UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER17-284-000**

MOTION TO INTERVENE AND PROTEST OF THE RETAIL ENERGY SUPPLY ASSOCIATION

Pursuant to Rules 211 and 214 and of the Federal Energy Regulatory Commission's ("Commission's") Rules of Practice and Procedure, 18 C.F.R. §§ 385.211 and 385.214, the Retail Energy Supply Association ("RESA")[1] hereby files this Motion to Intervene and Protest in the above-referenced proceeding where Midcontinent Independent System Operator, Inc. ("MISO") seeks to establish a Forward Reserve Auction ("FRA") to ensure resource adequacy in areas where there is retail competition – referred to in the filing as Competitive Retail Areas ("CRAs"). MISO's Competitive Retail Solution ("CRS") contains procedures to permit opt-out of the program. RESA supports competitive markets, including competitive capacity markets. However, RESA objects to the opt-out provisions that would eviscerate retail access at the unilateral option of a state commission in states that promote retail access. RESA submits that certain opt-out provisions must be rejected and, if not rejected outright, conditioned. In support of this Motion to Intervene and Protest, RESA submits as follows:

1 The comments expressed in this filing represent the position of the Retail Energy Supply Association (RESA) as an organization but may not represent the views of any particular member of the Association. Founded in 1990, RESA is a broad and diverse group of more than twenty retail energy suppliers dedicated to promoting efficient, sustainable and customer-oriented competitive retail energy markets. RESA members operate throughout the United States delivering value-added electricity and natural gas service at retail to residential, commercial and industrial energy customers. More information on RESA can be found at www.resausa.org.

I.
MOTION TO INTERVENE

A. Correspondence and Communications

Correspondence and communications regarding this matter should be addressed to the following person(s), and the same should also be designated for service on the Commission's official service list for this proceeding:

Elizabeth W. Whittle
Nixon Peabody LLP
799 Ninth Street, N.W.
Suite 500
Washington, DC 20001
202-585-8338
202-585-8080 (fax)
ewhittle@nixonpeabody.com

Joseph E. Oliker
Regulatory Counsel
IGS Energy
6100 Emerald Parkway
Dublin, OH 43016
614-659-5069
joliker@igsenergy.com

B. RESA

RESA is a non-profit trade association of independent corporations that are involved in the competitive supply of electricity. RESA and its members are actively involved in retail electricity markets throughout the United States, including retail markets in each of the Commission-approved RTO/ISOs. Many of RESA's members are active in MISO markets and will be subject to the new FRA program.

C. Motion to Intervene

On November 1, 2016, MISO made its filing to implement the FRA. Specifically, MISO proposes a new Module to its Tariff – Module E-3. Module E-3 will apply to CRAs in the MISO footprint, which currently consists of Local Resource Zones 4 and 7. MISO seeks to implement the capacity program prior to the 2018/2019 Planning Year.

As active participants in MISO markets, in particular, LRZs 4 and 7, RESA has an interest in this proceeding that cannot be represented by any other party. RESA respectfully requests that its Motion to Intervene be granted.

II.
PROTEST

A. Background

In its November 1, 2016 filing, MISO seeks to implement a FRA to ensure that resource adequacy is supported in regions in MISO where retail choice is allowed. MISO refers to its new program as a Competitive Retail Solution and it is based on the forward capacity markets in PJM Interconnection, L.L.C. ("PJM") and ISO New England, Inc. ("ISO-NE"). Under the program, the prices suppliers will be paid for capacity they sell in an FRA will be set based upon a downward-sloping demand curve. The program will apply currently to LRZs 4 and 7, where retail customers may choose their electric supplier. According to MISO, the FRA is needed in this area because the States do not have legal authority to mandate resource adequacy through state-mandated generation construction to address long-term resource adequacy. In CRAs, market participants rely on price signals to incent the investment in additional resources, including generation. This three year forward market is similar to that used in PJM and ISO-NE and is a market solution for competitive markets.

MISO includes a proposed "bright line" criteria to make it clear to whom the program applies. Under the proposal, "if an LSE has a material level of Competitive Retail Demand and the LSE is not subject to any jurisdictionally-required long-term resource adequacy planning processes, the LSE's Competitive Retail Demand is subject to the CRS resource adequacy requirements". Filing Letter at 22.

With respect to the-opt out process, MISO proposes two alternatives for opting out of the

CRS program. One is at the election of the LSE -- the LSE may procure capacity by submitting a Forward Fixed Resource Adequacy Plan ("FFRAP"). Under the FFRAP, the LSE demonstrates that it can provide sufficient Zonal Resource Credits to meet its Planning Reserve Margin Requirements. Filing Letter at 23. An LSE that submits a FFRAP may not procure additional capacity in the FRA. RESA does not object to retail LSEs opting out in whole or in part of the FRA to the extent that they are not deemed pivotal suppliers. But RESA objects to pivotal generation suppliers within CRAs submitting a Fixed Resource Adequacy Plan ("FRAP") or FFRAP, given that this practice would insulate the large majority of generation resources within the region from participating in FRAs – potentially creating scarcity and volatility in the auctions – to the detriment of transparency, forward price signals, and market confidence. By increasing the amount of resources subject to the FRAs, the Commission can place generation capacity within CRAs on even footing and provide appropriate forward price signals needed to promote investment in generation and resource adequacy.

The second alternative is objectionable and referred to as the Prevailing State Compensation Mechanism ("PSCM"). Under the PCSM, if the Relevant Electric Retail Regulatory Authority ("RERRA") has jurisdiction over LSEs, including retail LSEs, the RERRA may elect to take responsibility for long-term resource adequacy needs of its retail consumers by ensuring all Competitive Retail Demand will be covered through a FFRAP or FRAP." The RERRA must notify MISO as to who is responsible for the applicable obligation and the rate. The RERRA would then exercise control over the wholesale capacity procurement process.

MISO asserts without evidence, that the PSCM "provision respects State and federal jurisdictional authority relating to wholesale and retail supply and is consistent with Commission precedent." Filing Letter at 24. According to MISO, the provision it sponsors is similar to that approved in PJM. *Id*. Any settlements under the PSCM will occur outside of the FRA market settlement procedures and the charges and settlements will be "administered" by the RERRA.

RESA supports competitive markets, including competitive procurement of resources necessary to meet resource adequacy requirements and mechanisms that permit LSEs in retail access states to meet resource adequacy obligations. RESA supports MISO's efforts to create a competitive capacity markets in LRZs 4 and 7. However, in order to have a competitive capacity market, there must be sufficient capacity in the market. Thus, the Commission must reject the PSCM. The opt-out provision is unjust and unreasonable and the PSCM impermissibly interferes with the Commission's jurisdiction. The PSCM was a last-minute addition to the MISO Tariff and was not the result of stakeholder input and discussion. It has not been shown to be just and reasonable; has not been justified at all as necessary for the program. In short, MISO has not met its burden of proof to support the PSCM provisions and Miso's Tariff provision proposing the PSCM must, therefore be rejected. In the alternative, should the Commission accept the concept of a PSCM, it must condition the mechanism by expressly requiring an affirmative showing that the use of the PSCM is expressly authorized by state statute by giving the state jurisdiction to order LSEs to procure and construct generation for reliability or otherwise restrict competitive retail supplier participation in competitive capacity markets.

B. The PSCM Violates the Federal Power Act and Infringes on the Commission's Exclusive Jurisdiction

MISO asserts in its Filing Letter (at 11) that the Commission recognizes state jurisdiction over resource adequacy. However, MISO's statement is not as definitive as it appears. The PSCM does not pass muster and must be rejected as violative of the FPA for intruding on the Commission's exclusive jurisdiction. In the order cited by MISO for its assertion that the

Commission accepts state jurisdiction over resource adequacy, *Midwest Independent Transmission System Operator, Inc.*, 122 FERC ¶ 61,283 (2008), the Commission expressly noted its jurisdiction under the Federal Power Act ("FPA") over wholesale capacity prices. Specifically, the Commission stated at P.52,

> . . . the role for state authorities cannot undercut this Commission's authority to review resource adequacy and reserve margins that affect matters within our jurisdiction, i.e., provisions that affect our authority under sections 201, 205, and 206 of the FPA to ensure that the provisions of the tariff will result in just and reasonable and not unduly discriminatory or preferential rates.

In fact, the Commission addressed the state/federal jurisdictional issue in orders involving the establishment of the RPM in PJM. MISO's proposal is allegedly based on PJM's program. The Commission stated:

> While we recognize the traditional role of state and local entities in regulating resource adequacy, we are also aware of our responsibilities under the FPA to ensure that adequate service is provided, and that responsibilities under the FPA to ensure that adequate service is provided, and that wholesale rates are just and reasonable. We will defer to state and local entities' decisions when possible on resource adequacy matters, but in doing so we will not shirk our congressionally-mandated responsibilities. We find that resource adequacy can have a significant effect on wholesale rates and service and, therefore, is subject to Commission jurisdiction.

PJM Interconnection, L.L.C., 119 FERC ¶ 61,338 at P.40 (2006); *reh'g denied*, 121 FERC ¶ 61,173 (2007); *aff'd sub nom. Pub. Serv. Elect. & Gas Co. v. FERC*, D.C. Cir. No. 07-1336 (Mar. 17, 1001). Similarly, the Commission's asserted jurisdiction over resource adequacy in ISO-NE was affirmed by the courts. *See*, *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. (2009)), *cert. denied*, 130 S. Ct. 1051 (2010).

