs to provide increased reliability and a reduction in the capacity required to meet resource adequacy requirements. She expressed concern that removing an end-use consumer's participation from their programs will require the submission of higher peak load forecasts to the Midwest ISO or will reduce the amount of resources available to meet that peak. She testified that this would require the MISO Utilities to secure additional capacity, resulting in additional costs to non-participating customers, and that the MISO Utilities would be at an increased risk to incur penalties as the result of load forecast deviations.

Ms. Parsley testified that under the MISO Utilities' existing demand response programs, she could not suggest a way for customers to participate in Midwest ISO demand response programs and obtain a majority of the benefits without shifting costs to other retail ratepayers. However, she indicated that it would be possible to design new or amended utility tariffs, riders or special contracts to allow such customers to receive a "material" amount of such benefits while participating through the local utility. She stated that such tariffs, riders, or special contracts would have to be carefully designed to ensure that other operational parameters, such as metering, response time, and minimum amounts, would meet the requirements of the Midwest ISO markets. She offered an example of how such a process would work.

Bruce L. Sailers described Duke's current and proposed demand response programs, which include incentive-based or time-based rates, and its plans for further demand response program development. Mr. Sailers also described how Duke uses its demand response programs as Midwest ISO Planning Resources, and stated that Duke relies on its demand response resources in its IRP analysis. Finally, he stated that with respect to small customers, Duke believes aggregators should be required to participate in the Midwest ISO only through the utility, and that several of Duke's existing and planned programs will provide some opportunity for smaller customers to participate in demand response offerings.

John E. Haselden provided testimony as to IPL's current demand response riders, including air conditioning load management, interruptible power, load displacement, and two energy curtailment offerings. He stated that IPL also plans to work with its customers on new or revised riders to allow IPL to participate on a customer's behalf in the Midwest ISO's demand response programs. With respect to third party aggregators, Mr. Haselden agreed with Mr. Sailers that their participation should only be through contracts with the utility.

Jerrold L. Ulrey testified concerning Vectren's current demand response and aggregation riders and adjustments, and Vectren's proposal to work with interested stakeholders on new riders or adjustments to allow customers to participate indirectly in the Midwest ISO's demand response programs. Mr. Ulrey described the three categories of Vectren's current programs: tariff-based demand response, special contracts, and demand side management programs. Like the other MISO Utilities, Mr. Ulrey stated that Vectren has plans to work with its customers and other stakeholders to evaluate the need for new or revised services that will facilitate customers' participation in the Midwest ISO's demand response markets.

2. I&M. David M. Roush testified concerning I&M's position on requests by end-use customers to participate in PJM demand response programs. He stated that Federal Energy Regulatory Commission ("FERC") Order 719 requires RTOs to accept bids into ancillary service markets from demand response resources, including end-use customers and aggregators of retail customers, unless not permitted by the laws or regulations of their relevant electric retail regulatory authority. He stated his belief that FERC recognized in Order 719 that states such as Indiana may perceive more downside consequences than upside benefits to retail customer participation in wholesale markets, and therefore provided a mechanism for states to preclude such participation.

Mr. Roush testified as to I&M's belief that direct customer participation in RTO demand response programs does not work effectively in regulated retail jurisdictions such as Indiana because such programs have not been designed to work with embedded cost average rates. Mr. Roush stated that customers taking market-based service in deregulated states are subject to market prices for their supply. However, I&M's retail customer do not pay market prices for their supply; they pay demand and energy rates that are based on I&M's average embedded costs, as well as credits received by I&M for sales in wholesale markets of excess power not used by native load customers. As a result, Mr. Roush argued, customers who directly participate in such PJM demand response programs buy energy from I&M at a charge based on the average embedded cost of energy produced by I&M and then "resell" that energy at market prices by curtailing usage. He stated that such participating customers are able to benefit from the arbitrage between embedded average cost and market, and have no incentive to work with I&M within existing tariffs to manage their load, and that this is done at the expense of other I&M customers.

Mr. Roush testified concerning his understanding that FERC considers retail customer demand response participation in wholesale markets to effectively be two transactions: (1) the retail sale of electricity to the customer by the utility, and (2) the resale of that electricity into the wholesale market. Mr. Roush argued that a customer's participation in PJM's demand response programs would constitute a "reselling" by retail customers, which is prohibited under I&M's tariff.

Mr. Roush described aggregators or curtailment service providers ("CSPs") as third parties seeking to sell the electrical load of a utility customer to an RTO; they essentially serve as brokers of the "resale." According to Mr. Roush, obvious and fundamental distinctions exist when comparing a retail customer's resale of I&M's generation and I&M's sales into the wholesale market using its own generation assets. He stated that there is no comparison between a company using its own assets to support wholesale power sales and a retail customer, buying at regulated tariff rates rather than market rates, entering into a bilateral transaction to resell power in the wholesale market that was supposed to be purchased by the customer for its own consumption – especially since the terms and conditions of the retail tariff prohibit such resale. He testified that the end-use customer and CSP are, in effect, claiming control over the utility's generation to make a sale into the wholesale market.

Mr. Roush testified that I&M offers interruptible services to its customers under Commission-approved tariffs and contracts and offers a number of time-of-day rates. He also mentioned I&M's Smart Metering Pilot in the South Bend area, which includes experimental time-of-day rates for residential and small commercial customers as well as an experimental direct load control rider for residential customers. He stated that such offerings were designed to ensure that the compensation provided to customers who are willing to reduce usage when requested is balanced with the benefit to all Indiana customers of ensuring adequate capacity.

Mr. Roush stated that I&M incurs costs to verify a customer's registration with PJM and in verifying a customer's load before and during each curtailment. He also stated that a participating customer is not required to pay for the utility meter that is necessary for the utility to validate settlement payments made under the program or ensure that all other customers are truly benefiting from the demand response for which they are paying. Under current PJM rules, according to Mr. Roush, all of these costs are absorbed by I&M with no compensation from PJM or the benefiting customer and ultimately passed on to all I&M retail customers.

Mr. Roush also testified that the Commission requires demand response programs be included in each utility's IRP analysis. In particular, an electric utility is to consider alternative methods of meeting future demand for electric service, including demand side resources. For I&M's retail interruptible customers, Mr. Roush testified that I&M incorporates that demand response capability into its portfolio to meet its capacity obligation. By contrast, he stated, a customer directly participating in PJM's demand response programs is of no use to I&M for capacity planning purposes. He stated that I&M must count the load of PJM demand response participants as firm, and the cost of doing so will be reflected in I&M's retail rates – a cost that could be avoided if the customer participated in an I&M demand response program.

In addition, Mr. Roush stated that I&M uses its interruptible customers to manage high costs of energy. However, if a customer directly participates in a PJM demand response program, then I&M is no longer in control of the load response. He stated that I&M lacks sufficient knowledge regarding the load, including when the customer may be planning to discontinue participation in the DR program. Regardless of an end-user's decision to participate in a PJM demand response program, Mr. Roush testified that I&M is obligated and required to serve it and all customers within its retail service area. Consequently, I&M must plan and build or acquire capacity for the total customer load, regardless of an end-user's intent. Over the long term, Mr. Roush argued, this increases the cost for all I&M customers.

Mr. Roush testified that I&M customer participation in PJM programs would reduce the potential market for I&M DSM programs or require I&M to "outbid" PJM programs. In the future, if Indiana adopts demand reduction and/or energy efficiency benchmarks similar to those found in other states, he testified a load reduction due to direct customer participation in a PJM demand response program likely would not count toward state goals since the reduction is for PJM purposes and not necessarily aligned with Indiana peaks or goals.

Mr. Roush reiterated I&M's belief that it is inappropriate for customers of any size to participate in PJM demand response programs. He testified that under PJM's programs, small and some medium sized customers must be aggregated to create a sufficient volume of demand response to participate, which would be unnecessary if customers participated in I&M's programs. While he acknowledged that I&M's current curtailment tariffs are not available to small and medium size customers, he testified such service offerings could be made available.

Additionally, Mr. Roush testified that should Indiana choose to allow a CSP to enroll Indiana end-use customers in PJM's demand response programs, that entity should be required to register with the State of Indiana as a public utility and submit its aggregation plans for approval to the Commission. He stated this would allow the Load Serving Entity ("LSE") the opportunity to review and comment on the aggregation plans and attempt to incorporate those plans, to the extent possible, into its planning efforts. However, he further testified that under an aggregation plan, customers across several jurisdictions, including Indiana, may be responding to PJM curtailments to benefit customers located hundreds of miles from Indiana, with I&M's other Indiana customers left to pick up the costs.

Mr. Roush stated that to the extent the Commission decides to permit retail participation, I&M believes that requiring a retail customer to use its LSE as the agent for participation in PJM's programs makes sense. That approach, he argued, would allow the Commission and the utility to put Indiana's demand response resources to better use. By requiring coordination through the LSE, Mr. Roush testified the utility could have better control over when the demand response is invoked and what compensation is provided in the context of a customer's use of the retail electric service being provided by the utility. In addition, he testified, the participating customer's demand response capabilities could be utilized to meet the LSE's capacity obligation and ultimately reduce cost impacts on all customers.

According to Mr. Roush, there are two major limitations associated with requiring retail participation through the LSE. First, because the PJM programs are designed to address PJM peak demand and are not tied to peak demand within Indiana or to an individual utility's peak demand, the impact on an Indiana utility's resource planning is limited. By contrast, he stated, if an Indiana utility offers its own retail program designed to enhance its own generation resource needs, the impact of such demand response programs is greater and more efficient. In addition, I&M's generation resources provide a benefit to I&M's customers by ensuring adequate capacity is available to meet their usage requirements and to also share in off-system sales that I&M may make from excess generation. When I&M's end-use customers resell power they otherwise would have consumed for their use through participation in PJM demand response programs, I&M's generation resources become less a benefit to I&M's other non-participating customers and more a benefit to individuals located in areas outside of Indiana and outside of the AEP footprint. Second, if the Commission or the legislature imposes demand response mandates under Indiana law in the future, the demand resources through customers participating in the PJM programs might not be available for in-state use if they were tied up in the PJM programs. At a minimum, in-state programs would have to compete for such resources, and the resulting cost to Indiana would be higher.

Mr. Roush concluded by stating that I&M objects to retail customers participating in PJM DR programs when those retail customers are purchasing power from I&M at regulated retail rates. He stated I&M believes that participation in PJM's programs should be limited to LSEs within PJM and should be incorporated into the demand response programs implemented by LSEs. I&M believes that utilities in regulated states, such as Indiana, should participate in RTO demand response programs on a wholesale basis to the benefit of all customers. I&M believes that the Commission and Indiana's utilities should work together to design appropriate demand response programs for retail customers.

3. **Harrison REMC and NREMC.** David C. Lett testified that Harrison REMC is a local distribution cooperative that purchases its electric power and energy pursuant to an all-requirements contract with Hoosier Energy. Gregg L. Kiess testified that NREMC is a local distribution cooperative and an all-requirements purchaser of power from WVPA. Mr. Lett and Mr. Kiess testified that their respective REMC believes retail customers or CSPs operating on behalf of retail customers should be required to obtain Commission approval prior to participation in RTO demand response programs. However, they stated that such participation should be conditioned on: (1) the retail customer being required to receive electric service under a decoupled/unbundled rate to avoid possible economic loss; (2) the retail customer having only one CSP to avoid the potential for double recovery when a retail customer participates in both utility and RTO sponsored demand response programs; and (3) retail customers offering large loads, such as 50 KW or greater, because smaller loads are likely uneconomical.

4. **Auburn.** Stuart L. Tuttle addressed Auburn's concerns with end-use customer participation in RTO demand response programs. He stated his belief that such participation could complicate resource planning. He stated that when a utility implements its own DSM program, it plans for the expected reduction in load. However, if an end-use customer participates in a RTO DSM program, the utility would need to include the full loads of its retail customers in its planning for firm power supply and would need to make arrangements to meet that load in its wholesale power supply contract.

Mr. Tuttle opined there is a potential for direct customer participation in an RTO demand response program to shift costs to other customers. He stated that if a customer directly participates in an RTO program, then the utility may lack sufficient load information for planning purposes and may result in a possible shifting of capacity cost to other customers. He indicated this may be exacerbated for municipal utilities that serve limited industrial customers.

Mr. Tuttle also expressed concern that allowing end-use customers to participate in RTO demand response programs would have a detrimental effect on participation in demand response programs offered by municipal utilities. He explained that Auburn is currently seeking approval of a program wherein qualifying customers may reduce electric costs by shifting consumption to off-peak periods. The goal of this program is to improve the utility's overall system load factor, thereby potentially reducing wholesale power costs. Mr. Tuttle stated customers would likely find the incentives of the RTO demand response programs more attractive, to the detriment of Auburn Electric's proposed program.

Mr. Tuttle concluded by recommending that the Commission make certain it has the input of regulated municipal electric utilities when considering requests of their end-use customers for participation in an RTO demand response program.

5. **Hoosier Energy.** Mike Mooney testified that Hoosier Energy is a generation and transmission cooperative supplying the electric requirements of its members through long-term wholesale power contracts. He stated that while its members are the LSEs, Hoosier Energy represents member interests when dealing with PJM and the Midwest ISO. As the majority of member load was served from the MISO transmission system, he focused his testimony on the MISO market.

Mr. Mooney expressed concern about the effect of end-use customers' participation in RTO demand response programs on long term resource planning. Mr. Mooney noted that most of the demand response benefits to Hoosier Energy are in the form of avoided capacity costs. In order to realize this benefit, Mr. Mooney stated the utility needs to control the demand response resource, or the RTO resource adequacy requirements must account for the end-use customer's demand response resource and credit the LSE for such resource, including the payment of any penalties for lack of compliance. Mr. Mooney stated that the current MISO construct does not provide adequate assurance of the latter.

Mr. Mooney did not object to end-use customer participation in RTO demand response programs, so long as costs are not shifted to other retail customers. However, he opined that under the Midwest ISO's current construct, costs would be inappropriately shifted. Mr. Mooney also stated if the RTO demand response markets are properly structured, non-participating retail customers may realize benefits.

Mr. Mooney further explained that, because distribution cooperatives are not vertically integrated and likely recover a portion of fixed costs through energy sales to retail customers, these companies may incur lost margin resulting from a reduction in energy sales. Mr. Mooney pointed out this may be the case even if the RTO demand response program protects generation and transmission interests. He stated this retail lost margin can be avoided if participating retail customers are required to receive service under a decoupled rate. The decoupled rate allows the cooperative to fully recover fixed costs through the facility charge, rather than the energy charge.

Finally, Mr. Mooney also stated that, due to the sophistication necessary to participate in RTO demand response programs, only industrial and large commercial customers should be allowed to participate subject to taking service under decoupled rates. In addition, he testified that Hoosier Energy supported a requirement that an end-use customer wishing to participate in a RTO demand response program seek Commission approval, which should prevent the potential for a participant having multiple CSPs.

6. **IMPA.** L. Gayle Mayo initially noted that RTO demand response programs at both the Midwest ISO and PJM are still being developed, and that IMPA's primary concern is the potential impact of RTO demand response capacity programs on resource adequacy and long-term planning.