The Commission's jurisdiction over wholesale rates, including capacity prices has also been affirmed by the U.S. Supreme Court in *Hughes v. Talen Energy Marketing*, 578 U.S. ___

(2016). In rejecting proposed Section 68.3 to the resource adequacy proposal that was the subject of the above-referenced MISO order, in particular, the requirement addressing the ability of state commissions to set reserve margins, the Commission noted that the Commission's jurisdiction carries over to many features of a program that affect a rate, including capacity costs. For example, the Commission's jurisdiction also extends to deficiency charges assessed by NEPOOL when a participant's prescribed level of generating capacity falls below a set level. *Id*. at P.61. Citing *Municipalities of Groton v. FERC,* 587 F.2d 1296 at 1302, (D.C. Cir. 1978), the Commission found:

> [i]t is sufficient for jurisdictional purposes that the deficiency charge affects the fee that a participant pays for power and reserve service, irrespective of the objective underlying that charge. This is well within the Commission's authority as delineated in other court opinions.

The U.S. Supreme Court in *Hughes* confirmed the Commission's jurisdiction over state actions which "affect" the wholesale rate. In *Hughes,* the U.S. Supreme Court determined that a State's efforts to provide financial support to generators (with the alleged goal to "incent" them to construct in Maryland) by ordering utilities to contract with a generator at a rate that was not the PJM competitive market capacity rate, was in violation of the FPA because the State's actions affected impermissibly a wholesale rate. As the Court stated (slip op at 26), citing *FERC v. EPSA*, 577 U.S. ___, "[t]he FPA leaves no room either for direct state regulation of the prices of interstate wholesales or for regulation that would indirectly achieve the same result." [slip op.at 12]. It is impermissible for a State to "interfere with FERC's authority by disregarding interstate wholesale rates FERC has deemed just and reasonable, even when States exercise their traditional authority over retail rates, or … in-state generation." *FERC v. EPSA*, Slip op at 14.

As in *Hughes*, and the long line of precedent supporting the Court's decision, an RERRA that usurps the right of a retail LSE in a state that allows retail competition by setting its own rate for capacity is an action that violates the FPA. The stated reason for MISO' filing is that the CRS will apply "where no integrated resource adequacy planning processes exist, potential capacity shortfalls are far more likely to occur than in traditionally regulated states". Filing Letter at 4. MISO goes on to state that MISO is "proposing a new structure for jurisdictions that have implemented retail choice and in which no State or local authority has jurisdiction over long-term resource planning." Filing Letter at 5.

In Michigan, for example, State law allows retail LSEs to supply up to ten (10) percent of load in the state. Michigan is one of the LRZs that will be subject to the new CRS program because no state or local authority has jurisdiction over long-term resource planning. Under the Tariff as proposed, the state, which MISO has asserted does not have jurisdiction over resource adequacy for LRZs 4 and 7, could "elect" to remove the Competitive Retail Demand from the FRA. The state would, at that point, be usurping the Commission's jurisdiction over wholesale rates in violation of the FPA. MISO's Tariff language, as drafted, would not require any showing by the applicable state to show that it has the legislative authority over resource adequacy for retail LSEs. MISO essentially proposes to grant to the RERRA Federal jurisdiction over resource adequacy.

C. The Proposed Tariff Language Would Impermissibly Transfer Commission Jurisdictional Activities to the State

MISO proposes to define "Prevailing State Compensation Mechanism" as "an alternative method for demonstrating long-term resource adequacy, elected by a RERRA that removes Competitive Retail Demand from the Forward Resource Auction." *See* draft Definitions – P, 42.0.0. In proposed Section 69A.12.1.2, a "RERRA may elect a Prevailing State Compensation Mechanism for entities over which it has jurisdictional authority." All an RERRA must do is "notify the Transmission Provider" of its election of a PSCM. In short, with one notification to MISO and without any showing that the RERRA has not only "jurisdiction" over the LSE, but that it has the jurisdiction to take the obligation from the LSE to supply capacity and other services to retail customers under state law, the RERRA may eviscerate the competitive wholesale market for capacity and replace the wholesale rate with its own rate.

A state commission may have "jurisdictional authority" over a retail supplier for purposes of registration and reporting and other ministerial requirements to ensure that the public is protected. That authority in no way affects a State's jurisdiction to encompass the field in resource adequacy. In fact, the whole purpose of the MISO's filing to implement a resource adequacy program in LRZs 4 and 7 was an identified concern is that there is a "gap" in resource adequacy that is necessary because the state commissions do not have authority over ensuring resource adequacy in those LRZs. *See* MISO's Issue Statement at p.1[2] and Filing Letter at 5. LSEs operating in LRZs 4 and 7 will, if the proposal is accepted, have a resource adequacy obligation and will procure capacity in the wholesale market.

The tariff language proposed by MISO would provide the state commission as RERRA with a unilateral option to force LSEs to forego the competitive market without any showing that it has the legal authority to do so (not just "jurisdictional authority" over the LSE) and force the LSEs to forego the competitive market to the detriment of the market and its customers. MISO and the stakeholders identified an issue due to the fact that there was no state-imposed obligation. Including this language gives the state commission an option to do just what it cannot do directly. An entity cannot do indirectly what it cannot do directly. *Public Utilities Commission of State of California v. FERC,* 143 F.3d 610, 615 (DC Cir. 1998); *Altamount Gas*

[2] The Issues Statement was attached to MISO's Filing as Tab H.

Transmissions Co. v. FERC, 92 F.3d 1239, 1244 (DC Cir. 1996); *Carmell v. Texas,* 529 U.S. 513, 541 (2000). In addition, allowing a unilateral option to a state commission to step in and eviscerate the very program MISO seeks to create would violate long-standing precedent that the Commission cannot delegate to another matters within its sole and exclusive jurisdiction. See *City of Colton v. Southern California Edison Co.,* 26 F.P.C. 223, 236 (1961); *FPC v Southern California Edison Co.* 376 US 205, 209 (1964). Resource adequacy in this instance is within the Commission's sole and exclusive jurisdiction and cannot be delegated to the state on little more than a whim and, more perniciously, through a desire to eliminate competition in favor of the vertically integrated utilities that they regulate. The PSCM must be rejected.

D. The Existence of a Similar Provision in the PJM Tariff is Not Support for MISO's Provision

MISO attempts to support the PSCM by asserting that a similar mechanism exists in the PJM Tariff. However, the circumstances pursuant to which PJM's provision was devised and this one are different. The provisions are different as well. The "similar" language in the PJM tariff was included in a basket of significant tariff changes resulting from a global settlement that created the PJM's forward capacity market, *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006); *order on reh'g*, 119 FERC ¶ 61,338 (2006); *reh'g denied*, 121 FERC ¶ 61,173 (2007); *aff'd sub nom. Pub. Serv. Elect. & Gas Co. v. FERC*, D.C. Cir. No. 07-1336 (Mar. 17, 1001). The language was the result of the give and take in a complex settlement process that involved 25 days of discussions, 150 entities and one settlement judge, *PJM*, 117 FERC at P.24 The PJM RPM settlement expressly contains language, consistent with Rule 602 that provides that the settlement cannot be used as a precedent in any other proceeding. See PJM Settlement, filed on September 29, 2006 in Docket No. ER05-1410, at P.46: "[t]his Settlement Agreement establishes no principles and no precedent with respect to any issue in this proceeding." Thus, the fact that a similar provision may exist in PJM, devised as part of a complex Settlement, cannot be used to support MISO's filing, where it bears the burden of the proof and the obligation, under FPA Section 205, to show that a filing is just and reasonable.

Here, MISO did not engage stakeholders at all in developing the PSCM mechanism. In fact, this provision was inserted at the end of the stakeholder process and developed outside the confines of the stakeholder process. It was presented as a fait accompli and retained over the objections of a number of stakeholders.

In addition, the PJM state compensation mechanism has been used in the PJM region where the utilities do not participate in the forward capacity market. These utilities in PJM are FRR Entities – they do not participate in the forward capacity auctions but handle capacity procurement bi-laterally and outside the competitive markets. Here, the CSR has been developed because LSEs are not part of the investor owned utility's planning responsibility. LSEs arrange for their own capacity and that is the concern for MISO – that there is no mechanism in place to ensure resource adequacy in these LRZs. Simply put, the PSCM is not the result of a settlement and is not the result of the give and take that takes place in the settlement process. The PSCM was not included in the Retail Choice Issues Statement, issued by MISO Staff in October 2015.

In PJM, the Michigan Public Service Commission ("MPSC"), which regulates the investor-owned utilities Consumers Energy and Detroit Energy, has abused the "similar" PJM provision to shut down competition in the Indiana Michigan Power Company ("I&M") service area,[3] creating an impermissible price squeeze in the process.

[3] I&M is an affiliate of AEP, and its operating companies are FRR Entities in PJM.

On May 24, 2012, the MPSC issued for I&M an Order Initiating Proceeding and Notice of Hearing in Docket U-17302. The MPSC required I&M to "file a cost of service based proposal for the creation by the MPSC of a state compensation mechanism for Alternative Electric Suppliers ("AES"). The MPSC used the PJM Tariff, not its organic statutory authority to commence the proceeding. Also, I&M was an FRR Entity and under the PJM Tariff, responsible for planning for its load in its service area. At the conclusion of the proceeding and as an FRR Entity, the MPSC established a capacity rate for AESs at the retail/embedded capacity price, which included a component of I&M's energy costs, despite the fact that AESs did not need energy from I&M. In addition, AESs did not receive a credit for I&M's off system sales, like its captive retail customers did. The result of the rate imposed by the MPSC resulted in AES customer losses of 15-35%, essentially eliminating competition in the I&M service area.[4] This is a typical and textbook price squeeze, See *FPC v. Conway*, 426 US 271,279 (1976).

RESA believes that the MPSC will eliminate electric choice in the rest of Michigan using the same tactic. The MPSC will allege that the authority to establish its own embedded cost capacity rate is given to the MPSC by the MISO Tariff, despite the fact that it does not possess the statutory authority to accomplish the same thing itself (or else it would have done it by now). The Commission should not allow the MPSC use the Federal Power Act to do indirectly what it cannot do directly. The Commission must reject the PSCM.

E. In the Alternative, Should the Commission Accept the Concept of a Unilateral Right of a State to Require Retail LSEs to Exit the Competitive Market, the Commission Must Require MISO to Modify the Tariff to Require a Showing from the RERRA that Such Action is Within Its Jurisdiction

[4] *See In the matter, on the Commission's own motion, to initiate a proceeding to establish a state compensation mechanism for alternative electric supplier capacity in INDIANA MICHIGAN POWER COMPANY'S Michigan service territory,* Case No. U-17032, Brief of Energy Michigan, Inc. at 2, attached hereto as Exhibit A.

Should the Commission determine that, despite the jurisdictional infirmities, it will accept the RERRA opt out option, the Commission must require MISO to modify the language to require that the RERRA show, by an opinion of the Attorney General or equivalent authority, that the exercise of the right is within the statutory authority of the applicable state. The Commission must not accept the vague language that only requires the RERRA to have jurisdiction over the LSE – the RERRA must show that it has the statutory authority to exercise the right to limit the rights of LSEs. MISO has presented circular reasoning for the PSCM – it says that the FRA is needed because the RERRA would not otherwise have jurisdiction over resource adequacy and then grants the RERRA that very authority using a FPA-based Tariff. Before exercising this right, the State must have it by organic state statute and prove that the right exists.

MISO has not shown that the proposed Tariff provisions governing the PSCM is just and reasonable as it is required to do under FPA Section 205. MISO has filed no support for the provision, other than general statements in the Filing Letter and Testimony of Jeffrey Bladen (at 18-19). Mr. Bladen in his testimony notes the unilateral nature of the right of a RERRA to opt Competitive Retail Demand out of the FRA. His support is scant. Mr. Bladen notes that a mechanism exists in PJM and that it is used in Ohio and Michigan and he acknowledges the unilateral nature of the option that may be exercised by an RERRA respecting Competitive Retail Demand within its jurisdictional authority. He suggests that there is an alternative to the PSCM that would give LSEs the option to opt out of the PSCM. However, that option is not a market-based solution, but is an obligation to obtain capacity bi-laterally. Mr. Bladen states (at 18, l.21 – 19, l.3) that:

> competitive retail providers will still have the ability to opt their retail choice demand out of paying the PSCM rate through demonstrating their ability to meet

> such demand's resource adequacy needs. That demonstration is accomplished through submission of a FFRAP in the CRS process. When a competitive retail provider submits a FFRAP in a jurisdiction that has elected the PSCM that LSE will not be charged the PSCM rate, having demonstrated compliance with the FFRAP instead.

However, submitting a FFRAP is yet another alternative to the market-based solution and requires bi-lateral arrangements. This provision could be used by the incumbent utilities, Detroit Edison and Consumers, to reduce the liquidity of the capacity auction and could create unduly discriminatory limitations by not providing capacity resources to the new FRA. The incumbent utilities recover their costs via the MPSC and could be insulated from the competitive market.

MISO's showing is deficient. The exception to the competitive FRA will swallow the entire effort – if Michigan does what it did with I&M, there will only be one area to which this program applies. MISO cannot just rely on the mechanism in PJM to support their program and must show that this potential state intrusion on the Commission's jurisdiction is just and reasonable (which it is not).

III.
CONCLUSION

The PSCM has not been shown to be just and reasonable and is, in fact unjust and unreasonable. The PSCM would violate the Federal Power Act and result in an impermissible deferral of the Commission's jurisdiction over wholesale rates to the state. This is particularly true when the state does not have its own jurisdiction over resource adequacy. The fact that a similar provision exists in PJM is irrelevant – that provision was the result of a complex settlement process – there is no settlement here. In fact, there was very little stakeholder discussion of the provision and, when it was brought up, MISO refused to make any changes to it. The PSCM must be rejected. In the alternative, should the Commission accept the provision, the Commission must require MISO to require evidence that the relevant RERRA has the requisite authority under its state statute over resource adequacy, including the authority to order LSEs to construct generation in order to meet resource adequacy requirements. Finally, RESA does not object to retail LSEs opting out in whole or in part of the FRA to the extent that they are not deemed pivotal suppliers. But RESA objects to pivotal generation suppliers within CRAs submitting a FRAP or FFRAP and insulating themselves from the new FRA and reducing liquidity in the new market.

WHEREFORE, RESA respectfully requests that its Motion to Intervene be granted and Protest considered by the Commission.

Respectfully submitted,

/s/Elizabeth W. Whittle
Elizabeth W. Whittle
Counsel to
The Retail Energy Supply Association

Of Counsel:

Nixon Peabody, LLP
799 Ninth Street, N.W.
Suite 500
Washington, DC 20001
202-585-8338
202-585-8080
ewhittle@nixonpeabody.com

Dated: December 14, 2016

EXHIBIT A

VARNUM
ATTORNEYS AT LAW

201 N. Washington Square • Suite 810
Lansing, Michigan 48933
Telephone 517 / 482-6237 • Fax 517 / 482-6937 • www.varnumlaw.com

Eric J. Schneidewind ejschneidewind@varnumlaw.com

July 16, 2012

Ms. Mary Jo Kunkle
Michigan Public Service Commission
6545 Mercantile Way
P.O. Box 30221
Lansing, MI 48909

Re: Case No. U-17032

Dear Ms. Kunkle:

Attached for paperless electronic filing are Testimony and Exhibits of Alexander J. Zakem and Roy Boston on Behalf of Energy Michigan, Inc. Also attached is a Proof of Service indicating service on counsel.

Thank you for your assistance in this matter.

Very truly yours,

VARNUM, LLP

Eric J. Schneidewind

EJS/mrr

cc: ALJ
parties

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion to initiate a proceeding to establish a state compensation mechanism for alternative electric supplier capacity in INDIANA MICHIGAN POWER COMPANY'S Michigan service territory.	))))))	Case No. U-17032

DIRECT TESTIMONY

OF

ALEXANDER J. ZAKEM

ON BEHALF OF

ENERGY MICHIGAN

DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Alexander J. Zakem and my business address is 46180 Concord, Plymouth, Michigan 48170.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Energy Michigan.

Q. Please state your professional experience.

A. Since January of 2004 I have been an independent consultant providing services to Integrys Energy Services, Inc., Quest Energy (a wholly-owned affiliate of Integrys Energy Services), and other clients. Integrys Energy Services is a member of Energy Michigan.

From March 2002 to December 2003, I was Vice President of Operations for Quest. My responsibilities included the overall direction and management of Quest's power supply to its retail customers. This included power supply planning, development of customized products, negotiation with suppliers, planning and acquiring transmission rights, and scheduling and delivery of power. It also included managing risk with respect to market price movements and variation of customer loads.

Prior to retiring from Detroit Edison in 2001, from 1998 I was the Director of Power Sourcing and Reliability, responsible for purchases and sales of power for mid-term and long-term periods, planning for generation capacity and purchase power needs, strategy for and acquisition of transmission rights, and related support for regulatory proceedings.

Additional experience, qualifications, and publications are contained in Exhibit EM-1 (AJZ-1).

Q. Have you testified as an expert witness in prior proceedings?

A. Yes. I have testified as an expert witness in several proceedings before the Michigan Public Service Commission ("Commission"), on topics such as standby rates, retail rates and regulations, recovery and allocation of costs and revenues, and the effects of rate restructuring. I have also testified before the Federal Energy Regulatory Commission. Case citations are in Exhibit EM-1 (AJZ-1).

Q. What is the purpose of your Testimony?

A. Indiana Michigan Power Company ("I&M") has proposed a "cost of service based capacity pricing proposal" to charge Electric Choice customers for the use of I&M's capacity, based on a cost of service study.

The purposes of my Testimony are:

I. to explain the deficiencies of I&M's proposal,

II. to offer an alternative compensation method that is simpler and that works better under competition, and

III. to separate the issue at hand – transfer price of capacity in a competitive market – from broader issues of recovery of revenues or fixed costs by the utility while retaining the ability of the utility to recover its authorized revenues.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit EM-1 (AJZ-1) Qualifications.

I. Deficiencies of I&M's Proposal

Q. What is the underlying cause of the deficiencies in I&M's proposal?

I&M applies a retail cost-of-service method based on allocation of fixed costs to develop a charge to collect money from retail customers. However, the objective of this proceeding is fair and reasonable compensation to I&M from another supplier for a wholesale service provided to the other supplier. I&M uses a tool not designed for the objective and applies it without sufficient adaptation. Consequently, the resulting solution proposed by I&M does not fit the problem.

Q. What is the result of the deficiencies in I&M's proposal?

A. I&M's proposal does not answer the central question, which is how should an Alternative Electric Supplier (AES) compensate I&M for capacity pledged to the PJM

Regional Transmission Organization (RTO) when a customer switches from I&M to the AES.

Q. What are the specific deficiencies?

I&M merely goes through a formalistic cost-of-service study, assumes erroneously that it provides capacity service *directly* to retail Electric Choice customers, assumes erroneously that *only* I&M capacity is used by all I&M's distribution customers, fails to correctly apply cost-of-service principles, does not give fair credits for off-system sales to Electric Choice customers and for other savings created by Electric Choice, and allocates unreasonable and excessive amounts of power plant costs under the caption of capacity costs.

Q. Would you explain these deficiencies?

A. Yes. First, for ease of understanding, I want to give some brief background information on capacity, cost allocations, and use and dispatch of generation resources in a Regional Transmission Organization (RTO) such as PJM.

Q. What is "capacity"?

A. In the electric industry, capacity is the ability to convert energy in one form (fuel) to energy in another form (electric energy) at a specified output rate. Energy is the ability to do work, while capacity is the rate at which the work is done, called the power. Capacity is measured in Watts – a measurement of power – typically megaWatts (MW).

Q. Can the cost of capacity be directly attributed to a particular customer or a particular customer class?

A. Typically, no. The typical utility has a portfolio of resources that are used to serve many customers simultaneously. The result is that the joint costs of the portfolio of resources have to be *allocated* by some method of apportionment – rather than directly physically attributed – to customer classes. I will explain.