Ms. Mayo testified that, unlike most utilities, IMPA has load in both the Midwest ISO and PJM footprints. IMPA is responsible for its 52 municipal members' long term planning, which has been challenging due to the two different sets of rules in the two RTOs. Consequently, Ms. Mayo expressed concern that allowing direct customer participation in RTO demand response programs would only add another layer of complexity. She stated that IMPA believes that the RTOs' demand response programs will provide the most benefit to all customers if they are fully integrated into the utility's own resource planning process. Ms. Mayo stated that IMPA is committed to assisting its members in the development of demand response resources and is currently in the process of revisiting its wholesale interruptible rate.

Ms. Mayo expressed concern about not being able to include customer demand response in its load forecast. She also suggested that on a local level, allowing direct customer participation may undermine the local utility's attempts to provide demand response offerings. Given the small number of customers in some of IMPA's smaller members, the loss of a small number of customers in favor of the option of direct participation, or the enrollment of customers with a third-party aggregator, might leave no customers left to participate in the member's demand response program.

Ms. Mayo testified that removing RTO demand response customer load for utility planning purposes is not practical. She stated demand response is essentially treated like capacity from a generator; a generator cannot be used without load, so the load cannot simply be removed. Moreover, in order for PJM to pay the retail customer for the demand response, it must charge the LSE for the load.

Ms. Mayo stated that RTO demand response participation should take place through the local utility, and that deregulated municipals could adopt ordinances that require demand response programs to be provided by the local utility. As to potential cost shifting, Ms. Mayo testified that the small size and rate structure of municipal utilities makes them particularly vulnerable to cost shifting issues and therefore it is essential that the demand response participation process involve the local utility. Ms. Mayo also testified concerning the implications of direct participation for non-participating customers, and about the jurisdictional implications of direct participation by either end-use customers or aggregators. Finally, Ms. Mayo expressed concern about ensuring that the jurisdiction of relevant retail regulatory authorities (including municipals) is protected under FERC's Order 719.

7. **WVPA.** Gregory E. Wagoner testified that WVPA is a non-profit generation and transmission cooperative providing wholesale power and transmission service to its 30 members for resale to retail customers. Although WVPA's members are considered LSEs, WVPA normally represents its member systems when dealing with MISO and PJM demand response programs.

Mr. Wagoner described WVPA's load management programs, and its load management objectives to increase load factor by peak clipping, load shifting/valley filling and promoting off-peak usage. He stated these measures are utilized to reduce capacity and energy costs, including during high priced conditions.

Mr. Wagoner also described how WVPA works with PJM and the Midwest ISO. Although Mr. Wagoner indicated that the PJM process holds the utility harmless for long-term planning purposes, he expressed concerns that the Midwest ISO's current demand response programs only work when demand response participates through the utility. Mr. Wagoner further expressed concern about direct participation resulting in shifting of costs to other retail customers. As a result, WVPA recommends that certain additional obligations be required of end use customers in PJM to avoid cost-shifting, and that end-use customers participate in the Midwest ISO only through local utility-sponsored programs because cost-shifting cannot otherwise be avoided.

With respect to non-participating customers, Mr. Wagoner testified that the benefits of demand response programs generally are found in the form of avoided costs. Mr. Wagoner stated that they work very well in PJM, especially now that PJM has eliminated the incentive payments. However, he indicated that there was a potential for distribution cooperatives to incur economic losses not offset by PJM demand response programs that benefit WVPA. He further stated that because the Midwest ISO does not currently offer direct participation, it was impossible to address the cost shifting impacts.

Mr. Wagoner testified that because a certain amount of market sophistication and technical infrastructure is necessary to participate directly in RTO demand response programs, WVPA believes that only industrial and large commercial customers should be allowed to participate. Such participation should be limited to PJM demand response programs and the customer is subject to decoupled rates. Finally, Mr. Wagoner testified that WVPA supports requiring any retail customer or third party aggregator who wants to participate directly, to be required to do so by seeking Commission approval, which would eliminate the potential for double dipping, having multiple CSPs, or cost shifting.

8. OUCC. Andrew J. Satchwell testified that the OUCC recommended the Commission order generic tariffs be offered by the utilities to allow end-use customer participation in RTO demand response programs through the utilities, that CSPs be provided an opportunity to participate through the utility under an agency agreement or contract status, and that the Commission order a three-year trial period to gather information and identify any need for revisions or modifications to the generic tariffs.

By way of providing context for his recommendations, Mr. Satchwell described a set of general principles articulated by the OUCC with respect to demand response participation in RTO markets. First, he stated that such methods for participation should provide fair, non-discriminatory access. Second, such methods should address tariff differences among the utilities. Third, such methods should address long-term planning and resource adequacy issues. Finally, such methods should allow for the voluntary participation of end-use customers.

Mr. Satchwell described the benefits he expected from participation by end-use customers in RTO demand response programs. First, he testified that it would foster the objective of regulatory policy to achieve the efficiencies of competitive markets within Indiana's regulated framework, on the grounds that the "competition of ideas" would help improve products and services. Second, Mr. Satchwell cited the increased integration of retail and wholesale markets, and argued that allowing customers to respond to market signals would greatly enhance the overall efficiency of electric markets, lower peak Locational Market Prices ("LMPs") and mitigate the potential for market power. In addition, Mr. Satchwell argued that RTO demand response would improve fairness and equity, in particular by striking a balance between a utility's ability to reliably serve load and cover its costs, and the ability of customers to better manage their energy costs.

Mr. Satchwell recognized that allowing new forms of participation may raise new issues. In particular, he cited a need for increased transparency in how end-use customers participate in demand response opportunities at the RTO, particularly with respect to short and long-term planning, integrated resource planning and resource adequacy issues. Mr. Satchwell also recommended a fixed trial period of participation, with a view toward applying the experience gained through increased customer demand response participation to develop a better balance than may be possible today, and to address any gaming or other problems which arise. He also recommended that CSPs be allowed to participate only on a trial basis as agents/contractors of the utilities, which would allow the Commission to ensure that reliability and other potential issues are addressed through the utility. Mr. Satchwell noted that CSPs may provide benefits by facilitating the participation by customers which are too small to otherwise participate, and by assuming business risks which may be inappropriate for a regulated utility.

Mr. Satchwell concluded by recommending that the Commission require the development of generic demand response tariffs with the following features: (1) a self-schedule option that allows end-users to notify and schedule on a day-ahead basis, (2) a utility-schedule option that would include an opt-out provision, (3) payments structured to flow the majority of revenues to participating customers, and (4) energy and capacity program options. Mr. Satchwell indicated that such "generic" tariff offerings should be the same for all utilities to avoid discrimination among utilities, but should also respect each utility's terms of service. He stated such generic demand response tariffs would enable faster regulatory response time and reduce the transaction costs for participating customers.

9. Industrial Group. James R. Dauphinais began by explaining his conclusion that the current case-by-case approach for end-use customer participation in RTO demand response programs unduly inhibits participation to the detriment of potential participating customers and non-participating customers of the Respondents. He stated that he recommends the Commission streamline the process by granting authority for end-users to participate in RTO demand response programs. He recommended this be accomplished by requiring Respondents to file general tariff riders that allow customers with a demand of 5 MW or higher to directly participate in MISO and PJM demand response programs.

In support of his conclusions and recommendations, Mr. Dauphinais testified that demand response provides value to utility customers. He stated that demand response in RTO markets increases the competitiveness of those markets and lowers the purchased energy, operating reserve and capacity costs of the utilities. These lower purchased power costs will be seen by all customers in the near term through the fuel adjustment clauses and other rate trackers, or in the long-term when a utility's base rates are reviewed. Mr. Dauphianis further testified that the lack of such demand response in the RTO markets would be detrimental to customers as they would be paying for higher purchased power costs than necessary. He opined that direct end-use customer participation in RTO demand response on a general basis can be implemented in regulated retail states without introducing retail access or harming utilities and their non-participating customers.

Mr. Dauphinais explained that while the Respondents have demand response tariffs and riders of various types that have provided some opportunity for Indiana Industry to reduce its net cost of electricity, these tariffs and riders generally significantly limit participation and compensation. He testified that it is important to recognize industrial end-use customers are not generally in the business of selling curtailments, but rather to profitably produce their core product. When they curtail their energy consumption, these end-users can incur significant lost production costs and other costs they would not otherwise incur. However, he explained that if the net reduction of electricity cost produced for the customer by such curtailment can significantly exceed the cost that would be incurred by the customer for curtailment, the customer will be generally willing to curtail its consumption.

Mr. Dauphinais stated that the demand response programs of the RTOs provide greater flexibility and the potential for higher compensation than the existing utility demand response tariffs and riders and do not put limits on customer participation. Thus, he stated the RTO programs provide an important new opportunity for industry in Indiana to lower its cost of electricity that is currently not available under the demand response tariffs and riders of the Respondents.

Mr. Dauphinais explained that the current case-by-case approach to direct customer participation in RTO programs should be changed because cooperation is effectively required from the customer's utility in order to minimize the risk of a lengthy contested proceeding before the Commission. He stated that this gives substantial leverage to the utility which can then use the leverage to unduly extract concessions from the customer and destroy the economics of participation. In addition, he stated, the case-by-case approach provides little certainty in advance whether participation will be ultimately approved and, if approved, under what terms and conditions.

Mr. Dauphinais explained that the recommended riders would streamline the process of permitting participation in RTO demand response opportunities. First, it would eliminate the need for the customer to negotiate with the utility eliminating the utility's undue leverage over the customer's participation. Second, it would provide certainty in regard to participation, compensation and other terms and conditions. He said this certainty and transparency would ensure compensation is not unduly drawn off by the utility and allow potential participants to avoid the significant time and expense associated with seeking participation under the current case-by-case approach.

Mr. Dauphinais observed that this would not eliminate Commission oversight over the terms and conditions of participation in RTO demand response because the tariff riders would delineate the terms and conditions of direct participation and would be subject to Commission review and approval. However, Mr. Dauphinais further clarified that the intended purpose of the riders is to allow customers to directly participate in RTO demand response programs through the RTO or via third-party CSPs. Mr. Dauphinais stated that the riders would not be a form of retail access as the participating customer would continue to purchase all of its electricity at retail from its utility at rates regulated by the Commission. Under direct participation, the customer is simply agreeing to reduce its consumption in exchange for compensation from the RTO, a third-party CSP or its utility. He asserted that neither the RTO nor any CSP would be selling or otherwise providing electricity to the participating customer. He further indicated that if the utility or its non-participating customers incurred certain costs due to the way the RTO funds demand response payments, then the costs could be addressed under the terms and conditions of the tariff riders.

Mr. Dauphinais explained that third-party CSPs are not needed to permit participation directly in RTO demand response, but could be helpful toward eliminating or mitigating some of the overhead costs of participation. Therefore, he encouraged the Commission to permit the operation of third-party CSPs in Indiana.

With respect to I&M, which operates in the PJM market, Mr. Dauphinais recommended that I&M be required to file tariffs of general applicability allowing customers with a demand of 5MW or higher to directly participate in the following PJM programs: Emergency Load Response, Economic Load Response ("ELR"), Interruptible Load for Reliability ("ILR") and demand response provisions of its Reliability Pricing Model ("RPM") capacity market, and Operating Reserve Demand Response ("DR").

Mr. Dauphinais explained how the Emergency Load Response program operated and how I&M's load would be impacted by PJM settlements. He stated that as a result of the demand response the utility will earn additional wholesale revenues or avoid additional wholesale costs, which will likely far exceed any retail per kWh revenue that is lost by the utility due to the demand responder's load reduction. He also explained why the rider would not require any special provisions related to compensation and did not need any limitations on the type of load that can participate.

Next, Mr. Dauphinais explained the ELR program and the PJM compensation thereunder. He explained that the payment procedure effectively has PJM pay the utility for its participating customer's load reductions an amount equal to the load reduction times the applicable retail generation and transmission rates avoided by those customers as a result of their load reductions. Thus, he said the cost and revenues the utility experiences are the same as if the load reductions never occurred.

Mr. Dauphinais explained that non-participating customers could not be harmed by PJM make whole payments through balancing operating reserve charges. He said that I&M, and ultimately its customers, are already paying PJM balancing operating reserve charges for make whole payments made to generators in the PJM market and demand response participants located on other utility systems within the PJM footprint.

Mr. Dauphinais testified that, as with the Emergency Load Response, there is no need for the proposed rider to have any special provisions relating to compensation because the net treatment in I&M's settlement with PJM will in effect be to pay I&M the retail revenue it would have earned if its participating customers had not reduced their load. He stated this leaves I&M's revenues and costs unchanged except to the extent the load reductions lower LMP values from where they would have been without the load reductions. To the extent the load reductions lower LMPs and I&M was a net purchaser of energy from PJM, it will see a lower purchased energy cost than it would have seen without the load reductions to the benefit of all of its customers. To the extent I&M was instead a net seller, he noted that I&M's off-system sales margin will be reduced. However, he testified that virtually the entire reduction in margin would occur even without participation of I&M's customers as such participating customers would only be a small part of the overall contribution of demand response within PJM's footprint.

While Mr. Dauphinais testified that there was no need to limit the type of customer load that can be placed under the proposed rider, he stated the terms and conditions of the rider will need to specify that the participant load cannot receive ELR payments in hours where that specific load has been curtailed pursuant to an I&M interruptible retail. Mr. Dauphinais also testified that the retail rates of I&M participating customers do not need to be unbundled. However, he noted that in cases where rates are not unbundled, PJM works with the participant, or its CSP and the LSE as necessary to determine as closely as possible the rate the end-use customer would have paid for the reduced kWh.

Mr. Dauphinais next explained that ILR and DR are ways for demand response to participate in the RPM capacity market. ILR involves the participant committing in advance to curtail load during emergencies when called upon by PJM, for which they are compensated based on the final applicable clearing price for ILR capacity. DR involves offering into the PJM RPM base residual and incremental auctions a commitment to curtail load during emergencies when called upon by PJM, for which participants are compensated at the market clearing price of capacity in the applicable auction if the offer is accepted by PJM.

Mr. Dauphinais testified that for capacity, there would be no adverse impact on I&M if its customers participated in ILR and DR provided only load that I&M does not already count as DR under the PJM Fixed Resource Requirement ("FRR") option is allowed to participate. For energy, Mr. Dauphinais testified that the impact on I&M would be identical to what happens under the Emergency and ELR provisions since the curtailments themselves are settled pursuant to those provisions. Mr. Dauphinais concluded there would be no adverse impact on I&M or its non-participating customers due to allowing direct participation of I&M customers (not already claimed by I&M as DR) in the ILR and DR provisions of the PJM RPM capacity market. As a result, he stated no special provisions would be needed to address compensation issues.

Mr. Dauphinais did indicate there was a need for limitations on the type of customer load that can be placed under the proposed rider. He stated that customer load, which is subject to an interruptible retail rate of I&M and for which I&M counts that load as DR under the PJM FRR option, cannot be allowed to participate under this rider because I&M is already taking credit for the capacity value of those interruption commitments.

Finally, Mr. Dauphinais explained demand response provisions for regulation and synchronized reserves. He testified that the rider for these demand response provisions does not need any special provisions related to compensation. For regulation, the only compensation the participant receives for the load reductions is the avoidance of the per kWh charges under its retail rate. He explained that the participant's utility either is paid the real-time LMP for the load reduction or avoids the payment of the real-time LMP for the load it would have served without the reduction. Mr. Dauphinais stated that the net effect is no different to the utility and its non-participating customers than if the customer's load had been voluntarily reduced for reasons other than demand response. As for synchronized reserves, Mr. Dauphinais explained the payments to participants are funded by those PJM members who have insufficient synchronized reserve credits to cover their allocation of synchronized reserve charges. While the participant's utility may be liable for such charges, he stated it will not be due to the participation of the utility's customers in providing synchronized reserves to PJM. However, Mr. Dauphinais did indicate that limitations may be needed on participation by load served under an interruptible rate by I&M.

With respect to the MISO Utilities, Mr. Dauphinais recommended each utility file tariff riders of general applicability that allow customers with a 5MW or higher demand to directly participate in the MISO Demand Response Resource ("DRR") and the Emergency Demand Response ("EDR"). Because MISO is still developing some demand response provisions, he also recommended the establishment of interim riders for customers to provide and be compensated for: (1) self-scheduled economic curtailments by MISO's energy settlement provisions with the utility acting as market participant, and (2) providing Load Modifying Resources to the utility. Mr. Dauphinais testified the interim riders should expire when: (1) MISO has established reasonable provisions that allow end-use customers to directly participate in ELR and the provision of Load Modifying Resources, (2) the utility establishes a reasonable tariff rider of general applicability that allows end-use customers to directly participate in the MISO's ELR and Load Modifying Resource provisions, and (3) all commitments made under the interim riders have expired.

Mr. Dauphinais provided an overview of MISO's DRR provisions, which consists of two types: Type I and Type II. Type II DRRs are different from Type I DRRs in that they can be dispatched by the MISO anywhere in the range from no curtailment to full curtailment. Type I DRRs can currently offer curtailments in the markets for energy and supplemental operating reserves. Type II DRRs can currently offer curtailments for these two services and, if capable, spinning reserves and regulation. Mr. Dauphinais explained how MISO offers compensation for DRR services.

Mr. Dauphinais testified that based on the way MISO currently contemplates allocating cost and revenues between DRRs, the LSE of those DRRs and the balance of the MISO market, the recommended tariff riders of the MISO Utilities will need special provisions to deal with compensation. He stated that under the MISO approach, the utilities will be held responsible in the MISO day-ahead and real-time markets for the demand of the participating customers' load as if that load was never curtailed. Thus, Mr. Dauphinais explained, the riders of the MISO Utilities will need to contain a compensation adjustment to rectify this issue to avoid shifting fuel and purchased power costs to non-participating customers.

Mr. Dauphinais also testified that the MISO Utilities and non-participating customers would not be harmed by make whole payments through the MISO RSG charges. He stated that the MISO utilities, and ultimately their participating and non-participating customers, are already paying for MISO RSG charges for make whole payments made to generators in the MISO market and DRR participants located on other utility systems within the MISO footprint. However, because MISO does not allow Load Modifying Resources ("LMRs") to also be DRRs, Mr. Dauphinais noted that customer load that is served under a utility interruptible rate and claimed as a utility LMR would need to be excluded from participation under the proposed rider.

Mr. Dauphinais provided an overview of the Midwest ISO EDR provisions, which provides for the Midwest ISO to dispatch curtailments from participant loads during certain emergency events. Mr. Dauphinais explained that no special provisions related to compensation would be needed in the proposed rider. He stated that calls on EDR by MISO of the utilities' participating customers will only be made when those utilities are experiencing an emergency. Under such conditions, these utilities will be purchasing power from the MISO real-time energy market. Thus, he stated, any payment made to EDR participants will be lower than the alternative payment that would need to be made for generation that the MISO would have to call on if the EDR was not participating. However, Mr. Dauphinais did note that customer load that is already on the interruptible rates of the MISO Utilities where the respective utility claims the interruptible customer load as an LMR would not be able to participate under this rider.

Mr. Dauphinais explained that the Industrial Group was proposing the MISO Utilities be required to establish interim riders for ELR because the Midwest ISO currently does not have provisions similar to PJM's ELR provisions. While acknowledging that its proposal goes beyond what is currently available under the MISO tariff provisions, he expressed his belief that there is a need to support participation by loads that are capable of providing ELR, but are not able to meet the MISO requirements for DRR in order to do so.

Mr. Dauphinais explained that while it would be difficult for the MISO utilities to support offer-based curtailment provisions similar to the offer-based curtailment provisions within the PJM ELR program, self-schedule curtailments are readily supportable through the utilities existing energy settlements with the MISO. He explained the Industrial Group's proposal for how participants would elect to participate in self-schedule ELR on a day-to-day basis. He also indicated that the utility would be allowed to recover reasonably incurred administrative costs associated with this rider from participants. The terms and conditions of the rider would also need to specify that rider participant load cannot receive ELR payments in hours where the specific load has been curtailed pursuant to an interruptible retail rate of its utility.

Mr. Dauphinais next explained the Industrial Group's proposal for an interim MISO Utility rider for LMRs. He explained that a customer would work through the utility to qualify the portion of its load that it wants to claim as an LMR with the Midwest ISO. If granted, the participating customer would be paid either the capacity cost avoided by the utility due to it being able to count the LMR to meet its capacity requirements or the price the utility is able to obtain in the market by selling the capacity credit associated with the LMR. He stated the utility would be allowed to recover reasonably incurred administrative costs. However, he noted that customer load that is currently under an interruptible rate of the utility where the utility already claims that load as an LMR with MISO would not be able to participate under this rider. In addition, customer load participating under DRR provisions would not be able to participate in this rider because MISO does not allow DRR to also be LMR.

Mr. Dauphinais then provided hypothetical examples of the impact on a utility and its non-participating customers from allowing direct customer participation in RTO demand response provisions.

Finally, Mr. Dauphinais provided additional testimony concerning the specific issues identified in the February 2, 2009 docket entry. In particular, Mr. Dauphinais expressed his belief that direct end-use customer participation in MISO and PJM demand response programs under the riders proposed would have no effect on utility long-term planning or utility forecasting as participating customers would remain firm customers of their respective utilities for purposes of planning and retail ratemaking. Nor did Mr. Dauphinais perceive the direct participation by end-use customers under the riders proposed in this proceeding as having any impact on a utility's demand side management programs.

Mr. Dauphinais also testified that participating customers should not be required to allow a utility to act as an agent in the customer's participation in the Midwest ISO or PJM demand response programs. He stated that utilities are not uniquely situated to act as an agent on the customer's behalf as larger customers can readily act on their own behalf and CSPs can and do act as an efficient conduit for participation by small and medium-sized customers. In addition, he asserted that placing utilities in a position where they can gain leverage over participants will allow utilities to extract unfair concessions from participants and inhibit participation due to the concessions that need to be made in order to have their utility's cooperation. Mr. Dauphinais does not believe that MISO, PJM or CSPs become regulated public utilities as they are not providing electric service to Indiana end-use customers.

10. Wal-Mart. Kenneth E. Baker he requested that the Commission consider the beneficial impacts that active and robust demand response participation will have in Indiana and surrounding regions, the active measures that end-use customers will take in reducing overall demand, and the reduction in procurement needs of utilities of Indiana. Mr. Baker also requested that the Commission consider reducing impediments and complexities that: (1) discourage end-use customers from participating in demand response programs; or (2) mask the benefits associated with demand response participation to end-use customers. Mr. Baker testified that encouraging competitive options will enhance demand response participation and enable the incorporation of such resources into Indiana's ultimate load reduction programs and goals. He stated that if programs are not properly designed with end-use customer's interests or needs in mind, participation in demand response may be limited.

Mr. Baker testified that Wal-Mart believes it would be appropriate to relieve utilities of the obligation to include the load a participating end-use customer offers into an RTO demand response program because a participating end-use customer is contractually agreeing to curtail load. However, he recognized that an Indiana utility has an obligation to serve all customers within its service area. Thus, he suggested it would be appropriate for customers who fail to reduce load to cover the utilities' costs associated with the additional procurement of energy.

Mr. Baker testified that utilities, as well as third party aggregators, should be allowed to act as agents for customers to participate in RTO demand response programs. He also testified that end-use customers should be permitted to act as their own agent in such programs. He stated that with more options and less competitive impediments, the market will more likely provide viable commercial options to customers. Additional options are needed because of the diverse interests and different nature of customer classes.

Mr. Baker opined that allowing customers to participate in an RTO demand response program does not shift costs, but instead reduces costs for all retail ratepayers. He stated that reducing system demands benefits all consumers by providing additional options to manage growing demand, incentivizing positive consumer action, reducing the need to build additional generation to support customer demands, and reducing greenhouse gas emissions. Additionally, end-use customers participating through CSPs, or through their own direct participation, will bear their own costs, and non-participating retail ratepayers will be sheltered from the costs and will receive the social benefits of reducing demand under peak system conditions.

Finally, Mr. Baker testified that allowing small and medium size customers to participate in an RTO demand response program enables Indiana to capture all available resources and reduce demand on the system. Mr. Baker also testified that Wal-Mart does not believe an RTO, by transacting directly with an end-use customer, infringes on an Indiana utility's exclusive franchise rights or causes the end-use customer or CSP to become a public utility as they are not transmitting, creating or generating energy. Rather, end-use customers are agreeing not to consume energy.

11. PJM. Paul M. Sotkiewicz described generally the benefit of incorporating demand response into the wholesale power markets. He stated the incorporation of demand response allows electric consumers to express their willingness to pay for power, which enhances market efficiency relative to markets where consumer demand is taken as given regardless of price. As consumers are allowed to respond to prices (and provide additional supply), market competitiveness is enhanced, and potential exercises of supplier-market power are checked as any supplier attempts to raise prices will result in a corresponding reduction in demand making such attempts less profitable. At the level of individual consumers, he stated that the incorporation of demand response provides electric consumers the opportunity to control their individual electricity expenditures. According to Dr. Sotkiewicz, if enough customers respond to price, market prices overall may be reduced, and such reductions could eventually be reflected in retail rates.

Dr. Sotkiewicz provided an overview of the demand response opportunities available in PJM, which includes participation in the following PJM Markets: Day-ahead and Real-time Energy Markets; Day-ahead Scheduling Reserves Market ("DASR Market"); Synchronized Reserve Market ("SR Market"); Regulation Market ("Regulation Market"); and the Reliability Pricing Model Capacity Market ("RPM Capacity Market"). He provided detailed explanations of how participation in these markets is structured under the PJM tariffs.

Dr. Sotkiewicz explained that PJM is responsible for resource adequacy planning for the entire PJM RTO footprint. In carrying out this responsibility, he stated that PJM develops load forecasts by electric distribution company ("EDC") zone and RTO-wide, with input from the member EDCs including historical load data. In determining the peak load forecast, PJM develops an "unrestricted peak load" forecast that does not account for demand resources that instead would be included as capacity (supply) for the purposes of meeting resource adequacy requirements. PJM also is responsible for determining the Installed Reserve Margin ("IRM"), which along with the forecast peak load determines the resource adequacy requirements for a given delivery year. Dr. Sotkiewicz explained that PJM's load forecast can be affected in two ways by an end-user's participation in PJM demand response programs: 1) if the end-user participates on an energy-only basis, its reduced load will lower PJM's forecasted peak loads, or 2) if the end-user participates as Load Management, an adjustment will be made to PJM's forecasted peak loads. In either event, he indicated the demand response will serve to lower the amount of supply-side capacity resources needed for resource adequacy.

Dr. Sotkiewicz explained that when a CSP attempts to register a demand resource under PJM's FERC Tariff, PJM will request verification from the appropriate EDC or LSE as to whether the registering demand resource that may be reduced is subject to another contractual obligation, such as a utility demand response program, as well as for confirmation of any associated transmission or distribution charges. If the load is subject to other contractual obligations, then special settlement terms may be used to accommodate those obligations.

With regard to cost-shifting among participants and non-participants, Dr. Sotkiewicz testified that in the ELR program, the savings that accrue to a demand resource, which are paid by the LSE of record, are offset by the avoided cost of the LSE or extra revenue that the LSE could obtain by selling excess power back to the market. So, there is no cost shifting to other LSE customers. He stated that demand resources that offer capacity into the RPM Capacity Market receive revenues that offset the cost of capacity obligations based on their unrestricted peak load. Consequently, such a demand resource retains the same capacity obligation and associated allocated cost as if it were not offering any capacity into the RPM Capacity Market and Dr. Sotkiewicz testified there is no cost shifting between LSE customers due to such participation.

Dr. Sotkiewicz testified that the participation of demand resources in PJM's markets provides a number of benefits. He stated that empowering consumers to reduce demand in response to rising prices may reduce market price volatility, and market prices overall. Additionally, he stated that participation in PJM's demand response programs results in operational savings for EDCs and LSEs (lower energy costs or lower capacity costs or lower ancillary services costs), which those entities may pass through to all retail customers, including non-participating retail customers. Finally, Dr. Sotkiewicz testified that participation in PJM's demand response programs enhances grid reliability and provides potential environmental benefits.

12. Midwest ISO. The Midwest ISO filed a "position statement" signed by Keith A. Beall. The statement indicated that discussions about demand response issues are occurring through the Midwest ISO's stakeholder process, which is open to interested parties. The statement also indicated that the Midwest ISO has been working on compliance with Order 719 of the FERC and that although it is FERC regulated, MISO recognizes the laws and regulations of each of the relevant states in the Midwest ISO footprint that oversees retail rates and choice matters that affect demand response participation and implementation must be respected. The Statement summarized the requirements of Order 719 with respect to demand response, and indicated that the Midwest ISO had circulated a proposal that requires third-party CSPs to certify to the Midwest ISO that the laws and regulations of the state did not preclude the aggregated customers from directly participating in the Midwest ISO markets. It also indicated that the Midwest ISO was working with the Organization of MISO States to develop a process to provide notice to the relevant electric retail regulatory authority.

13. **CPower.** Thomas Rutigliano testified concerning CPower's provision of demand response services, as an aggregator, to commercial and industrial electric customers and identified the PJM and MISO markets in which demand response can participate.

Mr. Rutigliano stated CPower believes that whether the provision of demand response in the RTO markets constitutes a resale of electricity depends upon the product. He stated that demand resources that participate in the synchronized (or spinning) reserve and regulation (ancillary services) markets create new reserve products where none existed before; consequently, no resale is involved. In addition, he indicated that payments for ancillary services are not for energy, but for the readiness to respond on short notice. However, he also indicated that resources (demand or generation) that provide ancillary services do receive a separate energy payment for the actual quantity of MWh incidentally provided, but he characterized such payments as small to the point of near insignificance.

Mr. Rutigliano testified that when demand resources provide capacity, they are increasing the system's ability to meet its peak load. Thus, demand response can create new capacity that did not exist before, suggesting there is no resale. This is because most electrical systems only approach their peak load for a few hours every year. Mr. Rutigliano stated that when an end user commits to reduce its consumption during those hours, it is enabling the system to serve this peak load, with exactly the same result as if a generator had committed to providing power during those hours. Just like for ancillary services, he stated, capacity payments are separate from energy payments. Resources that provide capacity also receive a separate energy payment for power they provide (or do not consume).