For a system where there are multiple generating units – multiple capacity resources – serving multiple customer at the same time, it is not possible to directly attribute a specific resource to a specific customer in a physical sense. The costs of the resources are joint costs. That is why under traditional utility regulation, joint costs are apportioned to customers or customer classes by an *allocation* method. There can be many types of allocation methods – various combinations of demand and energy measurements taken at various times – there is no unique solution. Regulators determine which allocation method results in a reasonable and fair allocation of joint costs to customer rate classes, after considering various factors and circumstances.

Q. What allocation method is used in Michigan?

A. Allocation of fixed generation costs in Michigan is determined by Commission rulings and, for some utilities, by state law. I&M relies on these allocation methods in its cost-of-service study, although as I will explain later it does not apply them in a meaningful way. Historically, arguments have been made about the ways to do cost allocations – for example, whether generation costs should be allocated by "75% demand

/ 25% energy," or the "50/25/25 method," or by 12 monthly contributions to peak demand or 4 summer month contributions to peak demand. However, just because a generation cost is allocated by a demand metric in the standard cost of service model does not imply cost causation or a definition or quantification of "capacity."

In its proposal to separate capacity costs from non-capacity costs, I&M merely makes several line item adjustments to its standard cost-of-service methodology, and asserts that ". . . these adjusted costs represent the rates that the Company will apply to customers taking service under the OAD Service section of the tariff, and <u>appropriately represent cost-causation from a ratemaking standpoint</u>." [*Heimberger testimony, page 5, lines 5-8, emphasis added.*]

This assertion is not accurate for two reasons. First, the cost-of-service model only models *allocation* of costs, not *causation* of costs. Second, to get to a reasonable quantification of separate and distinctive costs for "capacity" from a causal perspective, a different approach must be taken and additional adjustments made, which the standard cost-of-service model is ill equipped to handle.

Q. Is only I&M capacity used by all I&M distribution customers?

A. No, that is an outmoded concept given the existence of an RTO. A load serving entity (LSE) dedicates capacity to the RTO in an *amount* that represents the total *requirements* of the LSEs customers, but the capacity itself is not dedicated to the specific LSEs customers. Rather, the aggregated capacity from all LSEs is dispatched by the RTO to serve the aggregated customers in the RTO region.

I&M has not stated accurately the relationship of its capacity to its distribution customers. It assumes that its distribution customers are using only I&M's capacity. I&M witness William A Allen states, regarding his proposal:

> This approach ensures that I&M retail customers will pay the same cost based amount for capacity no matter whether they are taking standard service from I&M or taking service from an AES. This is a key feature of our proposal because, in either case, I&M's retail customers will be relying upon the same capacity." [*Allen testimony, page 4, lines 7-10.*]

Q. Do I&M's customers rely on I&M's capacity?

A. No, not directly. I&M's customers rely on a *portion of the aggregate capacity* that all LSEs – including I&M – dedicate to PJM in aggregate. I&M, as a Fixed Resource Requirement (FRR) entity in PJM, dedicates to PJM a sufficient amount of its resources to PJM to satisfy PJM's requirements for all load in its area, as an alternative to participating in PJM's capacity auction, the Reliability Pricing Model (RPM). Mr. Allen states this more correctly on page 5 of his testimony:

> Under PJM's RAA, a Load Serving Entity (LSE) can <u>meet the capacity requirements for its load obligations</u> from its own capacity resources or from the Reliability Pricing Model (RPM) market. A LSE that uses its own capacity resources to meet the capacity requirements for its load obligations is referred to as a FRR entity. . . . I&M self-supplies the capacity needs of its retail and firm wholesale customers and it therefore meets the standard for being an FRR entity. [*Allen testimony, page 5, lines 9-17, emphasis added.*]

Q. Why is this distinction relevant?

A. The distinction between providing capacity to customers and providing capacity to PJM to meet the obligations created by customer load is the *distinction between the provision of a retail product to retail customers and provision of a wholesale service to PJM or to another LSE*. This distinction is relevant because it illustrates that I&M has misapplied the traditional, cost-of-service, allocation method in proposing a charge to retail customers for a service that it does not provide to retail customers.

I&M does not sell a capacity product to retail customers. Therefore, to allocate a portion of I&M's total power supply costs to retail customer classes using allocation methods developed for the retail sale of electric products, as I&M has proposed, does not make sense.

Q. Regarding allocation methods, how are generation costs allocated?

A. Generation costs are allocated by rules of the Commission that have been determined in various previous rate cases, subject to certain methods specified in Michigan statutes, under PA 286 of 2008.

Sec. 11. (6) of PA 286 states: "The commission shall approve rates equal to the cost of providing service to customers of electric utilities serving less than 1,000,000 retail customers in this state."

Q. Would Electric Choice customers be allocated any capacity costs under cost of service provisions in PA 286?

A. No, they would not. The reason for this is straightforward: Electric Choice customers do not take power supply service from I&M. Electric Choice customers do not take energy from the utility and they do not contribute to the utility's monthly peaks. As a result, under the allocation principles established by the Commission, Electric Choice customers would not be allocated any of the utility's power supply costs.

Consequently, if the intent of PA 286 is for all customer classes, including Electric Choice customer classes, to pay rates equal to the cost of providing service to the respective classes, then the rates Electric Choice customers pay to I&M should not include any power supply costs.

Q. Doesn't the utility provide "capacity" to its Electric Choice customers?

A. No. As explained previously, the utility provides capacity to PJM, which uses the aggregate capacity dedicated by all LSEs to serve the load of all LSEs. That is why the solution proposed by I&M – an allocation of generation fixed costs to Electric Choice customers using traditional cost-of-service retail allocation techniques – has been misapplied.

Q. Are there other ways that I&M has misapplied cost of service principles?

A. Yes. As discussed, I&M allocates a portion of generation costs to Electric Choice customers that do not receive I&M's generation services. Mr. Allen offers such customers a portion of off-system sales margins: "Both customers served under standard service and customers served by an AES will receive a credit of 80% of I&M's off-system sales margins consistent with the Commission's Order in Case U-16801." [*Allen testimony, page 4, lines13-15.*]

However, because a decrease in I&M retail sales frees up an equivalent amount of energy for additional wholesale sales, the AES customers would be directly responsible for an increase in off-system sales. For example, assume that Electric Choice participation is the full 10% as currently limited. From Exhibit I&M-1 (WAA-1), this would represent approximately 280,000 MWh, which energy would be available for off-system sales. It would be reasonable for the Commission to find that Electric Choice customers should receive a portion of the margins commensurate with 280,000 MWh of off-system sales.

Further, the type of generation in a utility's portfolio, such as a nuclear plant with high investment costs but low variable costs, results in unreasonable and excessive costs being allocated to Electric Choice customers, who – again – do not take generation service from I&M.

Q. Why is the type of generation in a utility's portfolio relevant to the definition and pricing of "capacity" as a separate product or service?

A. As discussed previously, I&M's allocated generation costs do not represent either the cost or the value of "capacity" as a separate service.

There are two main reasons for owning capacity in an RTO market, versus purchasing from the market year by year:

1. to reduce the volatility of capacity costs in the long term, compared to purchase price or market auction price, and/or
2. to reduce or stabilize energy costs in the long term.

Decisions on the type, amount, and timing of investment in capacity are under control of I&M management, as the representative of investors/stockholders. For example, a decision may be made to invest large amounts in a nuclear or coal plant, with the expectation that in the long run savings in fuel will make the investment economic. This may be a wise decision in the long run. But, the high investments costs represent more than the short-term value of capacity alone. They represent the cost of an opportunity for long-term savings. There may be risks of not reaping the anticipated savings, and investors/stockholders are compensated for risk via the rate of return allowed by the Commission.

I&M's proposal effectively allocates to Electric Choice customers the cost of I&M's decisions to invest in ownership of generation. The customers on Electric Choice and the AESs that supply them do not receive the long-term benefits of I&M's investment. Therefore, neither Electric Choice customers nor AESs should pay the investment costs incurred by I&M.

In actuality, the AES receives only the benefit of short-term capacity, and so the AES should pay the fair value of that short-term capacity. I will recommend a pricing method in part II of my testimony.

Q. Are there specific items in I&M's cost-based proposal that should not be included in "capacity"?

A. Yes. I did a cursory review of I&M workpapers – the cost of service computer file – and found an item that should not be included in the "Capacity component of rates" of $120,455,006 that is shown on Exhibit I&M-3 (NAH-2), page 1 of 1, line 17, column titled "Total Retail."

The item is called "555—Purchase Power Expense Demand."[1] This appears to be the demand component of power purchased by AEP and allocated to the Michigan jurisdiction of I&M. The item is eventually used in determining Firm Sales Production Revenue [2], which is used in the allocation of demand-related production expenses, which is a factor in determining the $120 million "Capacity component of rates." The value of this item is $15,122,000. There is no explanation of why this item is included in "capacity" costs. The demand component of purchase power should not automatically be part of a "capacity" allocation. If the purchase were of a product that could be offered as "capacity" to PJM in fulfillment of capacity obligations, then this item may be a

[1] Workpaper computer file "MI 16801 SETTLEMENT Exhibits A1 JSS COS – excl Cook Security – for AES Capacity-r ("COS file"), worksheet COSS-AES, cell E1136, which includes in summation: worksheet JSS, row 459, column I, which equals H459 * the allocation factor in worksheet JAF JAF!D9.

[2] COS file, worksheet Allocators, cell D688.

legitimate capacity cost. If the purchase were some other product – for example, an option premium for dispatchable energy, or the fixed payment for a wind resource to meet renewable portfolio standards – then it would not be a legitimate capacity cost.

Further, if a purchase were to be part of capacity resources, then I&M would actually *save* such costs if customers moved to Electric Choice because it would not need to purchase as much power. Utility purchase power expenses are typically reduced when customers move to another supplier. Electric Choice customers should not be charged for "Purchase Power Expense Demand;" rather, they should be credited for the savings they create for remaining utility customers.

Another misapplication of cost causation is the inclusion of all operation and maintenance (O&M) expenses categorized as "demand" in I&M's allocation to "capacity," except for the adjustments that Ms. Heimberger lists on pages 4-5 of her testimony. These O&M expenses pay not only for maintaining the generation plants in a state of readiness, but also pay for the operation of the plants to produce energy and additional maintenance of the plants due to energy production. "Capacity" costs should not include any O&M expenses other than the minimum needed to keep the plant open and operable, and thus should not include any O&M, whether labeled "demand" or not, that is for the purpose of actually operating the plant to produce power.

Also, Electric Choice should be properly credited with savings that benefit remaining utility customers when customers move to Electric Choice. A significant saving is marginal fuel. When a customer moves to Electric Choice, there is a decrease in the amount of fuel that the utility must use to generate power for remaining customers. Since generation is typically dispatched in merit order – from low cost to high cost – the fuel savings occur at the marginal generating unit, the highest variable cost unit. Consequently, when customers move to Electric Choice, the *average* per MWh cost of fuel for the remaining *customers* decreases. The fuel savings are flowed back to the remaining utility customers through the Power Supply Cost Recovery proceeding.

In I&M's cost of service, fuel is removed, as it should be; but there is no credit for the additional savings of the difference between average fuel cost and marginal fuel cost, that accrues to the benefit of remaining customers yet is actually caused by the movement of customers to Electric Choice.

Q. What is your conclusion regarding how I&M has applied cost-of-service principles to calculate "capacity" cost?

A. The "capacity" cost that I&M has calculated contains much more than the cost of pure capacity as a separate product. It contains additional investment costs that gain the ability to generate low-cost energy from coal and nuclear fuel over a long time – decades. It also contains expenses of actually operating the plant to produce such low-cost energy, and does not properly credit fuel savings. And, it contains some specific costs of purchased power that may be erroneously categorized as capacity costs.

The critique above is not intended to question I&M's competency or good faith in using the standard cost-of-service model. The underlying difficulty is that there are simply too many complicated adjustments that have to be made if the standard model is to determine "capacity" and its fair cost. "Capacity" is a sub-product of the generation portfolio, and the traditional use of the model to *allocate* generation costs by type – fuel, labor, investment, taxes, etc. – does not provide for separating out generation *products* such as capacity, spinning reserve, ramping ability, etc.

The cost-of-service model is not designed to determine cost causation or to determine the cost of joint generation sub-products. There is no "capacity product" that is defined within the model or is readily determined by using the standard allocation techniques within the model. It is a tool that works well for cost allocation to retail rate classes under rules and guidelines established by the Commission. But its arithmetic is not readily adaptable to analysis of cost causation.

Utility cost of service is a complicated undertaking. Attempting to adjust a traditional retail cost-of-service determination to charge for services not being taken by a customer class such that the charges end up fair and reasonable may be quite controversial and complex. There is a simpler solution.

My recommendation to the Commission is to deny I&M's cost-based proposal. It does not apply cost of service principles to determine "capacity" accurately. It does not define the desired product, nor does it attached a "cost causation" price to the product it does define.

Q. Isn't the capacity that I&M provides to PJM still being used by PJM, and if so, should not I&M be compensated for the use of the capacity?

A. Yes, it is being used by PJM; and of course I&M should be compensated. The question at hand has two parts: (1) how I&M should be compensated and (2) to what extent it should be compensated.

Q. Regarding the first part of the question, how should I&M be compensated?

Under the FRR alternative, the use of I&M's capacity satisfies PJM's capacity requirements for a supplier – the AES – for load that subsequently has switched from I&M to the AES. As a result, the AES benefits since the AES does not have to provide additional capacity to cover the switched load. In essence, I&M has provided a wholesale service to the AES. Therefore, the natural solution is that the AES compensate I&M for the value of the service rendered.

Q. What is your recommendation to the Commission regarding *how* I&M should be compensated?

A. Instead of I&M's proposal to charge Electric Choice customers, I recommend that the Commission approve a *charge by I&M to the AES serving the switched customer*, as compensation for the service provided to the AES – the dedication of I&M's capacity to PJM to cover the AES's capacity obligations for the switched load.

This type of charge should endure as long as I&M is an FRR entity. If and when I&M is no longer an FRR entity, no such transfer charge will be needed, because PJM will automatically adjust the daily capacity obligations of I&M and the AES based on actual customer load.

II. Proposed Alternative Compensation Method

Q. Regarding the second part of the question at hand, *to what extent* should I&M be compensated for the wholesale service of providing capacity to PJM that meets the requirements of load that has switched to an AES?

A. I&M should be compensated for the *fair value of the service* that it provides. In PJM, the fair value of capacity for various time periods is established by the Reliability Pricing Model (RPM). The RPM price is determined by an auction. PJM as an RTO charges the RPM price to LSEs in PJM to pay for capacity purchased at auction to cover the aggregate load in PJM – except PJM does not charge LSEs who have opted, as FRRs, to dedicate specified owned capacity to fulfill their capacity requirements separate from the auction.

Q. What is your recommendation to the Commission?

A. As stated previously, the Commission should approve a charge by I&M to the AES to which a customer has switched. I recommend that the charge should equal *PJM's*

RPM "Final Zonal Capacity Price," for the zone that includes the Michigan region of I&M.

The charge should be applied on a per MW-day basis during the portion of PJM's "Delivery Year" that the customer takes service from the AES.

Q. What are the benefits of using the RPM price as compensation?

A. The RPM price:

a. <u>represents the value</u> of capacity in the PJM region,

b. <u>changes as the value of capacity changes</u> in a future Delivery Year,

c. <u>enables competitive supply</u> offered by AESs to reflect fair market value,

d. <u>provides market-based compensation</u> to I&M for the use of its capacity,

e. <u>is equivalent to the savings</u> that I&M would experience if it participates in the RPM capacity,

f. <u>allows the Commission</u> to set a fair and reasonable transfer price in this proceeding very simply and clearly, while maintaining the opportunity for I&M to recover any revenue deficiency or net stranded costs – which may be complex and controversial – in a separate proceeding.

Q. How will using the RPM price affect retail competition in I&M's area?

A. The RPM price will enable an AES to offer a competitive price that reflects the visible wholesale market price of capacity. The AES will have to compensate I&M the "going rate," so to speak, for capacity – no more, no less.

Mr. Roy Boston will testify for Energy Michigan regarding the effects on competition of I&M's proposal of charging allocated fixed costs to Electric Choice customers versus my proposal of charging the RPM price of capacity directly to AESs.

Sec. 11. (6) of PA 286 also states: "If, in the judgment of the commission, the impact of imposing cost of service rates on customers of a utility would have a material impact, the commission may approve an order that implements those rates over a suitable number of years." The Commission does not appear to be obligated to approve only rates stemming from I&M's cost-of-service model, if there are other requirements that must be met, such as opportunity for competition. Sec. 10a. (1) of PA 286 states: "The commission shall issue orders establishing the rates, terms, and conditions of service that allow all retail customers of an electric utility or provider to choose an alternative electric supplier."

In a recent order, the Public Utility Commission of Ohio struck a balance between the need for competitive supply by customers and the need for recovery of costs by utilities.[3] Implementing the RPM price in Michigan in this proceeding, coupled with opportunity for I&M to recover its fair costs in a separate proceeding if and when needed, may enable the Michigan Commission to strike a similar balance. This is the same

[3] *PUC of Ohio, July 2, 2012 Order, Case No. 10-2929-EL-UNC.*

situation that would occur if I&M were to move to the RPM construct, versus its present FRR construct.

Q. If the Commission were to desire to establish a capacity charge based on I&M's costs, are there alternatives other than I&M's proposal?

Yes. Although I do not recommend a cost-based charge, if there were a cost-based charge it would be more logical to determine I&M's costs of capacity by first defining and determining capacity as a separate product. One way would be to look at I&M's cost of peaker generation on a minimum "keep the plant open" basis, rather than at the cost of the entire generation portfolio as I&M has proposed.

III. Compensation for Capacity versus Recovery of Revenues

Q. I&M's proposal separates power supply charges into "capacity" and "non-capacity" and assesses the "capacity" portion to Electric Choice customers. What is the practical effect of this proposal?

A. I&M witness Ms. Nancy Heimberger defines "non-capacity" as follows: "The non-capacity component represents costs that the Company would not incur when providing service to the customers opting to take service from an AES under the Open Access Distribution (OAD) Service section of the tariff. [*Heimberger testimony, page 3, line 19, to page 4, line 2.*]

The practical effects are (a) Electric Choice customers would pay a portion of I&M's fixed costs and (b) I&M would continue to collect all its fixed costs – as defined by Ms. Heimberger – no matter what the level of Electric Choice.

Q. Is I&M's proposal consistent with the concept of fair and reasonable compensation for the use of its capacity?

A. No, not at all. The proposal appears to deal with compensation for capacity merely by the separating charges for capacity and non-capacity; but essentially it is simply a method to continue to recover all its fixed costs. There is an implicit assumption that the reduction of revenue to cover fixed charges that would occur if a customer moves to Electric Choice must be recovered, and recovered only from the specific Electric Choice customer.

This assumption is equivalent to the assumption that (a) the reduction of revenue to cover fixed costs represents stranded costs, (b) that I&M has the authority to determine and collect stranded costs, and (c) that I&M has the authority to determine that only Electric Choice customers should pay for stranded costs.

Q. Does I&M experience stranded costs when a customer switches to Electric Choice?

A. I don't know. The answer to that question is likely to be extremely complex. The Commission would have to distinguish between stranded costs and variation in revenue due to sales variation. Also, the Commission may want to review any savings or mitigation revenues that the utility might experience when customers move to Electric Choice. Further, the Commission might assess whether or not I&M is earning its authorized rate of return or has sufficient revenues to cover fixed costs.