Mr. Rutigliano testified that whether demand resources participating in the energy markets constitute a resale of electricity is more ambiguous. He stated that from an accounting perspective, demand response providing energy is identical to a sale for resale, with the demand resource purchasing energy at its retail rate and reselling it at the wholesale rate. However, he noted that a demand resource providing energy also never takes physical possession of the energy involved, and the energy never flows through the customer's facility.

Mr. Rutigliano testified that CPower believes that an unrestricted load approach, which separates demand response as a supply resource from load forecasting and planning, is best for integrating demand response into resource planning. He explained that, under this approach, the amount of power curtailed is added back to a utility's load for reliability planning purposes, and the utility is required to plan to meet this unrestricted load. Where capacity costs are allocated to end-users, they are allocated according to the end-users' unrestricted load to ensure there is no double counting of demand response. He further explained that under this method utilities could opt to procure demand response capacity bilaterally, either through contracts with end-users or through aggregators.

Mr. Rutigliano testified that demand response provides similar products regardless of whether it is organized as a utility interruptible tariff, through an aggregator, or directly to an RTO, and opined that it is important that participation be regulated to ensure that the same demand resource is not double counted. Based on this, he stated that competition between utility tariff based programs and other demand response participation options is likely, and that the results of that competition will be largely determined by how payments under tariff programs compare to the market value of demand response. He further testified that many Indiana utilities only offer demand response opportunities to their largest customers.

Mr. Rutigliano explained that the financial impacts of direct customer participation in RTO demand response programs vary across the demand response markets. He testified that for synchronized reserve, minimal costs are shifted to retail ratepayers due to an incidental energy transaction associated with actual contingencies and a small amount of revenue loss to the host utility. He noted the same applied to regulation reserves, except the energy transaction was a more significant fraction. He stated that capacity markets in MISO were difficult to assess and that the charges in PJM's capacity markets are determined by I&M's choice to meet its capacity planning obligations through the FRR option. Finally, with respect to energy markets, Mr. Rutigliano stated that CPower agrees that the host utility should receive a make-whole payment from the demand resource equal to the generation component of the lost revenue from the energy sale and that any deviation charges should be eliminated or recovered from the demand resource to avoid socialization of such costs across ratepayers. He also noted that PJM has some proposed modifications to its demand response programs that include incentive payments that would also need to be addressed if adopted to avoid socialization across ratepayers.

Mr. Rutigliano testified that he believes demand response to be a beneficial use of electricity, where end-users create valuable products through their own investment of time, money or effort. He opined that utilities should have no more claim on an end-user's demand response products than they have on any other product created using electricity, and that thus there should be no requirement for end-users to use the utility as their agent in participating in RTO programs. He also testified that allowing independent aggregators to act as end-users' agents is in the public interest, as various aggregators offer opportunities to underserved customer classes, bring specialized knowledge regarding demand response in general and its application to specific industries, are highly motivated to seek out demand response opportunities, and may offer superior customer service or have lower administrative costs than utilities.

Mr. Rutigliano suggested it would be more efficient to regulate demand response participation based on programs and tariffs. He testified that a case by case review increases transaction costs for participation and has the potential to reopen issues associated with demand response programs. He stated he believes that PJM demand response markets are developed to the point where it is appropriate to approve participation based on tariff class, and that participation in PJM programs should be allowed for any customer that is not simultaneously participating indirectly through an interruptible tariff. He also indicated that it would be appropriate for the Commission to allow utilities to recover costs incurred for administration and for any cases where the PJM's payment structure imposes costs on the host utility. With respect to the Midwest ISO demand response markets, Mr. Rutigliano opined that it may be premature to define procedures for participation because the markets are currently in transition.

B. The Parties' Responsive Evidence.

1. **MISO Utilities.** Mr. Caister responded to testimony submitted by Mr. Dauphinais, Mr. Satchwell, and Mr. Rutigliano. He agreed with Mr. Rutigliano that demand response has the potential to increase reliability and reduce costs. However, Mr. Caister argued that direct participation limits the potential benefits of demand response to all stakeholders. He testified that such direct participation, as opposed to properly designed demand response participation through the utility, limits the ability of non-participating customers to share in the benefits of demand response programs. Mr. Caister also objected to giving "100 percent" of the benefits to the demand responder, but instead favored allocating them among all stakeholders because the benefits available to the demand responder are due to resources the utilities have financed for the benefit of all customers and the demand for electricity created by non-participating customers.

Mr. Caister disagreed with Mr. Dauphinais that non-participating customers are not impacted if customers are allowed to directly participate in RTO demand response programs. He described how other customers can be made worse off by such factors as deviation penalty, administration, and purchased power costs, as well as being forced to incur increased capacity costs by the switching of certain end-use customers from current utility programs that are credited toward capacity. Mr. Caister also expressed concern that some customers, especially in a fully regulated state like Indiana, will lack the experience or resources to be able to effectively participate directly in demand response programs. Finally, he stated that although the MISO Utilities did not seek to exclude aggregators from working with utilities, he asserted that third party aggregators are unnecessary as the utilities have historically served as aggregators of small customer loads.

Mr. Caister expressed regulatory concerns with Mr. Rutigliano's and Mr. Dauphinais' proposals. He testified that without the public service of the utility to all of its customers, there would be no energy usage for the demand response customer to curtail. Therefore, having the utility act as the agent for the demand response customer allows the utility to better plan for the use of demand response and to allocate the benefits to all customers.

Mr. Caister disagreed with the proposals for developing generic tariff provisions for the MISO Utilities, citing unique customer load characteristics, cost elements and tariff structures. Mr. Caister argued that accommodating such differences would not result in easier regulatory proceedings and would also be likely to favor some customers over others. Mr. Caister further argued that different tariffs would allow the parties to evaluate a variety of approaches and experiences. With respect to Mr. Satchwell's recommended tariff features, Mr. Caister expressed a lack of understanding about flowing the majority of revenues to participating customers, but indicated that participating customers need to receive a sufficient benefit to warrant their interruption. Mr. Caister also expressed concerns with the self-scheduling option and the utility-schedule option that includes an opt-out provision because those proposals may eliminate much of the benefit to the MISO Utilities of demand response.

Mr. Caister offered a set of provisions that the MISO Utilities believed would provide a good framework for developing demand response tariffs. First, he proposed that the MISO Utilities would each establish Retail RTO Demand Response Tariffs (or revise current offerings) that allow ELR options, for customers of 1 MW or larger, under terms which would comply with Midwest ISO requirements. These offerings would be designed to avoid creating costs to utilities greater than costs under current tariff and contract offerings. Second, Mr. Caister described designing the Tariffs in recognition of the costs customers will incur and to encourage participation within reasonable operational limits as determined by the utilities. Third, he stated such Tariffs should be designed to avoid problems with increasing costs for non-participating customers, under recovery for utilities, planning and reliability problems, any potential loss of Commission jurisdiction, and any diminution of incentives for participating in traditional DSM or energy efficiency programs. Compensation should be based on the revenues of Midwest ISO programs, and participating customers would be responsible for any costs. Finally, any double recovery should be avoided, and customer base lines should comply with Midwest ISO rules and be set in a reasonable manner.

Mr. Caister further stressed that the MISO Utilities are willing to work with interested stakeholders, and that they will commit to establish a meeting with stakeholders within thirty days of an order in this Cause. Mr. Caister also did not oppose the three-year trial period suggested by the OUCC. Finally, Mr. Caister testified that the MISO Utilities accepts the OUCC's desired transparency requirements and believes that such transparency goals are furthered when customers participate through the utility.

Mr. Sailers' reply testimony addresses Mr. Dauphinais' recommendations. Mr. Sailers testified that Duke continues to believe that participation in demand response is best structured with Duke as the market participant representing the customer and that tariff riders of general applicability are not reasonable. However, Mr. Sailers indicated that Duke was willing to commit to discuss demand response participation with interested parties within thirty days of an order in this Cause. Mr. Sailer further testified that Duke disagreed with Mr. Dauphinais' recommendations related to ELR for several reasons, including: (1) the lack of an end date for the interim tariffs potentially creates a conflict with future Midwest ISO programs, which are still developing, (2) non-participants could be harmed or benefits erased by certain forms of participation, and (3) allowing too much customer discretion as to when and how to participate may raise serious market issues. Finally, with respect to Mr. Dauphinais' recommendation on LMR, Mr. Sailer noted that Duke already provides several options for participation and has also proposed new programs for participation.

Mr. Haselden and Mr. Ulrey agreed with Mr. Caister's testimony. They both emphasized that customer participation is best structured with the utility as the market participant representing the customer, and disputed the reasonableness of tariff riders of general applicability. Consequently, Mr. Haselden and Mr. Ulrey instead advocated that the utilities engage in further discussions with parties who are interested in their respective programs about appropriate program parameters. They further noted that Mr. Dauphinais' proposals go beyond current MISO demand response programs and do not directly interact with the MISO markets. Although they stated their belief that the specific proposals were beyond the scope of this Cause, they also suggested that certain IPL and Vectren programs are already responsive to Mr. Dauphinais' requests. Mr. Haselden and Mr. Ulrey concluded by indicating that their respective companies were willing to commit to setting meetings to discuss the development of tariff riders within thirty days of a final order in this Cause. However, both witnesses noted that the timing of the completion of such discussions will likely be impacted by the finalization of the Midwest ISO's demand response rules.

2. I&M. Mr. Roush responded to Mr. Satchwell's testimony. Mr. Roush agreed that demand response offers a number of benefits, but disagreed that those benefits are best captured by permitting end-users to participate, directly or through a CSP, in PJM's demand response programs. Mr. Roush stated that such direct end-user participation adds additional complexity and costs and could make economical long-term planning difficult. These problems are avoided and the benefits of demand response preserved, he testified, if the host utility is responsible for managing all customer demand response within its service territory.

Mr. Roush testified that California may serve as an example if the Commission decides that CSPs should be permitted. He stated that it was his understanding that major investor-owned utilities in California were required to issue requests for proposals seeking bids from third-party aggregators to provide firm demand response to the utilities. Citing to a California Commission decision regarding a request filed by Southern California Edison, he asserted that in California CSPs are evaluated against cost-effectiveness, reliability and other criteria in much the same way that other resources are evaluated in the IRP process and the costs of the contracts are recognized in the ratemaking process.

Mr. Roush testified that in traditionally regulated states, participation in PJM demand response programs should be limited to wholesale LSEs within PJM. However, to the extent that the Commission decides to permit retail participation, I&M recommended the Commission require a retail customer or CSP to participate in the PJM demand response programs only through the LSE.

Mr. Roush testified that the OUCC's proposal to require all regulated utilities to offer the exact same demand response tariff offerings is simply not feasible given the wide-ranging and substantial differences between each utility. Generic tariffs, he argued, would likely have to resort to the "lowest common denominator" in terms of program offerings and would likely not be as effective as individually-developed tariffs. In addition, Mr. Roush stated that when an end-use customer participates in a PJM demand response program, I&M incurs costs associated with that participation. Consequently, he asserted that if the Commission orders utilities to develop additional tariffs, such tariffs should be cost-based and fully reflect the cost I&M incurs, including any RTO penalties and all administrative and resource planning costs.

Mr Roush testified that the OUCC's recommendation that CSPs be allowed to operate on a trial basis and only through the LSE is preferable to granting such entities unbridled authority to enroll customers. However, he argued that allowing CSPs to operate as agents for host utilities may add an additional layer of cost and complexity to demand response offerings, which the LSE should be permitted to address as the agency relationships are developed.

With respect to Mr. Satchwell's recommendation that end-use customers be allowed to participate in RTO demand response programs for a trial period, Mr Roush stated that such a proposal could produce unintended consequences. He therefore recommended the Commission reserve the right to make course corrections as necessary throughout the trial period and take steps to assure that the critical information is gathered and shared with the Commission and all Indiana stakeholders, including utilities, for measurement and verification purposes.

Mr. Roush indicated his understanding that Mr. Satchwell's proposal would require the end-use customer or CSP to participate through the LSE, which would allow the use of demand response to be evaluated against other resource options and incorporated into the IRP process. He noted that issues associated with how utilities should incorporate the demand response data into the IRP may be best addressed in the technical workshops scheduled in the Commission's current IRP investigation proceeding. He further testified that if the Commission rejects the OUCC's proposal and authorizes end-use customers and CSPs to participate directly in RTO demand response programs, it should establish and enforce detailed reporting requirements to ensure that the data which the OUCC considers critical is actually reported and shared with the Commission and the utilities.

Mr. Roush agreed with Mr. Satchwell's recommendation that the Commission require a more transparent method of end-use customer notification to all affected parties. He stated the most transparent option is to allow end-users to participate in RTO demand response programs only through their LSE, which remains responsible for ensuring resource adequacy and long-term planning and should remain responsible for managing the demand response resources of its customers. Mr. Roush testified that I&M is not opposed to the OUCC's transparency objective provided the cost of implementing and achieving this objective is borne by the cost causer, *i.e.,* the CSP and/or relevant end-use customer.

Mr. Roush also responded to Mr. Rutigliano's testimony that CPower had registered thirteen Indiana sites under PJM's demand response programs in 2008 without Commission approval. Mr. Roush expressed concern that without Commission oversight, CPower would continue to provide demand response resources into PJM without considering the effect on either, or both, I&M and its non-participating customers. He also indicated that I&M informed PJM that, to the best of I&M's knowledge, these customers had not received Commission approval to participate, but that PJM allowed those customers to participate in the 2008-2009 planning year.

Mr. Roush disagreed that wholesale market participation as encouraged by Mr. Rutigliano was an appropriate method of demand response for a traditionally regulated state. He also disagreed that the Commission has tacitly accepted that there is no requirement for I&M to offer customers with less than 1 MW of curtailable load demand response opportunities.

Under Mr. Rutigliano's unrestricted load approach to resource planning, Mr. Roush argued that I&M would continue to plan for, and submit forecasts based on, a customer's expected load as if no curtailments occur. The problem with this approach, according to Mr. Roush, is that I&M must incur additional costs in planning for this load which ultimately may not be present if the customer chooses to curtail. These additional costs, he testified, could be avoided, and the customer's demand response capabilities incorporated into I&M's long-term planning, if the customer was not allowed to directly participate in PJM's demand response programs.

According to Mr. Roush, Mr. Rutigliano suggested that his approach to resource planning is reasonable because the costs of capacity additions are allocated to all end-use customers under Indiana's traditional retail regulation framework. Mr. Roush stated this approach fails to recognize that capacity additions will be planned for and made without regard to actual curtailments. As a result, he stated, capacity may be added earlier and costs may be higher than necessary if Mr. Rutigliano's approach were adopted. He stated that retail rates could be higher than they would be otherwise if demand response were handled by the LSE.

Mr. Roush disagreed with Mr. Rutigliano's characterization that Indiana's regulatory framework permits utilities to cherry-pick customer classes for demand response offerings. Mr. Roush opined that the Commission has historically balanced demand response offerings with the provision of low cost, efficient and reliable service to all customers, and that the Commission has also taken technology issues and customer demand into account. Mr. Roush also indicated his disagreement with Mr. Rutigliano's contention that whether demand response participation by end-users involves the resale of electricity varies depending on the demand response program. He argued that in each instance, the retail customer must be a purchaser of retail electric service before the customer has something to sell in the wholesale market.