In any event, I&M has made no claim or showing that it is suffering or will suffer any stranded costs net of savings or that it will not have sufficient revenues to cover its fixed costs.

Q. Is there a need to determine stranded costs or methods to recover additional revenue for I&M in this proceeding?

A. In my opinion, no. This proceeding should only determine the fair compensation for I&M for the use of its capacity.

If and when I&M believes it is not recovering enough revenue to cover its fixed costs, then I&M still has the opportunity to apply to the Commission for a remedy. That opportunity is not harmed by the determination in this proceeding that the compensation to I&M for capacity should be the RPM market price and should be paid by the AES.

The Commission has dealt with recovery of revenues for other utilities in a number of forums, including general rate cases, the Choice Incentive Mechanism, and specific proceedings. I&M is afforded the same opportunities as other utilities.

Further, Mr. Allen's Exhibit I&M-1 (WAA-1) shows that at the time of I&M's filing, only 0.01% of its sales was being served by AESs on Electric Choice. This means that, coupled with the ability to set rates based on a forecasted test year, I&M incurs little risk if the Commission were to deal only with the issue of compensation for capacity in this proceeding, and defer any lost revenue issues to a separate proceeding in the future if and when I&M were to apply to the Commission.

Summary of Recommendations

Q. Please summarize your recommendations to the Commission.

A. My recommendations for compensation to I&M, as an FRR, for the use of its capacity when a customer switches from I&M to an AES under the Electric Choice program are:

1. The Commission should deny I&M's proposed charges to Electric Choice retail customers. The charges do not represent "capacity," nor do they form an accurate cost calculation of "capacity"; and Electric Choice customers do not take power supply service from I&M.

2. The Commission should approve a charge by I&M to the AES, the entity that benefits from the dedication of I&M's capacity to PJM.

3. The charge to the AES should equal the value of capacity as set by PJM's RPM Final Zonal Capacity Price. This represents fair market value.

4. The charge should be applied on a per MW-day basis during the portion of PJM's Delivery Year that the customer takes service from the AES.

5. This proceeding should determine only the compensation to I&M for capacity. Issues of revenue recovery should be deferred to a separate proceeding in the future, upon application by I&M.

6. If the Commission decides that a charge based on cost allocations is a better solution than the RPM price, then the cost of capacity should be based on I&M's cost of peaking generation, not the cost of its entire generation portfolio that includes much more than pure "capacity."

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

ALEXANDER J. ZAKEM

46180 Concord
Plymouth, Michigan 48170
734-751-2166
ajzakem@umich.edu

CONSULTANT – MERCHANT ENERGY AND UTILITY REGULATION

Provide strategies and technical expertise on competitive market issues, transmission issues, state and federal regulatory issues involving the electricity business, and associated legal filings. Scope includes the Midwest ISO Energy Market and Resource Adequacy, FERC proceedings on transmission and market tariffs, state rules for competitive supply, and negotiation of settlements.

PRIOR POSITIONS: Quest Energy, LLC – a subsidiary of Integrys Energy Services

Vice President, Operations **March 2002 to December 2003**

Responsible for the planning, acquisition, scheduling, and delivery of annual power supply and transmission, to serve competitive retail electric customers.

- ***Power Planning*** **--** Designed and negotiated customized long-term power contracts, to reduce power costs and exposure to spot energy prices.
- ***Transmission*** -- Revamped transmission strategy to reduce transmission costs.
- ***Load Forecasting*** -- Instituted formal short-term forecasting process, including weather normalization.
- ***Risk Management*** -- Developed summer supply strategy including call options to minimize physical supply risk at least cost. Instituted probabilistic assessment of forecast uncertainty to minimize transmission imbalance costs.
- ***Contract Management*** – Negotiated and recovered liquidated damages for power supply contracts. Included cost of transmission losses into customer contracts.
- ***Operations Capability*** **--** Expanded the Operations staff. Oversaw daily activity in spot market purchases. Instituted back-up capability, including equipment and processes, enabling the company to schedule and deliver virtually all power during the August 2003 blackout in the Midwest.

PRIOR POSITONS : <u>DTE Energy / Detroit Edison — 1977 to 2001</u>

Director, Power Sourcing and Reliability **May 1998 to April 2001**

Director of group responsible for monthly, annual, and long-term purchases and sales of power for Detroit Edison, including procuring power for the summer peak season.

- ***Planning*** -- Planned summer power requirements for Detroit Edison, including mix of generation, option contracts, hub purchases, load management, and transmission, which balanced and optimized physical risk and financial risk.

- ***Contract Management*** – Established decision, review, and approval process for evaluation and execution of power transactions, including mark-to-market valuation.

- ***Execution*** **--** Executed summer plans, contracting annually for purchased power and transmission services. Directed negotiations for customized structured contracts to provide the company with increased operating flexibility, dispatch price choices, and delivery reliability.

- ***Risk Management*** – Developed an optimizing algorithm using load shapes to minimize corporate exposure to volatile power prices. Developed a hedging strategy to fit power purchases to the corporation's risk tolerance level.

- ***Acquisitions*** **--** Team leader for acquisition of new peakers.

- ***Settlements*** **--** Negotiated and settled liquidated damages claims.

Relevant prior positions within Detroit Edison

<u>Position</u>	***<u>Organization</u>***	***<u>Time Period</u>***
Director, Special Projects	**Customer Energy Solutions**	**Apr 97 to May 98**

Leader of several special projects involving the transformation of the corporation's merchant energy functions into competitive business units, including merger explorations and the start up of DTE Energy Trading (DTE's power marketing affiliate).

Directed filings to the Federal Energy Regulatory Commission to establish DTE Energy Trading as a power marketer and to gain authority for sales, brokering, and code of conduct. The FERC used DTE's flexible utility/affiliate code of conduct as precedent for rulings for other power marketers.

Director, Risk Management	**Huron Energy (temp affiliate)**	**Jan 97 to Apr 97**

Leader of team responsible for competitive pricing of wholesale structured contracts and for acquiring risk management hardware and software to support risk management policy. Prepared Board resolutions to implement risk management policy.

Director, Contract Development	**Customer Energy Solutions**	**Jan 96 to Dec 96**

Leader of team that formulated a business strategy for the corporation in competitive power marketing. Team leader on project evaluating an existing steam and electricity contract, recommending and gaining Board approval for revamping the corporation's Thermal Energy business and strategy.

Project Director	**Executive Council Staff & Corporate Strategy Group**	**Jan 91 to Dec 95**

Project leader for competitive studies, including business risk, generation pooling, and project financing in the merchant generation industry. Team member and/or team leader for analyses of merger and acquisition opportunities

Special Assignment	**Executive Council Staff**	**Mar 90 to Dec 90**

Special assignment related to long-term industry strategies and mergers and acquisitions.

Pricing Analyst	**Marketing / Rate**	**Aug 82 to Mar 90**

Developed, negotiated, and implemented an innovative standby service tariff. Testified as an expert witness in regulatory proceedings and in state legislative hearings.

Engineer	**Resource Planning**	**Aug 79 to Dec 81**

Member of the company's electric load forecasting team, responsible for SE Michigan energy and peak demand forecasting, and for risk analysis. Developed the company's first residential end-use forecast model.

PRIOR POSITIONS: **<u>Prior to DTE Energy</u>**

Lear Siegler Corporation, ACTS Computing division, systems analyst and programmer from January 1973 to July 1977.

EDUCATION: M. A. in mathematics, University of Michigan, 1972
B. S. in mathematics, University of Michigan, 1968

MILITARY: U. S. Army, September 1968 to June 1970.
Viet Nam service from June 1969 to June 1970.
Honorably discharged.

PROFESSIONAL: Member, Engineering Society of Detroit (1979-present)

PUBLICATIONS & PAPERS:

- "Competition and Survival in the Electric Generation Market," published in *Public Utilities Fortnightly*, December 1, 1991.

- "Measuring and Pricing Standby Service," presented at the Electric Power Research Institute's "Innovations in Pricing and Planning" conference, May 3, 1990.

- "Assessing the Benefits of Interruptible Electric Service," presented at the 1989 Michigan Energy Conference, October 3, 1989.

- "Principles of Standby Service," published in *Public Utilities Fortnightly*, November 24, 1988.

- "Progress in Conservation," a satirical commentary published in *Public Utilities Fortnightly*, October 27, 1988.

- "Comparing Utility Rates," published in *Public Utilities Fortnightly*, November 13, 1986.

- "Uncertainty in Load Forecasting," with co-author John Sangregorio, published in *Approaches to Load Forecasting*, Electric Power Research Institute, July 1982.

PREVIOUS TESTIMONY:

- Michigan Public Service Commission, U-16794
- Michigan Public Service Commission, U-16566
- Michigan Public Service Commission, U-16472
- Michigan Public Service Commission, U-16191
- Michigan Public Service Commission, U-15768.
- Michigan Public Service Commission, U-15744.
- Federal Energy Regulatory Commission, Docket No. EL04-135 & related dockets.
- Michigan Public Service Commission, U-12489.
- Michigan Public Service Commission, U-8871.
- Michigan Public Service Commission, U-8110 part 2.
- Michigan Public Service Commission, U-8110, part 1.
- Michigan Public Service Commission, U-7930 rehearing.
- Michigan Public Service Commission, U-7930.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion,	)	
to initiate a proceeding to establish a state	)	
compensation mechanism for alternative	)	Case No. U-17032
electric supplier capacity in INDIANA	)	
MICHIGAN POWER COMPANY's Michigan service	)	
territory.	)	

DIRECT TESTIMONY OF

ROY BOSTON

ON BEHALF OF INTERVENOR

ENERGY MICHIGAN

DIRECT TESTIMONY OF ROY BOSTON

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS

A. My name is Roy Boston, and my business address is 1901 Butterfield Road, Downers Grove, Illinois 60515.

Q. BY WHOM ARE YOU EMPLOYED

A. I am employed by Noble Americas Energy Solutions LLC.

Q. PLEASE DESCRIBE YOUR POSITION WITH NOBLE AMERICAS ENERGY SOLUTIONS LLC

A. I am Strategic Planning & Policy Manager – East for Noble Americas Energy Solutions LLC. In that role, I am responsible for directing and implementing regulatory and legislative policies for Noble Americas Energy Solutions LLC's retail business interests in the Midwest portion of the United States, which includes the State of Michigan.