Mr. Roush argued that the selection of the FRR option is consistent with the fact that AEP has resource planning requirements in its regulated states, including Indiana. In addition, he stated the costs and benefits of AEP's use of its interruptible load to meet its FRR obligation accrue entirely to AEP and its customers and are not socialized across other PJM members as indicated by Mr. Rutigliano.

Mr. Roush testified that participation of retail customers in multiple programs presents both technical and administrative complications, and that I&M does not believe it is possible to provide a definite listing, as recommended by Mr. Rutigliano, of which tariffs would or would not result in double counting. Mr. Roush stated that PJM does work diligently with LSE's to make sure that double counting does not occur, but noted that such effort would not be necessary if all demand response is performed through the customer's LSE.

Mr. Roush also disagreed with Mr. Rutigliano's assertions concerning the costs that I&M will bear from an end user's direct participation in PJM demand response programs. Mr. Roush stated that I&M incurs administrative costs to verify a customer's registration with PJM and a customer's load before and during each curtailment; costs which are ultimately borne by all I&M retail customers. In addition, Mr. Roush stated that while PJM demand response participants are able to "resell" their firm energy at market prices, I&M must nonetheless treat their load as firm for capacity planning purposes, thereby incurring costs that could be avoided if the customer participated in an I&M demand response program. He also noted that should incentives be reinstated in PJM's programs through the stakeholder process, there would be additional costs incurred. Thus, he disagreed with Mr. Rutigliano's contention that end-users' participation in demand response programs, directly or through a CSP, does no harm to I&M or other customers.

Mr. Roush also responded to Dr. Sotkiewicz's direct testimony. He expressed disagreement with Dr. Sotkiewicz's statement that demand resources have participation opportunities comparable to those available to generation capacity resources in the PJM markets. Mr. Roush argued that Indiana end-user direct participation as a "demand resource" in the wholesale markets is a one-sided participation and is not comparable. He asserted that allowing direct end-user customer participation in PJM's programs in a regulated state, like Indiana, allows those end-users to profit by reselling electricity purchased at I&M's low retail rates for a profit on the wholesale market. Mr. Roush stated that generation resources in Indiana are regulated by the Commission, and that demand resources should be as well.

Mr. Roush stated that Dr. Sotkiewicz's focus on revenue opportunities for "resource options" fails to recognize that allowing direct participation by end-use customers, who are still taking service under a regulated retail rate, imposes costs on I&M and can ultimately increase other customers' retail rates. He testified that I&M remains obligated to plan for and provide capacity for all of its customers, while those customers electing to participate in PJM's demand response programs can choose to curtail during periods when LMP are high and collect substantial revenues, while also recognizing additional savings by avoiding the retail rate in the demand reduction. He stated that beyond I&M's lost revenues, I&M must incur costs in planning and providing capacity for these customers irrespective of whether they plan on curtailing their demand or not. If, on the other hand, these customers were participating in I&M's demand response offerings, Mr. Roush argued that I&M could incorporate their demand response capabilities into its long-term planning and thereby reduce costs for all customers.

Mr. Roush asserted that Dr. Sotkiewicz's statement that small and medium size customers can participate in PJM's demand response programs and will be exposed to market prices regardless of the market in which they choose to participate is incomplete because it focuses only on the retail customer's resale of power into the wholesale market. Mr. Roush stated that I&M's small and medium size retail customers are not exposed to market prices in their purchase of retail electric service from I&M.

Mr. Roush did not support Mr. Dauphinais' recommendations concerning separate tariff riders for each demand response program or the prohibition against additional requirements. Mr. Roush testified that I&M believes, if direct participation is allowed, that any proposed tariff would need to incorporate additional provisions approved by the Commission to make the total package work for Indiana. He stated that, because PJM's demand response programs were not designed to allow direct participation by customers receiving regulated rates, the Commission should make sure that any participation it does allow is coordinated by the LSE so that the impact on other customers can be managed, and the participating customer's demand response capabilities can be utilized to meet the LSE's capacity obligations. The Commission should, he contended, also ensure that costs caused by the end-user's participation, such as review and verification costs, are borne by the participating retail end-user.

Mr. Roush also disagreed that the current case-by-case approach unduly inhibits participation in RTO demand response programs. Mr. Roush stated that the current process serves the important goal of ensuring direct participation does not adversely impact the utility or non-participants. Mr. Roush argued the most significant barrier to increased demand response participation is a technological one, not a procedural one. He stated that until a "smart grid" is in place, demand response will likely remain unavailable to most electric customers. He testified that a comprehensive coordinated roll-out of smart grid technology makes much more sense to him than a one-at-a-time installation of interval metering on customers which are solicited and registered by a CSP.

Mr. Roush indicated that as a member of the AEP Pool, I&M's situation is unique. Mr. Roush explained that to the extent that I&M and the AEP Pool have excess energy and sell this excess energy in the wholesale market, the net revenue is shared with I&M retail customers through a 50/50 off-system sales sharing mechanism. When an I&M end-use customer resells power that they would normally consume, that excess energy goes outside the AEP Pool and is unavailable for I&M to sell. Mr. Roush contends that what direct participation means, at least for I&M's customers, is that end-use participants are obtaining the profits associated with I&M's low cost of electricity at the expense of the remaining customers who do not participate in demand response programs.

In response to Mr. Dauphinais' testimony that Respondents' demand response tariffs and riders generally significantly limit participation and compensation, Mr Roush stated that these limitations and requirements serve important purposes. Limitations exist to recognize the utility's need for demand response resources, to ensure cost effectiveness of the program, and to ensure that the demand response for which the customer is being compensated for under the tariff or rider is actually achieved. Mr. Roush also disagreed with Mr. Dauphinais that the demand response programs of the RTOs provide greater flexibility and the potential for higher compensation than the existing utility demand response tariffs and riders. Mr. Roush agreed there are some programs, such as a self schedule option, which I&M does not offer that provides additional flexibility; however, he opined that such option also opens the door for significant potential gaming.

Mr. Roush acknowledged that West Virginia, a regulated state, did notify PJM that it did not object to nine customers participating in PJM's Emergency Load Response Program. However, he noted that the West Virginia Commission did not perform an extensive investigation and reserved the right to revisit the issue in a future proceeding. Mr. Roush also disagreed with Mr. Dauphinais' assertion that for industry in Indiana to be competitive, it must have access to the same RTO demand response programs because it fails to consider the regulatory scheme as a whole.

While Mr. Roush agreed with Mr. Dauphinais that CSPs are not necessary for direct participation in RTO demand response, he disagreed that CSPs offer value that cannot be gained by requiring participation through the LSE. He testified that permitting CSPs to operate in Indiana would only add a middleman to these transactions, which could result in higher transaction costs and "demand resources" that are not reasonable and least cost consistent with IRP principles.

Mr. Roush also disagreed with Mr. Dauphinais' recommendation that I&M be required to file tariff riders and to have a standing obligation to file additional tariff riders in the event PJM offers new demand response programs. He argued that the Commission would be required to pre-judge future programs before the facts and impact of such programs are known.

Mr. Roush disagreed with Mr. Dauphinais' testimony that I&M and its non-participating customers are in a win-win position if end-users participate directly in PJM demand response programs. He stated that Mr. Dauphinais provided simplified examples which failed to account for a number of costs that would be borne by I&M and its customers, and which, when combined with the added jurisdictional concerns of allowing CSPs to operate in Indiana, do not support his conclusion. In addition to the added costs, he noted that to the extent I&M is a net seller, I&M's off-system sales margin will be reduced, with a concomitant reduction in shared off-system sales margins for I&M's customers. Mr. Roush disagreed that any reduction in off-system sales margins due to direct customer participation represents margins that the utility should not be earning in the first place. Mr. Roush stated that implicit in Mr. Dauphinais' conclusion is the underlying inappropriate assumption that a directly participating customer is entitled to receive market prices. He testified the conclusion disregards the fact that I&M's customers benefit from off-system sales margins and therefore, all other I&M customers would be harmed in order to benefit the directly participating customer.

With respect to Mr. Dauphinais' testiomny that direct end-use customer participation has no effect on a utility's long term planning, Mr. Roush noted I&M is required by the Commission to include demand response programs in its IRP process. To the extent customers are allowed to participate outside of I&M's demand response offerings, Mr. Roush contends such results in (1) lowered participation in I&M's own programs due to competition; and (2) a reduced ability to delay new generation by relying on customer demand response resources. He also noted that for resource adequacy requirements, I&M is required by PJM's FRR rules to count the load of its direct participants as firm even though they may choose to curtail their load when market conditions provide them with sufficient incentive.

Finally, Mr. Roush disagreed with Mr. Dauphinais that utilities are not uniquely situated to act as an agent on the customer's behalf. He stated that I&M has, over time, developed a reputation for providing low cost, reliable electricity. If CSPs are allowed to freely operate in I&M's service territory, Mr. Roush asserts they will be trading off of I&M's goodwill, and any problems that arise from CSP activity will likely harm I&M's relationships with its customers. He does not believe that allowing I&M to act as an agent in a customer's participation in PJM demand response programs provides I&M leverage over the participants to extract unfair concessions and inhibit participation because I&M is regulated by the Commission. Mr. Roush concluded that allowing utilities to manage the demand response resources of their customers is the best approach to ensuring that such participation does not harm non-participants or the utility's ability to plan for its capacity needs.

3. OUCC. Mr. Satchwell indicated his belief that, on the whole, most parties generally testified in favor of utility-sponsored participation of end-use customers in RTO programs. Mr. Satchwell observed that the utilities expressed concerns about resource adequacy requirements, and testified that such concerns were reasonable based on the current design of the RTO demand response programs, which do not provide assurance that a direct end-use customer's participation may be counted to satisfy those requirements. Mr. Satchwell noted that other parties addressed the need for transparency, which was encouraged in the OUCC's direct testimony, as a means to address resource adequacy concerns. However, Mr. Satchwell took exception to suggestions that demand response programs should be disfavored merely because they do not provide eligible capacity under RTO resource adequacy rules. The limitations of such demand response participation should obviously be taken into account in developing tariffs, but Mr. Satchwell testified that such participation might still provide net benefits to the participating customer, the utility and other customers.

As to the other parties' recommendations concerning generic demand response tariffs, Mr. Satchwell indicated that he disagreed with Mr. Dauphinais' recommended participation level of 5 MW. Noting that Mr. Dauphinais did not object to allowing participation by smaller customers, Mr. Satchwell recommended the Commission allow a minimum aggregated demand of 1 MW because of the additional benefits such customers will bring to the RTO markets and the additional data. He also agreed that generic tariff offerings would negate the need for case-by-case review, thereby addressing any alleged barriers to end-use customer entry and leading to increased regulatory efficiencies. In addition, he testified that he believed the issues raised by the municipal and electric cooperative utilities concerning lost margins and decoupled rate design are being appropriately considered in Cause No. 42693 Phase II.

Finally, with respect to CSPs, Mr. Satchwell suggested that most of the concerns raised by other parties could be addressed by his recommendation that CSPs only participate as agents or contractors of the LSE, and that such participation did not appear to raise issues about whether they should be subject to retail regulatory jurisdiction.

4. Industrial Group. Mr. Dauphinais restated the recommendations presented in his direct testimony and indicated that if the Commission should decide not to allow direct customer participation in RTO demand response programs, then the Commission should require Respondents to file tariffs allowing for customer participation through Respondents that is comparable to direct participation. Mr. Dauphinais then responded to the testimony of I&M, the MISO Utilities, and the OUCC.

Mr. Dauphinais disagreed with I&M's belief that RTO demand response opportunities do not work effectively in regulated jurisdictions like Indiana. Mr. Dauphinais, referring to his direct testimony, testified that direct end-use customer participation in RTO demand response programs on a general basis can be implemented in regulated retail states without introducing retail access or harming utilities and their non-participating customers. He testified that allowing direct access to RTO demand response programs in Indiana would provide a new tool for Indiana industry to lower its overall cost that otherwise would not be available.

Mr. Dauphinais stated that Mr. Roush mischaracterizes RTO demand response programs as arbitrage opportunities that allow the participant to profit from the difference between market prices and embedded average cost. Mr. Dauphinais acknowledged that a customer curtailing consumption under these programs will receive revenue equal to the difference between market prices and average embedded cost, but stated this revenue is not profit. He emphasized that industrial customers are generally not in the business of selling curtailments, but are principally in business to profitably produce their core product. Consequently, he stated, customers are only going to exercise their right not to consume energy when the net revenue they receive for the curtailment significantly exceeds the additional costs it will incur due to that curtailment. In addition, Mr. Dauphinais testified that whether these customers consume energy or not, they are responsible through sometimes ratcheted demand charges for the average embedded fixed costs of the capacity that provides the energy.

Mr. Dauphinais also took issue with I&M's claim that customers will have no incentive to work within I&M's existing tariffs if customers are allowed to participate in RTO demand response programs. Mr. Dauphinais opined that if I&M offered demand response tariffs and riders that (i) properly reflected the value that would be provided from such demand response, (ii) had a diverse selection at least comparable to those of PJM and (iii) had reasonable terms and conditions for participation perhaps the Industrial Group would not be pursuing direct participation in PJM demand response programs and more of its members would be taking service under such demand response tariffs and riders.

Mr. Dauphianis also disagreed with Mr. Roush's assertion that I&M customers participating in PJM demand response would benefit at the expense of I&M's other customers. He said the proper test of determining harm is to consider the situation with and without PJM demand response participation. He stated that with direct customer participation as he proposes, participating customers would continue to take firm service from I&M and make the same contribution toward I&M's revenue requirement. In addition, to the extent I&M through its parent AEP is purchasing power from PJM, he pointed out that I&M and its non-participating customers may benefit from lower fuel and purchased power charges due to the demand response. Thus, he concluded, I&M and non-participating customers cannot be harmed, and will only be helped by allowing direct participation in PJM demand response programs.

Mr. Dauphinais disagreed that direct participation could be equated to customer choice or deregulation of electric service. He stated that under direct participation in RTO demand response provisions, the customer does not get to choose when it is in the market and when it is on regulated service. He noted that the only choice the customer would have is whether to participate in PJM demand response under the I&M riders recommended in this proceeding.

Mr. Dauphinais disagreed that participating in PJM demand response opportunities would be a resale of retail electric service. As to Mr. Roush's contention that FERC defines demand response as a resale of energy, he asserted that I&M selected one small component of FERC's comments on its jurisdiction over demand response. Quoting from an article of FERC Chairman Wellinghoff, Mr. Dauphinais explained that FERC recognizes several bases for exercising jurisdiction over demand response in the wholesale market.

Mr. Dauphinais, agreeing with Mr. Roush's comment that participants in demand response programs "receive market prices for their foregone energy usage," expressed his belief that end-use customers are not reselling energy, but are selling their willingness to not consume energy. Mr. Dauphinais went on to explain the bases for his conclusion that end-use customer participation in an RTO demand response program is not a reselling of energy into the wholesale market. First, an end-user does not receive power when it participates in a demand response program; because there is no sale to the end-user, there can be no resale by the end-user. Second, an end-user can not sell energy it didn't produce and has no title to under prevailing law. Third, Mr. Dauphinais argued that I&M's contradictory positions at FERC should result in a prompt rejection of its "resale" argument. Finally, Mr. Dauphinais stated that PJM does not compensate end-use participants for energy sold to PJM; rather, PJM compensates participants for not consuming energy. Mr. Dauphinais urged the Commission to reject the "resale" argument but noted that even if the Commission concluded that the participation could be viewed as a purchase of energy at retail and a sale of energy at wholesale, this does not mean this is a prohibited resale of retail electric service and would not be under the terms of I&M's tariff if the Commission chooses to allow such participation.

Mr. Dauphinais called I&M's suggestion that end-users and CSPs would be claiming control of I&M's generation to be a mischaracterization of direct participation in RTO demand response programs. He testified that neither the customer nor a third-party CSP is claiming control over I&M's generation. Instead, he said, the customer is seeking payment from the RTO in exchange for the cost it incurs to exercise its right not to consume energy from the capacity for which it pays demand charges.

Mr. Dauphinais disagreed that end-users should be required to participate only in I&M demand response programs. He testified that allowing direct participation will maximize demand response participation as some end-use customers may elect to participate in RTO programs while others will choose utility programs. Mr. Dauphinais stated that participation in both will lead to a realization of the full potential benefits of demand response accruing to all electricity consumers through lower purchased power costs.

As to I&M's concern that it might incur administrative costs from direct participation, Mr. Dauphinais stated that to the extent I&M reasonably incurred such administrative expenses and was able to demonstrate to the Commission that those expenses would not have been incurred but for customer participation in the RTO demand response programs, I&M could seek recovery of those costs under the tariff riders that the Industrial Group proposed in this proceeding.

Mr. Dauphinais testified that I&M's claim that the cost of including the participating customer's load in I&M's capacity obligation could be avoided if the customer participated in an I&M demand response program is based on the premise that if a customer cannot directly participate in PJM demand response, it will participate in I&M's programs. He noted that this would not necessarily be the case. First, he stated that I&M may not be willing to offer the same flexibility and compensation that the customer can receive under the PJM demand response programs. In addition, not all customers are interested in mandatory curtailment during emergencies. Mr. Dauphinais also testified that I&M and its non-participating customers are not harmed under the Industrial Group's proposal even if I&M has to carry a capacity obligation for participating load because I&M will continue to collect undiscounted firm demand charges from these customers.

Mr. Dauphinais also disagreed that allowing direct participation in PJM demand response programs would increase the cost for all customers over the long-term. He stated that I&M would be obligated to carry capacity for a customer load whether or not it participates in RTO demand response programs and therefore, I&M is indifferent in its planning in regard to whether the customer load in the future participates in PJM demand response or not. Mr. Dauphinais indicated the key is that I&M's non-participating customers are not harmed if I&M has to carry a capacity obligation for participating customers as long as participating customers continue to pay firm rates. He explained that to the extent there is any issue with planning, it is in the context of uncertainty in regard to existing I&M interruptible customers moving to firm service.

Mr. Dauphinais addressed Mr. Caister's assertion that when the MISO Utilities act as the aggregator for demand response, all customers benefit because the utility can monitor the impact of reduction and make adjustments to avoid significant imbalances and shifts in costs between customers. Mr. Dauphinais testified that this might be accurate if MISO did not operate the energy markets and the utilities were still balancing authorities responsible for meeting control performance standards. However, under the ASM, MISO is responsible for dispatching generation and deploying demand response that has been offered into its day-ahead and real-time energy markets and is the responsible party for deploying operating reserves to keep supply and demand in balance on a moment-to-moment basis. Mr. Dauphinais stated that this was also true with respect to Mr. Caister's suggestion that utility sponsored demand response can minimize costs to all customers because predictable planned reductions allow the utility to avoid higher purchased power costs during peak hours.

Mr. Dauphinais expressed appreciation for the MISO Utilities' willingness to develop reasonable rules with customers to facilitate participation in MISO demand response. However, he believed that only allowing participation in MISO demand response programs through the MISO Utilities was a second best solution. While acknowledging the MISO Utilities were not I&M, he stated that the experience to date of Industrial Group members who have attempted participation in PJM demand response has been unacceptable. He noted that I&M has yet to offer demand response tariffs that are comparable to direct participation; nor has it established tariffs that allow customers to participate in PJM demand response programs through I&M. He also noted that while I&M has agreed to allow certain customers to participate in PJM demand response on a temporary basis, I&M has generally been an obstacle to participation in these PJM programs.

Based on this experience with I&M, Mr. Dauphinais testified that the Industrial Group was concerned that, if the Commission mandates customer participation through the Respondents, Respondents will have a greater ability to add additional interruptibility requirements, siphon off compensation from the RTO intended for participating customers or introduce other terms, conditions or charges that unduly inhibit customer participation in RTO demand response. In addition, he testified that such an approach would leave little or no role for CSPs, which could assist in unlocking demand response opportunities for smaller customers. Consequently, Mr. Dauphinais testified, such issues can be avoided under the Industrial Group's recommended approach where utility tariff riders of general applicability are established to allow direct participation by customers in RTO demand response programs.

Mr. Dauphinais disagreed with Ms. Parsley's suggestion that MISO Utilities and customers would be at risk for penalties due to inaccurate peak load forecasts under the MISO tariff. Citing to the lack of a specific MISO tariff provision and expressing his doubts with Ms. Parsley's claim, he noted that to the extent the Commission has any concern, it is an issue that can be resolved in the recommended tariffs.

Mr. Dauphinais testified that Ms. Parsley's concerns with overstating the load forecast were not valid concerns. He stated that depending on the specific MISO demand provisions, RSG charges might be incurred and an excess day-ahead load bid may exist that would be settled in the MISO real-time market. However, Mr. Dauphinais testified that he had already factored these issues into the Industrial Group's proposal. Any deviations in real-time will fall out of MISO settlement and to the extent RSG charges are incurred by the utility that would not have to be incurred but for customer participation in the MISO demand response provisions, those charges would be assigned to the participating customer either directly through MISO settlement or indirectly through a compensation adjustment under the proposed tariff riders.

Mr. Dauphinais responded to Ms. Parsley's example of what might happen if a utility called an interruption to eliminate real-time deviation. He testified that such an example was not realistic because it assumes the utility knows its load forecast deviation far enough in advance to call the interruption, can call an interruption of a specific amount of MW and would call such interruptions to correct load forecast errors. Thus, Mr. Dauphinais testified, utilities cannot practically use their interruptible customers to correct for load forecast error.

In another example offered by Ms. Parsley regarding migration, Mr. Dauphinais noted that it appears she assumed the customer moved from one utility rate where the customer was counted by the utility as an LMR to another utility rate where the utility counts the customer as a DRR under the MISO tariff. He stated that Ms. Parsley was correct that a DRR qualified as a capacity resource would provide less capacity value than a comparably sized LMR. However, such a DRR may provide a greater total net value to the utility than if it was an LMR because the utility could also potentially use the DRR to participate in MISO's energy and operating reserve markets. Mr. Dauphinais stated this was a matter of rate design, and was unrelated to direct customer participation in MISO demand response programs.

Mr. Dauphinais testified that the Industrial's Group's proposal considers Ms. Parsley's concerns that the costs the utility incurs as a result of direct customer participation will be paid by non-participating customers and addresses those concerns by providing for a compensation adjustment. He stated that the proposed tariff riders address those situations where the utility and its non-participating customers experience net costs, including administrative expenses, they would not have experienced but for direct customer participation in MISO demand response programs.

With respect to Ms. Parsley's example of how settlement charges work under a utility rate that has been amended to permit the customer to receive a material amount of benefits without shifting costs to others, Mr. Dauphinais pointed out what he believed to be inaccuracies with the example. He explained why no RSG charge would be incurred by the utility for the curtailment of the DRR. He also disagreed with her deduction of the "Day-Ahead Purchase" amount for the curtailed DRR MWh and the "Lost Margin on Retail Sales" for the curtailed MWh and explained a much simpler, more direct and accurate approach was to simply charge the DRR the per kWh retail rate amount it avoided by the curtailment. He stated this would ensure that the utility neither receives more nor less retail revenue than it would have received if the DRR was not curtailed.

Responding to Mr. Sailers' discussion of demand response programs offered by Duke, Mr. Dauphinais stated that such programs do not offer the same flexibility and compensation that would be available under MISO demand response. He opined that customers should be permitted to decide whether to participate in the demand response programs of their utilities, the applicable RTO, or both.

Finally, Mr. Dauphinais testified that he did not believe the proposal outlined by the OUCC could work because it did not line up well with existing RTO demand response provisions or RTO energy settlement provisions. In addition, he noted that although the OUCC proposal would assign the "majority" of "revenues" to participating customers, it was unclear as to what was meant by either "majority" or "revenues." Mr. Dauphinais explained that he understood Mr. Satchwell's recommendation to be that the Commission require the Respondents to establish tariffs that allow participation in RTO demand response programs through the Respondents. Mr. Dauphinais reiterated the reasons for the Industrial Group's concerns with such an approach.

5. **Wal-Mart.** Mr. Baker testified that Wal-Mart generally supports the testimony of Mr. Dauphinais on behalf of the Industrial Group. He also indicated that Wal-Mart believes Mr. Satchwell's recommendations are an important first step towards encouraging demand response participation in Indiana and eliminating existing barriers to demand response programs for end use customers. However, Mr. Baker requested that, in creating a generic demand response tariff, the Commission ensure such tariffs not include discretionary language that utilities can use to preclude or hinder participation. Mr. Baker also expressed concern that the OUCC's proposal to limit end-use participation to a minimum size of 1 MW would unduly preclude certain end-use customers from participating, whereas all end-use customers should be able to participate.

Finally, Mr. Baker disagreed that CSPs should be required to be agents of a utility in order to participate. He stated that Wal-Mart believes that an end-use customer should be able to elect how its participation in demand response should occur. However, he stated, if the Commission develops a process for CSPs to participate as agents of the utilities, such process should be open and transparent to ensure utility cooperation.

6. **PJM.** Peter L. Langbein disagreed that PJM demand response programs are only designed for deregulated retail jurisdictions and therefore not effective for customers in regulated retail jurisdictions such as Indiana. He argued that the market rules were specifically designed to allow all demand resources to participate in the PJM wholesale markets, irrespective of the status of deregulation in the various retail jurisdictions. He expressed his belief that the current market rules align the benefit and cost of demand resource participation in the various PJM markets on a consistent and equitable basis for either a regulated or deregulated retail

electricity jurisdiction.

Mr. Langbein also disagreed that RTO demand response program participation should be limited to only industrial and large commercial customers. He explained that PJM currently has a variety of end-use customers that successfully participate through a CSP, including homeowners; small commercial facilities, such as convenience stores; schools; large metropolitan office buildings; and complex industrial sites, such as steel mills.

Mr. Langbein testified that CSPs provide a vital role in the PJM Market. He stated that CSPs identify demand response opportunities for individual customers and implement the necessary equipment, operational processes and/or systems to enable demand response. Further, the CSP works individual customers to determine the customer's needs and capability, aggregates the resource where necessary, and offers into the appropriate market to convert demand response capability into value for the market and the customer. Mr. Langbein explained that this requires a full understanding of all wholesale market rules and procedures for demand resource participation. He also testified that CSPs develop specialized processes and applications of technology for specific market segments that maximize the value of customers' demand reduction capabilities, which enable and enhance participation in the energy, capacity, and synchronized reserve markets. He noted as an example that CSPs have focused on the load reduction capabilities of lighting, heating, ventilation, air conditioning and refrigeration in grocery stores.

Mr. Langbein expressed his opinion that customers receiving service under regulated rates and participating in PJM's demand response programs are not reselling electricity. He stated that demand resources participating in the PJM wholesale markets have agreed to not consume electricity; therefore, neither the CSP nor the end use customer purchases electricity and then resells it in the market. A CSP is compensated, he explained, and other wholesale market participants are charged, for providing this service to the PJM wholesale market.

Mr. Langbein testified that PJM does not believe there is cost shifting to other LSE customers from end-user participation in RTO demand response programs. He noted that PJM's direct testimony explained various indirect benefits that non-participating retail ratepayers receive as a result of customer participation in PJM demand response programs and explained the PJM demand response settlement process. Mr. Langbein stated that LSEs may have either avoided costs or received additional revenue, but either way costs are not shifted to the non-participating retail ratepayers.

Mr. Langbein explained that PJM's rules permit a customer participating under a regulated retail interruptible tariff to also participate in a PJM demand response program. He noted, however, that PJM does not accept registration of two CSPs for the same demand resource. He stated that under the current PJM Operating Agreement, for both ELR and Emergency Load Response participants, notice is provided to the appropriate EDC/LSE, and the EDC/LSE provides verification as to whether the demand resource is subject to another contractual obligation and confirmation of any associated transmission or distribution charges. If there are other contractual obligations, a resource may still participate in PJM demand response programs, but PJM has the authority to require special settlement terms to accommodate the contractual obligations. He noted that I&M correctly points out the extra effort required to accommodate contractual obligations, but stated once these matters are resolved the customer gains the ability to further reduce its expenditures for electric service.

7. **CPower.** Mr. Rutigliano disagreed with Mr. Roush's assertion that end-use customer participation in RTO demand response programs does not work effectively in regulated states. He stated that although customers in deregulated states are subject to market prices for electricity, the majority of such customers participating in PJM's demand response programs receive service under fixed demand and energy rate tariffs. He also testified that contrary to Mr. Roush's claim, PJM has designed their demand response programs to work with embedded cost average rates.

Mr. Rutigliano objected to I&M's characterization of demand response as arbitrage, testifying that, contrary to Mr. Roush's claims, demand response participants adjust their consumption based on the cost of electricity relative to the value they gain from consumption. He also disagreed that participation in RTO demand response involves a resale of electricity. He stated that although demand response participation is the accounting equivalent to resale, it is not a physical resale.

Mr. Rutigliano disagreed with two aspects of I&M's characterization of CSPs. First, he stated that contrary to Mr. Roush's statement, CSPs do make investments to provide demand response services by investing in identifying, recruiting and training participants; engineering to develop curtailment plants; physical plant for metering and controls; and computer, communications, and operational systems to dispatch participants when called upon. Second, he stated that CPower makes no claim to control I&M's generation; instead CPower claims control over customer's facilities sufficient to create reserves and capacity products for sale into the wholesale markets.

Mr. Rutigliano testified that I&M's proposal is a request to extend its monopoly franchise on the provision of electric service to a monopoly on the sale of demand response products. Mr. Rutigliano further testified that because such a monopoly will raise costs and inhibit the provision of demand response, it is not in the public interest. He also suggested that because demand response competes with generation and I&M owns generation, there would be a conflict of interest in giving I&M the power to suppress demand response. Mr. Rutigliano further cited to Kentucky as a state that has barred end-users from direct participation and has had little or no development of demand response resources.

Responding to Mr. Roush's concerns that I&M's demand response offerings may be outbid by PJM's demand response programs, he stated CPower believes those concerns indicate that I&M is aware that it is paying its demand response participants less than market value for their products. He likewise responded to Mr. Roush's claim that capacity created by I&M customers directly participating in I&M programs was "useless" to I&M, and stated that I&M was as free as any other PJM member to purchase that capacity at prevailing market prices. Mr. Rutigliano opined that I&M would benefit from a captive customer base by paying those customers less for their demand response than such products would be worth on the open market.