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science degree in Business Economics & Public Policy from the Indiana University School of Business in Bloomington, Indiana in 1982 and a Juris Doctorate degree from Southwestern University School of Law in Los Angeles, California in 1985. I have about 25 years experience in all facets of the energy industry. Beginning in 1985 as an attorney I was engaged in the practice of administrative law prior to the advent of open access in the interstate natural gas business that predated competition at the retail state level for electricity. I served as an executive Assistant for a Commissioner on the Illinois Commerce Commission from 1986 through 1990. I was the Manager of State Government Affairs for the Natural Gas Pipeline Company of American from 1991 to 1996. I was employed as a Director – Global Government Affairs for the Enron Corporation from 1996 through 2001. I was employed at Illinois Power Company and Dynegy Corp. as a Manager of Government Affairs from 2001 until 2004 and have been employed at Noble Americas Energy Solutions LLC and its predecessor, Sempra Energy Solutions from 2005 until present.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Energy Michigan.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I have testified before this Commission in 1995 in a docket addressing the reasonableness of certain non-physical natural gas transportation charges proposed by Consumer Energy.

Q. WHAT IS ENERGY MICHIGAN INTEREST IN THIS PROCEEDING?

A. Energy Michigan has an interest in the development and maintenance of competitive retail markets for electricity for all customers in Michigan. Noble Americas Energy Solutions LLC ("Noble Solutions") is a member of Energy Michigan and, as an active Alternative Electricity Supplier ("AES"), is licensed to sell electricity to customers in the State of Michigan. Noble is also registered with Indiana Michigan Power Company ("I&M")as an AES to transact with retail customers on its system in Michigan. Noble Solutions has contracts for retail electric service with several customers located within the I&M service territory in Michigan. Energy Michigan is concerned that the proposed capacity rate for AES-supplied customers on the I&M Michigan system will negatively impact customers' ability to capture savings by switching service from the fully bundled utility rate to service provided by AES such as Noble Solutions, and other AES service providers.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to show that the I&M proposed capacity rate, if approved by the Commission, would not ensure that Michigan retail customers will have a choice of suppliers. If I&M's proposed capacity rates were approved by the Commission competition would not develop in the I&M service territory and the statutory requirement that rates be set to encourage competition would not be served. Energy Michigan's witness Alex Zakem will address the appropriateness of I&M's proposed capacity cost structure.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring Exhibit EM-2 (RB-1) attached to my testimony.

Q. WHAT IS THE INTEREST OF YOUR EMPLOYER, NOBLE AMERICAS ENERGY SOLUTIONS LLC, IN PRESENTING TESTIMONY IN THIS CASE?

A. My employer is engaged in providing service to retail electric customers in Michigan to the extent that it can provide a value proposition for these customers to switch from fully bundled utility-provided service to competitively-provided electricity service. Noble Solutions is a member of Energy Michigan and pursuant to the mission of Energy Michigan, it supports the development of competitive retail electric markets in Michigan. Noble Solutions would like to provide AES service to customers in the I&M service territory if the total of charges such customers would pay are less than those charged by I&M to the same customers as fully bundled service. On the other hand, if the total of all applicable charges, including utility distribution charges and energy supply charges, together with other delivery service charges does not permit customers on the I&M system to experience savings if they were to switch to AES supplied service, as measured against the applicable I&M fully bundled service, then AES suppliers like Noble Solutions will not be able to compete against those fully bundled services and competition will not develop in the I&M service territory.

Q. WHAT TYPE OF CUSTOMERS DOES NOBLE SOLUTIONS SERVE AND WHAT TYPES OF SERVICE PRODUCTS DOES NOBLE SOLUTIONS OFFER?

A. Noble Solutions serves industrial and commercial customers. Noble Solutions offers to retail electric customers a number of products, including, but not limited to: 1) fixed price service; 2) block and index service; 3) full requirements, load following service; 4) index-priced service; and 5) a host of green products. In order for Noble Solutions to provide these and other services to retail electric customers, the rates and charges that comprise the delivery charges used to provide the electricity to the customer must provide the customer with a savings opportunity for them to make a rational economic decision to switch from fully bundled utility service to Noble Solutions' AES service.

Q. WHAT IS THE SUMMARY OF YOUR RECOMMENDATION?

A. I recommend that the Commission reject AEP's embedded cost proposal to establish a state compensation mechanism for its capacity and instead, the Commission should adopt the final zonal clearing price for the RPM for the uncongested portion of western PJM as the just and reasonable rate for capacity charged to AES providers in its service territory.

Q. WHAT IS YOUR UNDERSTANDING ABOUT THE COST PROPOSAL PROVIDED BY I&M FOR CAPACITY FOR AES LOAD SERVED IN I&M'S MICHIGAN TERRITORY?

A. I&M has filed to impose rates for capacity provided to customers served by AES that, if adopted would recover what I&M has characterized as an "embedded cost of service". The capacity charges proposed by I&M vary by rate classes. Energy Michigan's witness Alex Zakem addresses the appropriateness of some of the charges I&M proposes to include in its formula rate structure as well as the appropriateness of using a retail cost allocation approach to developing a wholesale service to be provided to AES in order for them to serve their retail electric load.

Q. WHAT IS THE LEGAL STANDARD WITH WHICH TO MEASURE THE CAPACITY COMPENSATION MECHANISM AND ITS EFFECT ON COMPETITION?

A. My understanding is that MCL 460.10(2) states that the purpose of the first Choice statute (Public Act 141) is to "ensure that all retail customers of this state have a choice of electric suppliers and to foster competition in the provision of electric supply." In addition MCL 460.10a(1) requires the Commission "… to issue Orders establishing rates, terms and conditions of service that allow all retail customers of electric utilities…to choose an Alternative Energy Supplier." A utility claiming that it has costs incurred under regulation that are not recoverable in a competitive retail electric market has opportunities to file to recover those costs, but only to the extent that those costs which are prudently incurred and which do not prevent competition Such a showing should be accompanied by netting the full benefits of competition against the claimed costs.

Q. HAS I&M FILED TO RECOVER ANY OF ITS CLAIMED "EMBEDDED COSTS" AS A STRANDED COST?

A. No. The nature of its capacity filing appears to be that it has claimed embedded costs, incurred under the regulated structure, that are not recoverable in a competitive market. However, the rates produced by recovering those costs prevent retail electric competition. What I&M has also failed to do is to demonstrate that those costs are fully netted against benefits from the development of competition although competition has not arisen in its service territory until 2012. It appears that I&M is seeking here to collect stranded costs under the guise of an embedded cost structure and has avoided showing the effect of those rates on competition. Energy Michigan supports the recovery by utilities of their prudently incurred costs that are used and useful in the provision of jurisdictional utility service. I simply do not think that I&M has amply demonstrated that the Commission should approve its filed rates especially in light of the damage it would cause to retail electric competition and to Electric Choice.

Q. WHAT WOULD BE THE EFFECT ON COMPETITION IF THIS I&M RECEIVED APPROVAL FOR THIS RATE FOR CAPACITY PROVIDED TO AES-SERVED LOAD?

A. The effect on competition is that such a high rate would virtually end any competition in the I&M service territory.

Q. WHY DO YOU BELIEVE THAT APPROVAL OF I&M'S PROPOSED CAPACITY RATES WOULD END COMPETITION IN ITS SERVICE TERRITORY?

A. I believe that it would end competition because a combination of all of the rate components for services needed by an AES to deliver electricity to a retail customer together with an assumed market price for electricity would exceed the fully bundled rate currently applicable to most, if not all customers.

Q. DO YOU HAVE AN EXAMPLE SHOWING HOW CAPACITY COSTS IN THE RANGE SUGGESTED BY I&M'S CLAIMED EMBEDDED COST STRUCTURE WOULD IMPACT CUSTOMER SAVINGS?

A. Yes. Exhibit EM-2 (RB-1) attached to my testimony shows hypothetical customers taking utility fully bundled service under five different rate classes as shown in Column B: Small

General Service; Medium General Service – Secondary; Medium General Service – Primary; Large General Service – Primary; and Large Power – Sub-transmission. Column A shows the rate codes for each hypothetical customer. Column C provides assumed annual customer usage. Column D shows annual cost to each customer for service from the utility using fully bundled service under the applicable rate description. Column E shows the annual cost of serving each customer applying an assumed market-priced electricity supply charge which includes RPM-priced capacity. Column F shows the per-unit utility price for each customer, and is Column D divided by assumed consumption provided in Column C. Column G represents a hypothetical per KWh market price for electricity supply for each customer and includes RPM-priced capacity. Column H compares Columns F and G and derives an estimated per kWh percentage savings for each customer comparing the utility unit price against the hypothetical market-based per unit price which includes RPM pricing for capacity. As you can see, Column H projects substantial savings for all of the hypothetical customers in the rate classes listed assuming they receive RPM-priced capacity and a market price for electricity.

Column J shows what impact an increase in capacity prices, to levels suggested by I&M's claimed embedded cost pricing structure will have on customers that are served by an AES. The capacity price included is that provided by I&M witness Hix in his testimony in this Docket. Column K shows the relative savings for each of the hypothetical customers, on a percentage basis, as measured against the fully bundled utility-provided service. As you can see, none of the customers are projected to experience any savings if the I&M proposed capacity rate levels are approved. This lack of savings makes it highly unlikely, in my experience, for an AES to encourage a customer to switch service from the fully bundled utility service to a competitively-priced AES service[1].