Mr. Rutigliano testified that if the Commission should prohibit direct end-use customer participation, it should require certain measures to minimize the potential for public harm. He recommended that I&M be required to: provide demand response opportunities for all customer classes; offer its customers access to all of PJM's demand response programs; pay a fixed percentage of the PJM market price for demand response products; not recover any of the costs of its demand response program from non-participating customers.

With respect to the MISO Utilities, Mr. Rutigliano testified that CPower agrees that it is not currently possible to state with any certainty the effect direct end-user participation in MISO markets will have on cost allocation, non-participating customers, and resource adequacy planning. He also agreed that, currently, the MISO Utilities represent the most appropriate means to facilitate demand response programs to Indiana customers and that allowing CSPs to operate in cooperation with the utilities could increase demand response.

Finally, Mr. Rutigliano responded to the OUCC's proposal by stating such an approach may be appropriate for the MISO Utilities where the MISO programs are still in development, but it would be unnecessarily burdensome in PJM, where the demand response markets are well-developed and supported by a majority of the state commissions in the PJM footprint. He also disagreed with the OUCC's proposed minimum size of 1MW for participation, believing the markets participants should determine what size is feasible. He concluded by explaining why he disagreed with the OUCC's characterization of demand response as a natural monopoly.

4. <u>Commission Discussion and Findings.</u>

A. Background. As noted above, in Cause No. 43426, the Industrial Group advocated that Commission approval of participation in the MISO ASM be conditioned upon the MISO Utilities' individual tariffs providing the opportunity for their respective retail customers to participate in the MISO's demand response programs. Although the Commission denied the Industrial Group's proposal to require the MISO Utilities to modify their respective tariffs, we found:

> . . . demand response resources and measures are becoming increasingly prevalent, [and that the Commission] should further evaluate possible procedures for considering and, if appropriate, streamlining requests by end-use customers seeking to participate in the various demand response programs offered by RTOs in Indiana. Therefore, we find that the Commission should commence an investigation within thirty (30) days of this Order to examine any and all issues associated with an end-use customer's participation in demand response programs offered by the Midwest ISO and the PJM Interconnection.

Phase I Order at p. 19.

Our action was consistent with Section 1252(e)(3) of the Energy Policy Act of 2005 ("EPAct 2005"), which required FERC to prepare a report by appropriate region assessing electric demand response resources, including those available from all consumer classes. Section 529 of the Energy Independence and Security Act ("EISA") required FERC to complete a National Assessment of Demand Response. FERC has defined demand response as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy."[3]

We note that FERC is working to ensure the comparable treatment of demand response resources in wholesale markets. On October 17, 2008, FERC issued a final rule ("Order 719") on competition in organized markets that, in part, removes several barriers to demand response participation in the organized wholesale markets.[4] Among other provisions, the rule requires all RTOs and independent system operators under FERC's jurisdiction to allow comparable treatment of demand response resources in ancillary services markets and to eliminate certain charges to buyers for reducing load during a system emergency. FERC also changed the pricing rules as necessary to allow the market price of power to reflect the value of lost load during an operating reserve shortage.[5]

Similarly, the Commission has been working to address demand side measures in Indiana. In accordance with Ind. Code § 8-1-2-58, the Commission recently concluded an investigation into the effectiveness of DSM programs offered in the State of Indiana. In its April 23, 2008 Phase I Order in Cause No. 42693, the Commission found that: an inconsistent patchwork of DSM programs existed within the state; Indiana lagged behind not only its neighbors, but also the nation, with respect to spending on DSM; Indiana's energy environment is characterized by low energy prices and high energy consumption; and that additional benefits, such as keeping energy costs low and mitigating environmental issues, could be obtained with increased utilization of DSM programs. *In the Matter of the Commission's Investigation Into the Effectiveness of DSM Programs*, Cause No. 42693, Phase I Order p. 29-31 (IURC 04/23/2008). Consistent with those findings and in an effort to increase and improve DSM programs in Indiana, the Commission's December 9, 2009 Phase II Order found that Indiana law required jurisdictional utilities to pursue all cost-effective DSM programs in their assigned service territories and to make DSM offerings available to all customer classes and market segments. *In the Matter of the Commission's Investigation Into the Effectiveness of DSM Programs*, Cause No. 42693, Phase II Order, pp. 29, 35 (IURC 12/09/2009). It also established, among other things, an overall annual energy savings goal and Core DSM programs to be offered throughout the State by jurisdictional electric utilities. *Id.*

The Commission has also approved the participation of several retail industrial customers in certain PJM demand response programs through individually docketed proceedings. *See, In re Petition of Steel Dynamics, Inc.,* Cause No. 43138 (IURC, 07/25/2007); *In re Joint Petition of Indiana Michigan Power Co. and I/N Tek*, Cause No. 43330 (IURC, 08/08/2007); *In re Petition of AK Steel Corporation*, Cause No. 43503 (IURC, 09/03/2008).

No party to this proceeding contested that there is an emerging opportunity to encourage and expand demand response. The Commission finds that encouraging participation in the

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[3] 18 CFR § 35.28(b)(4); *see also,* http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

[4] *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071 (2008).

[5] We note that FERC has also recently issued a proposed rule to further address demand response resource compensation. *See*, 75 Fed. Reg. 15,362 (March 29, 2010).

various demand response programs or provisions offered by RTOs in Indiana is in the public interest, consistent with the Commission's Orders in Cause No. 42693 and the guidance of EPAct 2005 and EISA.

B. Utility Regulation in Indiana. In Indiana, customers cannot choose their electric service provider or purchase electricity directly from the wholesale electricity market. Rather, Indiana follows what is often referred to as the traditional form of utility regulation. This "comprehensive scheme for the regulation of public utilities . . . ensure[s] that the public is provided reasonable and adequate utility service at reasonable rates, while at the same time ensuring the utilities' investors a reasonable rate of return on their investment." *U.S. Steel Corp. v. Northern Ind. Pub. Serv. Co.*, 486 N.E.2d 1082, 1087 (Ind. Ct. App. 1985) quoting *Illinois-Indiana Cable Television Ass'n., Inc. v. P.S.C.I.*, 427 N.E.2d 1100, 1106 (Ind. Ct. App. 1981).

The Electricity Suppliers' Service Area Assignments Act, Ind. Code § 8-1-2.3 *et seq.* ("Service Area Act"), provides that the Respondent Utilities have the sole right to furnish retail electric service within their respective assigned service areas. Indiana law declares this traditional monopoly structure to be "in the public interest" and unalterable by the authority granted to the Commission in Ind. Code § 8-1-2.5 *et seq.* Ind. Code §§ 8-1-2.3-1; 8-1-2.5-11. The Service Area Act is a cornerstone of Indiana's retail electric utility service framework. Assigned service areas were created to provide for the "orderly development of coordinated statewide electric service at retail, to eliminate or avoid unnecessary duplication of electric utility facilities, to prevent the waste of material and resources, and to promote economical, efficient, and adequate electric service to the public." Ind. Code § 8-1-2.3-1. We have previously recognized the Service Area Act "as an orderly expression of the Indiana General Assembly's intent to enact a statute which balances the electricity supplier's interest in the assignment of definite service areas with the public interest in receiving efficient, economical and adequate service." *In re Assignment of Elec. Suppliers Service Areas*, Cause No. 36299-S-209(X), 1984 Ind. PUC LEXIS 42, *31 (IURC 12/10/1984).

In accordance with Indiana's public policy decision to grant monopoly service areas to utilities for the provision of retail electric service, the Commission is charged with the regulation of those utilities to ensure reasonably adequate service and facilities, and that any charge for services rendered is reasonable and just. *See,* Ind. Code § 8-1-2-4; *Office of Util. Consumer Counselor v. PSI, Inc.,* 463 N.E.2d 499, 503 (Ind. Ct. App. 1984) (finding that "[t]he Commission's purpose is to insure that public utilities provide constant, reliable and efficient service to its customers....."); Ind. Code §§ 8-1-2-58, 8-1-2-68, and 8-1-2-69. Consequently, the Commission exercises broad oversight of retail electric sales and service in Indiana, which follows a traditional cost-of-service model. *In re Verified Petition of Duke Energy Ind., Inc. et al.,* Cause No. 43426 Phase I Order at p. 18 (IURC 08/13/08).

C. Traditional Utility Regulation and Demand Response. Respondent Utilities, as the mandatory providers of electric service to all customers within their certificated service areas, have the obligation to plan for and serve end-use customers' demand. In meeting their public service obligation, electric utilities have for decades fashioned tariffs, special contracts and programs designed to foster customer demand response. The demand reductions and resulting cost savings of these Commission-approved mechanisms are engrained in the electric utilities' cost of service to customers and in short and long-term energy and capacity planning.

The reasonable minimization of purchased power costs and minimization of the need for new generation is part of Indiana's traditional utility regulatory framework.

As demonstrated by the evidence, Indiana electric utilities have for many years obtained demand response from retail customers through tariff-based demand response options, including DSM, special contracts, and interruptible rates. MISO Utilities Ex. 1 at 8. I&M for example has 294 MW of interruptible retail load. I&M Ex. 1 at 13. These mechanisms may offer retail customers price reductions in their cost for service or may offer incentives for interruption, *e.g.,* direct load control programs. Whether price-based or incentive-based, these mechanisms provide the opportunity for Indiana electric utilities to treat retail load reductions as a supply alternative. MISO Utilities Ex. 1 at 8. The demand reduction achieved through these utility mechanisms generally occurs during times of high system demand, which corresponds to periods in which the cost of purchasing power in the wholesale market is generally at its highest. As currently administered, these utility-sponsored demand response mechanisms have been found to benefit all stakeholders. Participating customers receive price reductions or incentive payments, while all other stakeholders benefit by minimizing the need for and cost of additional purchased power. *Id.* at 9-10. Importantly, the Commission has approved the terms and conditions of these mechanisms in docketed proceedings when fully informed of utility costs, cost of service allocations, and risk. Thus, we have been able to ensure that DSM, and specifically demand response, is obtained in a manner that properly balances the benefits and costs for all utility customers.

Current utility-sponsored demand response mechanisms also benefit all stakeholders by reducing or delaying the need for new generating capacity. Long-term resource planning for electric utilities in Indiana is driven to a significant degree by the IRP process defined by the Commission's Rules. An integral component of the IRP in Indiana is that the evaluation of supply and demand side resources is to be undertaken with cost effectiveness in mind. Specifically, 170 IAC § 4-7-1(s) defines "integrated resource planning" to be "a utility's assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs." As part of biennial IRP filings, those electric utilities that are required to file an IRP must provide a wide range of documents and exhibits corresponding to a twenty-year planning horizon. 170 IAC § 4-7-4. Included among that documentation are forecasts of future load and projections of supply and demand side resources necessary to cost effectively meet that load.

This IRP process is part of Indiana's traditional regulatory compact used to help ensure that long range needs are met for the expansion of, and planning for, generating facilities necessary to meet future requirements of electricity. For each year of the IRP planning period, the electric utility must provide a description of its electric power resources, including alternative methods of meeting future demands for electric service, such as customer demand response. As such, existing demand response mechanisms, as well as the utility's projection of additional demand response over time, are embedded in the IRP process as a resource available to meet system demand or as a reduction in demand requirements. The result is the more an Indiana electric utility can cost effectively rely on the demand response of its retail customers, the more it can delay or avoid the need for more costly, additional generating capacity. This delay or avoidance of new generating capacity reduces costs for all Indiana stakeholders.

As an outgrowth of this planning process, when a utility proposes to construct new generation, all supply and demand side alternatives are considered to ensure the most cost effective solution is selected to meet customer demand. Under Ind. Code § 8-1-8.5-3(b)(5), before approving a certificate for a new power plant, the Commission engages in an analysis of these comparative costs, which includes consideration of purchased power, conservation and load management. *See also,* Ind. Code § 8-1-8.5-4 requiring the Commission to consider "[o]ther methods for providing reliable, efficient, and economical electric service, including...conservation, load management...."

D. Basis for ongoing State jurisdiction over demand response and continued benefits of traditional regulation. The Commission has explicit statutory authority over a jurisdictional utility's rates, charges, regulations, practices and the provision of electric service. The term "service," as used in the Public Service Commission Act, to be construed "in its broadest and most inclusive sense...." Ind. Code § 8-1-2-1(e). Indiana courts have also recognized that, "[i]nherent in this grant of power [to investigate into the service provided by a utility and rectify any perceived inadequacies] is the implicit power and authority to do that which is necessary to effectuate the regulatory scheme." *South E. Ind. Natural Gas Co. v. Ingram*, 617 N.E.2d 943, 948 (Ind. App. Ct. 1993), citing *Northern Ind. Public Service Co. v. Citizens Action Coalition*, 548 N.E.2d 153, 158 (Ind. 1989), *cert. denied*, 476 U.S. 1137. As the record reflects and as noted above, in Indiana, demand response reductions are an integral part of the provision, and regulated pricing, of retail electric service to customers, as well as in utility and Indiana's short and long term energy and capacity planning.

The Industrial Group asserted that direct customer participation in RTO demand response would have no impact on long-term resource planning. We disagree. It is clear from the record that direct customer participation would introduce a significant degree of additional uncertainty into the evaluation of capacity needs and cost effectiveness in IRP filings with the Commission. Although it may be possible under some circumstances for utilities to anticipate how their load might be impacted by a customer's direct participation in RTO demand response, it is difficult for utilities to adequately fulfill their responsibilities under the Commission's IRP rules when the utilities lack sufficient information or input into such customer participation. It is challenging for utilities to project economic conditions years in advance in an effort to evaluate the cost effectiveness of various resource options for meeting their jurisdictional load obligations, and we do not find it appropriate to introduce greater uncertainty into this process without a demonstration of corresponding benefit. We find that excluding potential cost effective resource solutions from the IRP portfolio is counter to the coherent and comprehensive planning process required under Indiana law.

The record indicates, and a review of MISO and PJM rules corroborate, that Indiana electric utilities' forecasted load to MISO and PJM must include the entire load of the demand response customer with no credit given for past or future reductions by that customer. IMPA Ex. LGM at 5, I&M Ex. 1 at 13, MISO Utilities Ex. R-1 at 4. Thus, the IRP process is harmed because the demand response resources provided by directly participating customers cannot be counted by the local utility toward satisfying its energy or capacity requirements.

Because we regulate and oversee the utility planning process, including all proposals for new supply and demand side resources to meet future needs, as well as provide a forum for review of the reasonableness of the terms and conditions for each of these resources from the perspective of all customers, we do not believe it is appropriate to undermine those responsibilities, nor to put at risk the Indiana electric utilities' ability to rely on demand response as a resource to lower costs and avoid the need to build new generation. We agree with MISO Utilities' witness Caister that direct customer participation in demand response programs at the RTO level would create a mismatch between the obligation to undertake a detailed cost-benefit analysis of demand side resources and the viability of the data necessary for that analysis. We also agree with I&M witness Roush that even though the PJM demand response programs are further developed than their MISO counterparts, PJM utilities may only evaluate demand side resources within their operational control in assessing their resource adequacy obligations.