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[1] In the hypothetical customer examples provided in Exhibit RB-1, the cost for renewables is excluded because the obligation to provide renewable energy credits or renewable energy under Michigan law is equal for utility and AES provider service. Also omitted from this calculation is any margin for the AES provider since the intent of the comparison is to illustrate the difference in costs between I&M's proposal and the RPM price.

Q. WHAT CONCLUSION DO YOU REACH FROM THE ANALYSIS PROVIDED BY EXHIBIT RB-1?

A. The conclusion I reach is that for the rate classes I have examined in Exhibit RB-1, customers will experience savings by switching from fully bundled utility service provided that they are paying the prevailing RPM price for capacity. However, if the Commission approves the capacity rates proposed by I&M, customers will pay more if they switch to AES-provided service. Based on the data, analysis and assumptions provided in Exhibit EM-2 (RB-1), it is my conclusion that if I&M's proposed capacity rates are approved using its claimed embedded cost methodology, no competition will exist on its system for retail electric customers in the rate classes I have examined.

Q. WHY SHOULD THE COMMISSION BE CONCERNED THAT IN YOUR HYPOTHETICAL EXAMPLE THE CUSTOMERS EXPERIENCE NO SAVINGS IF THE COMMISSION APPROVES I&M'S PROPOSED CAPACITY RATES?

A. The Commission should be concerned because if customers do not anticipate having savings, they will not switch service from the utility to the AES. If I&M's capacity rates are approved at a level that precludes customers from experiencing savings they simply will not switch service and I&M will be the only service provider in its service territory. In this case, these higher capacity rates, as requested by I&M will not allow all retail customers to choose an AES, as provided for under MCL 460a(1) cited above. Basically, the AES has to be able to show the customer that they have some potential to save in comparison to their fully bundled utility price or else they will not leave the utility for AES service.

Q. WHAT IS THE PROBLEM IF CUSTOMERS STAY WITH I&M INSTEAD OF SWITCHING SERVICE TO AN AES?

A. My understanding of Michigan law is that the Commission is charged with encouraging competition. Quite simply, approval of a capacity rate that is so high that it removes from customers all reasonable expectation that they will save money by switching to an AES, will prevent the competitive market from developing and would destroy any existing competition. Thus, approval of the I&M proposed capacity rates will have the opposite effect from encouraging the development of competition: it will destroy customers' value propositions that are necessary for the competitive market to develop. For this reason, I believe that I&M's proposed capacity pricing proposal should be rejected by the Commission, and, instead, the Commission should adopt a mechanism that uses the PJM Interconnection RPM auction-derived price to be the basis for pricing capacity in I&M's Michigan service territory for AES-served load.

Q. DO YOU BELIEVE THAT THE COMMISSION SHOULD THEN SET RATES ACCORDING TO WHETHER THEY ARE AT A LEVEL TO ENCOURAGE COMPETITION AS REQUIRED BY MICHIGAN LAW?

A. No. Capacity rates should be set at a reasonable level given a visible market price. The establishment of capacity rates is too complex to use I&M's performance cost model as the Commission's only standard, and that is not what I recommend. Michigan law requires that rates for service must be based on the costs of providing those services to the various classes, and that is what I recommend that the Commission do in this case. I recommend that the appropriate cost to be used for establishing a capacity rate for AES-served load is the visible cost for capacity established through the auction run by PJM for capacity -- RPM.

Q. Who should be charged the RPM capacity cost?

A. The AES per the recommendation of Alex Zakem.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Fixed Price; Fully Bundled
1 year out 9/1/12

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Rate Code	**Rate Description**	**Annual KWh**	**Utility Annual Cost**	**Annual Cost (W RPM)**	**Utility Unit Cost**	**Price**	**% Savings**		**Price (W/I&M-Proposed Cap Rates)**	**% Savings**				
211	Small General Service	10,007	$ 730	$ 460	$ 0.0730	$ 0.0460	37%		$ 0.0836	-15%				
215	Medium General Service - Secondary	453,240	$ 32,385	$ 23,772	$ 0.0715	$ 0.0525	27%		$ 0.0947	-33%				
217	Medium General Service - Primary	3,462,000	$ 237,997	$ 184,040	$ 0.0687	$ 0.0532	23%		$ 0.0936	-36%				
244	Large General Service - Primary	7,245,000	$ 385,374	$ 296,176	$ 0.0532	$ 0.0409	23%		$ 0.0686	-29%				
308	Large Power - Subtransmission	18,560,000	$ 1,098,955	$ 837,613	$ 0.0592	$ 0.0451	24%		$ 0.0765	-29%				

Rate Code	**Rate Description**	**Estimated Network and Capacity PLC (KW)**	**Energy**	**Swing**	**Distribution Losses**	**Ancillary Services and ISO Fees**	**Network Transmission**	**TEC**	**Balancing Operating Reserve - Reliability**	**Balancing Operating Reserve - Deviation**	**RPM Capacity**	**I&M Proposed Capacity**	**Price**	**Price (W/I&M-Proposed Cap Rates)**
211	Small General Service	1.43	$ 0.0345	$ 0.0020	$ 0.0021	$ 0.0014	$ 0.0041	$ 0.0003	$ 0.0003	$ 0.0002	$ 0.0012	$ 0.0389	$ 0.0460	$ 0.0836
215	Medium General Service - Secondary	151	$ 0.0340	$ 0.0020	$ 0.0020	$ 0.0014	$ 0.0091	$ 0.0007	$ 0.0003	$ 0.0002	$ 0.0028	$ 0.0451	$ 0.0525	$ 0.0947
217	Medium General Service - Primary	1,175	$ 0.0354	$ 0.0020	$ 0.0011	$ 0.0014	$ 0.0093	$ 0.0007	$ 0.0003	$ 0.0002	$ 0.0028	$ 0.0432	$ 0.0532	$ 0.0936
244	Large General Service - Primary	1,494	$ 0.0321	$ 0.0020	$ 0.0010	$ 0.0014	$ 0.0028	$ 0.0003	$ 0.0003	$ 0.0002	$ 0.0009	$ 0.0286	$ 0.0409	$ 0.0686
308	Large Power - Subtransmission	4,000	$ 0.0330	$ 0.0020	$ -	$ 0.0014	$ 0.0059	$ 0.0006	$ 0.0003	$ 0.0002	$ 0.0018	$ 0.0332	$ 0.0451	$ 0.0765

Footnotes

1 Price includes energy, shaping, swing premium, losses, capacity, network transmission, renewable portfolio standards, balancing operating reserves, ancillary services and ISO fees.
2 Transmission & capacity obligations, pricing was estimated. Shaping & swing premia, network transmission & capacity obligations were estimated.
3 The capacity rates used for the Price column is RPM ($16.74 for PY 12-13 and $27.86 for PY 13-14).
4 The capacity forecast pool requirement used is 8.69%. The reserve margin used is 6.685% for PY 12/13 and 8.812% for PY 13/14.
5 The utility cost includes the Power Supply Charges (Capacity and Non-Capacity), Power Supply Cost Recovery Fatory and Rate Realignment Charges.
6 The rate used for Network Transmission is for PY 12/13, $27,430.91/MW-Yr.
7 The rate used for Transmission Enhancement Charge is $0.30/MW-h.
8 The capacity rates used for the Price (W/I&M-Proposed Cap Rates) column is proposed tariff rates listed below for each Rate Code.

Rate Code	**Capacity Rates**
211	Energy Charge (Cents/kWh)-First 2,000 Kwh 4.685; Anything over 2,000 Kwh 1.883
215	Demand Charge ($/kW) 1.18; Energy Charge (Cents/kWh) 4.062
217	Demand Charge ($/kW) 1.15; Energy Charge (Cents/kWh) 3.945
244	Demand Charge ($/kW) 4.81; On Peak Energy Charge (Cents/kWh) 5.581
308	Demand Charge ($/kW) 7.59; 1st 210 On Peak Kwh used per Kw (Cents/kWh) 5.45

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the matter, on the Commission's own motion, to initiate a proceeding to establish a state compensation mechanism for alternative electric supplier capacity in INDIANA MICHIGAN POWER COMPANY'S Michigan service territory.	))))))	Case No. U-17032

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF INGHAM)

Monica Robinson, the undersigned, being first duly sworn, deposes and says that she is a Legal Secretary at Varnum LLP and that on the 16th day of July, 2012, she served a copy of the Testimony and Exhibits of Alexander J. Zakem and Roy Boston on Behalf of Energy Michigan, Inc. upon those individuals listed on the attached Service List by email at their last known addresses.

____
Monica Robinson

SERVICE LIST U-17032

Richard J. Aaron
David R. Whitfield
Warner Norcross & Judd, LLP
120 N. Washington Sq., Ste. 410
Lansing, MI 48933
raaron@wnj.com
dwhitfield@wnj.com

Hon. Sharon L. Feldman
Administrative Law Judge
Michigan Public Service Comm.
6545 Mercantile Way, Ste. 14
P.O. Box 30221
Lansing, MI 48909
feldmans@michigan.gov

MPSC Staff
Anne Uitvlugt
Amit T. Singh
6545 Mercantile Way, #15
Lansing, MI 48909
uitvlugta@michigan.gov
singha9@michigan.gov

FirstEnergy Solutions Corp.
Laura Chappelle
Bruce Goodman
Timothy Lundgren
c/o P.O. Box 352
Grand Rapids, MI 49504
lachappelle@varnumlaw.com
bgoodman@varnumlaw.com
tjlundgren@varnumlaw.com

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Motion to Intervene of the Retail Energy Supply Association via e-mail on each person listed on the Commission's official service list compiled by the Secretary in this proceeding.

Dated in Washington, DC this 14th day of December, 2016.

/s/Elizabeth Whittle___
Elizabeth W. Whittle