To the extent the LSEs pursue and administer cost effective demand response envisioned in the IRP rules under traditional Indiana regulation, the resulting customer decrease in demand will reduce the demand for and the cost of wholesale purchased power, adding to the robustness of the competitive wholesale market just as would be the case if the customer directly participated in the RTO demand response program. This structure also preserves the Indiana LSE's ability to rely on demand response as a means of reducing the need for purchased power and new generation, thereby benefiting all of the LSE's retail customers and the state of Indiana as a whole.

We are also mindful of the potential for cost shifting among retail customer classes unless the utility, as the LSE, is ultimately responsible for management of RTO demand response as discussed by Messrs. Caister, Satchwell and Mooney. Direct customer participation in RTO demand response could shift costs to, and create risks for, the utility's remaining customers. The record reflects that direct customer participation in RTO demand response programs could create risks to the cost of providing service. One risk may be the utility having to secure additional capacity to replace that attributable to a customer's direct participation. To the extent a customer directly participates, that curtailable load can no longer be netted from the utility's forecast, so the utility will need to procure more resources than would otherwise be the case at the expense of all customers. Additionally, the Midwest ISO uses the utility daily forecast to help in formulating its load forecast used in the reliability assessment commitment process. If the forecast is overstated, more resources are committed than are actually required, possibly resulting in increased RSG payments. MISO Utilities Ex. 2 at 3-5. In addition, penalties may be incurred if a participating customer fails to shed load when called upon, the utility may also incur additional administrative charges, and the utility will incur fuel and purchased power costs for the load reduction of participating customers despite the fact that the utility does not collect retail revenues from those customers for the level of their load reduction. MISO Utilities Ex. R-1 at 9. Ultimately, individual customers that offer demand response may be winners, but potentially at the cost of other customers.

It is understandable that customers with demand response capability want to maximize that opportunity. However, demand response should not result in uncertainties with respect to a negative impact to the cost of service to non-participating customers. Because direct customer participation in RTO demand response has the ability to directly and significantly affect a utility's provision of electric service, we find that participation in RTO demand response should be done through the retail customer's LSE.[6] Through well designed tariffs or riders, we believe participating customers can obtain significant benefits from demand response, while preserving the utility planning process.

The regulatory obligation of Indiana's electric utilities is to provide reasonably adequate electric service and facilities at the lowest reasonable cost to their Indiana retail customers, including those capable of demand response. As part of this regulatory bargain, it is balanced and symmetrical that those who benefit from this compact, by receiving adequate, reliable and low cost retail service, will in exchange offer their load reduction through the host utility. Accordingly, we find that customer participation in RTO demand response programs or provisions shall be conducted through the customer's electric service provider or LSE. We find that requiring Indiana retail customers to participate in RTO demand response through their LSE will permit the demand response to be incorporated into the IRP process while maintaining Commission oversight of the effect of demand response offerings on participating and non-participating customers.

E. Aggregators of Demand Response. Generally, CSPs serve as an interface or agent between an RTO and an end-use customer for the provision of demand response through the customer's curtailment of electricity. CPower, which was the only CSP that participated throughout this proceeding, enters into obligations with an RTO to provide certain quantities of curtailable load. CPower Ex. TR-1 at 1. CPower then contracts with commercial and industrial retail electric customers who are willing and able to curtail their electricity consumption in exchange for a specified payment. *Id.* CPower aggregates the demand response capabilities of its customers to meet its obligation to the RTO. *Id.* In some cases, CPower also bids a customer's ability to curtail load into the day-ahead or hour-ahead markets. *Id.*

While CPower asserts that Indiana end-use customers should be authorized to participate, directly or through a CSP, in RTO demand response programs or provisions, it also acknowledges the Commission has a legitimate interest in regulating an aggregator's contact with Indiana retail electric customers. *Id.* at 22. CPower also acknowledges that there are cost-shifting issues among the utility, participants and non-participants that are associated with a retail customer's participation in RTO demand response. *Id.* at 15-18.

Consequently, consistent with our finding above that participation in RTO demand response by Indiana end-use customers should occur through their LSE, we find that any aggregation of end-use customer demand response should also occur through the LSE. However, because we agree that CSPs may provide opportunities for small and medium sized commercial and industrial customers that may be underserved by traditional utility demand response programs or may require additional effort for participation in demand response, we strongly encourage the Respondent Utilities to explore opportunities with CSPs which may further enhance participation in demand response by customers of all sizes, classes and

[6] Because we find an electric utility's provision of retail electric service necessarily encompasses demand response activities that may directly and significantly impact a utility's rates, charges and long-term planning, such as participation in RTO demand response programs, we need not address the assertion made by Respondent Utilities and several other parties that direct customer participation in RTO demand response constitutes a resale of electricity and a violation of utility tariffs.

sophistication.

F. Procedural Process for Participation in RTO Demand Response. Having determined that Indiana retail customer participation in RTO demand response programs or provisions should occur through the customer's LSE, we next address the appropriate procedure for considering such customer requests to participate. As noted earlier, we have historically addressed such requests by Indiana retail customers through individually docketed proceedings. However, based on the evidence presented, we recognize that such proceedings could be potentially costly and time consuming, especially for smaller customers.

Both the OUCC and the Industrial Group advocated that the Commission require the development of "generic" tariff offerings, while the Respondent Utilities protested that each utility is different with unique load characteristics, cost structures and tariffs. The Commission recognizes that multiple differences exist among the Respondent Utilities - one of which being the RTO in which they participate - and that any "generic" tariff or rider offerings will need to be tailored to each utility's particular needs and circumstances. Since each RTO has their own demand response programs and provisions with specific associated requirements, we are creating two (2) subdocket proceedings for the purpose of allowing each of the Respondent Utilities to file tariff(s) or rider(s), for Commission approval, providing for the participation of retail customers in RTO demand response programs or provisions through the LSE.[7]

Respondent Utilities that are members of PJM shall file their respective tariff(s) or rider(s) in the first subdocket, Cause No. 43566 PJM. Each utility filing in the subdocket will be assigned a specific number based on the order in which the filing was received by the Commission. For example, the first Respondent Utility to file its tariff(s) or rider(s) will be assigned Cause No. 43566 PJM 1, the second Respondent Utility to file its tariff(s) or rider(s) will be assigned Cause No. 43566 PJM 2, and so on. Respondent Utilities that are members of the Midwest ISO shall file their respective tariff(s) or rider(s) in the second subdocket proceeding, Cause No. 43566 MISO, and will be assigned a specific subdocket number in a similar fashion.

Respondent Utilities shall file their respective tariff(s) or rider(s) in the correct subdocket within ninety (90) days of the Commission Order in this Cause. In developing the tariff(s) or rider(s), Respondent Utilities are encouraged to work collaboratively with the OUCC, the parties to this proceeding, and any other interested parties. To assist in establishing an appropriate framework for the development and filing of Respondent Utilities' tariff(s) or rider(s), a Prehearing and Technical Conference will be convened in both subdockets, Cause Nos. 43566 PJM and 43566 MISO, on September 7 and 8, 2010. The first day will be to address general issues pertaining to the development of the tariff(s) or rider(s) and to determine a procedural schedule, to the extent necessary, that allows for Commission approval of each tariff or rider by the start of the 2011 registration deadline for participation in an RTO demand response program or provision. The second day will be broken into two sessions; the morning session will be to

[7] Until the LSE has a Commission approved tariff or rider for the participation of retail customers in RTO demand response programs or provisions, the Commission will continue to consider any petitions of retail customers to participate in such programs as set forth in the Commission's Order on Requests for Interim Relief issued on February 24, 2009 in this Cause.

address PJM specific issues and the afternoon session will be to address MISO specific issues. Each Respondent Utility shall come prepared to the Technical Conference to identify and discuss the factors to be addressed and considered in developing the tariff(s) or rider(s).

G. Reporting Requirements.

1. Annual Reporting Requirements. In an effort to monitor customer interest and participation in RTO demand response programs, the Commission finds that Respondent Utilities shall file an annual report in this Cause beginning with calendar year 2011. Such annual report shall be filed by March 15 following the end of the calendar year and shall include, at a minimum, the following information for the calendar year being reported:

(1) The number and size of customers participating in the utility's RTO demand response tariff(s) or rider(s);

(2) The particular RTO demand response program or provision in which customers are participating and the amount of load participating;

(3) A description of the efforts being made to encourage participation by small and medium sized customers in the utility RTO demand response tariff(s) or rider(s);

(4) Any agreements reached, or being considered, with any CSP or other entity for the purpose of aggregating customers for participation in RTO demand response programs or provisions;

(5) Information on how the RTO demand response tariff(s) or rider(s) were used by the utility in meeting its service obligations, which RTO products the demand response capabilities made possible by the tariff(s) or rider(s) were employed by the utility, when the demand response resources were used by the RTO and the circumstances existing at that time for both the utility and the RTO.

2. Other Reporting. During a July 9, 2009 Attorneys Conference convened in this Cause, the Commission learned that PJM had registered 59 Indiana sites to participate in PJM's demand response programs or provisions for 2009. As the vast majority of these sites had not received Commission approval to participate, such registration and participation was conducted in contravention of the Commission's February 25, 2009 Order on Requests for Interim Relief, which prohibited Indiana end-use customers from directly participating in RTO demand response without prior Commission approval.

As set forth above, the Commission's Order in this Cause continues to prohibit Indiana end-use customers from directly participating in RTO demand response without prior Commission approval and establishes a procedure for authorizing such customer participation only through the customer's electric utility or LSE to ensure the costs and the benefits of demand response participation are appropriately allocated and received by the utility and Indiana customers. In an effort ensure this objective is accomplished, the Commission finds it appropriate to monitor compliance with this Order and to ensure the Commission is timely aware of any registration that may be made by an Indiana end-use customer seeking to directly participate in an RTO demand response program or provision. Therefore, Respondent Utilities shall file a notice with the Commission under this Cause within forty-eight (48) hours of receiving notice from the RTO that an end-use customer has registered to directly participate in an RTO demand response program or provision.

5. **Motions.** On February 17, 2010, CPower filed a Motion for Interim Authority seeking the issuance of an order granting CPower interim authority for its Indiana customers to participate in PJM's demand response programs from June 1, 2010 to May 31, 2011. On that same day, the Industrial Group filed a Response also requesting interim authority for its members to participate in PJM's demand response programs.

On February 23, 2010, Energy Curtailment Specialists, Inc. ("ECS") filed its Petition to Intervene and Motion for Interim Authority to Participate in PJM's Demand Response Programs. On February 24, 2010, Atlas Foundry Co., Inc. ("Atlas") also filed a Petition to Intervene and for Expedited Approval to Participate in PJM Load Response Programs. On February 26, 2010, EnerNOC, Inc. ("EnerNOC") filed its Motion for Interim Authority to participate in PJM's demand response programs and request for the Commission to take administrative notice of a January 19, 2010 FERC Order, or in the alternative to reopen the record to take additional evidence.

On March 1, 2010, I&M filed its Objection to ECS's Petition to Intervene and its Response to the various motions for interim authority to participate in PJM's demand response programs. On March 3, 2010, I&M filed its Objection and Response to Atlas' Petition to Intervene and for Expedited Approval. On March 8, 2010, I&M filed its Response to EnerNOC's Motion.

On March 5, 2010, ECS filed its Reply to I&M's Response and Objection. On March 8, 2010, CPower filed its Reply and Concurrence in ECS' Reply.

Based on the findings herein, the Commission denies all Motions for Interim Authority and Petitions to Intervene. To the extent that Atlas, ECS or any other entity desires to intervene in the subdocket proceedings, they may file petition to do so in either, or both, subdockets. Finally, as the Commission did not find it necessary to reach the issue of whether demand response involves a sale for resale, we deny EnerNOC's Motion to take administrative notice or in the alternative to reopen the record.

6. **Conclusion.** The Commission supports FERC's efforts to increase demand response at the wholesale level and believes that RTO demand response programs and provisions must work in tandem with, and not in contravention of, Indiana's utility regulatory framework. The record demonstrates that Indiana has a history of encouraging the use of demand response resources. The Respondent Utilities have tariffs, special contracts and programs designed to foster customer demand response and are continuing to explore additional opportunities to provide demand response offerings. These offerings recognize the utility's need for cost effective demand response resources and also ensure that the demand response for which the customer is being compensated for under the tariff or rider is actually achieved. Because demand response is part of Indiana's IRP process and a required consideration in determining the necessity of any new generation, use of demand response is consistent with the objective of

meeting the statutory obligation for adequate and reliable electric service through diverse, yet cost-effective resources. Although direct customer participation in RTO demand response programs may make sense for customers in competitive retail and wholesale markets, we lack the evidence necessary to determine this structure would work effectively for customers in Indiana's traditionally regulated retail jurisdiction.

We find the benefits of demand response are best captured by permitting Indiana retail customers to participate in RTO demand response programs or provisions through their LSE. Among other things, this structure permits load reduction to be aligned with, and tailored to, Indiana peaks or strategic regulatory goals and provides for Commission oversight. Because future expenditures on, and the impact of, demand response would be reflected in rates, the Commission has a statutory obligation to oversee those demand response programs and provisions that have sufficient capability to impact a utility's electric service. Accordingly, we find that Indiana end-use customers, unless otherwise authorized by the Commission, should not be enrolled or otherwise participate in RTO demand response programs or provisions directly or through CSPs (or other aggregators).

We further find that the Respondent Utilities should continue to provide retail customers opportunities to participate in LSE-provided demand response programs and should expand such offerings to include participation in RTO demand response programs or provisions pursuant to appropriate utility tariffs or riders in accordance with the findings herein. We further find that the Respondent Utilities should investigate whether the provision of cost-effective demand response offerings could be enhanced by working with an aggregator, but note that any such agreements should be presented to the Commission for approval.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Indiana end-use customers shall not be enrolled or otherwise participate in RTO demand response programs directly or through curtailment service providers or other aggregators.

2. In accordance with Finding Paragraph 4.F., Respondent Utilities that are members of PJM shall file, with the Commission for approval in Cause No. 43566 PJM, tariffs or riders authorizing the participation of its retail customers in PJM demand response programs through the Respondent Utility within ninety (90) days of the date of this Order.

3. In accordance with Finding Paragraph 4.F., Respondent Utilities that are members of the Midwest ISO shall file, with the Commission for approval in Cause No. 43566 MISO, tariffs or riders authorizing the participation of its retail customers in Midwest ISO demand response programs through the Respondent Utility within ninety (90) days of the date of this Order.

4. A Prehearing and Technical Conference in Cause Nos. 43566 PJM and 43566 MISO is scheduled for September 7 and 8, commencing at 9:30 a.m. in Room 222, 101 West Washington Street, Indianapolis, Indiana.

5. Respondent Utilities shall file in this Cause an annual report in accordance with Finding Paragraph 4.G.1.

6. Respondent Utilities shall notify the Commission with a filing under this Cause when it receives notice of any registration by an end-use customer for direct participation in an RTO demand response program in accordance with Finding Paragraph 4.G.2.

7. This Order shall be effective on and after the date of its approval.

HARDY, ATTERHOLT, LANDIS, AND ZIEGNER CONCUR; MAYS NOT PARTICIPATING:

APPROVED: JUL 28 2010

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe,
Secretary to the Commission