STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to open a docket to implement the provisions of Section 6w of 2016 PA 341 for **UPPER PENINSULA POWER COMPANY'S** service territory.	))))))	Case No. U-18254

At the November 30, 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

ORDER

History of Proceedings

In an order issued on January 20, 2017 (January 20 order), the Commission commenced proceedings for the implementation of Section 6w of 2016 PA 341 (Act 341), MCL 460.6w, for DTE Electric Company (DTE Electric) and Consumers Energy Company (Consumers), and set a schedule for related filings.

Subsequently, as a result of rulings by the Federal Energy Regulatory Commission (FERC),[1] the Commission issued an order on February 28, 2017, (February 28 order) suspending the schedule for the DTE Electric and Consumers proceedings, and adding proceedings for, among others, Upper Peninsula Power Company (UPPCo). In the February 28 order, the Commission observed:

> Unlike the January 20 orders, this order contains captions for Upper Michigan Energy Resources Corporation (UMERC), Upper Peninsula Power Company (UPPCo), and Cloverland Electric Cooperative (Cloverland), each of which currently serves or has choice customers enrolled for service. . . . Case No. U-18254 is being opened for UPPCo. . . . The January 20 orders did not apply to UMERC, UPPCo, or Cloverland because the application filed in Docket No. ER17-284-000 by MISO for approval of its CRS included provisions that would have exempted the choice loads of the utilities serving customers in Michigan's Upper Peninsula because those loads did not meet MISO's materiality threshold. However, nothing in Section 6w(2) of Act 341 excludes any AES loads in Michigan from operation of the [state reliability mechanism] SRM. Accordingly, the Commission seeks comment on whether to move forward at this time to establish an SRM for these utilities.

February 28 order, p. 4.

On May 31, 2017, the Commission issued a scheduling order directing UPPCo to appear at an initial prehearing conference and setting dates for intervention. On June 28, 2017, Administrative Law Judge Suzanne D. Sonneborn (ALJ) held a prehearing conference, at which intervenor status was granted to Constellation NewEnergy, Inc. and Constellation Energy Services Inc., (together,

[1] On February 2, 2017, the FERC issued an order (February 2 order) rejecting the Midcontinent Independent System Operator, Inc.'s (MISO) Competitive Retail Solution (CRS) tariff filing in Docket No. ER17-284-000. The FERC determined that the Forward Resource Auction (FRA) proposed by MISO, which would apply to a small amount of load within MISO and would occur more than three years prior to MISO's existing Planning Resource Auction (PRA), would bifurcate the MISO capacity market and have potential adverse impacts on price. February 2 order, p. 2. The FERC did not expressly comment on the Prevailing State Compensation Mechanism (PSCM) proposal that was set forth in MISO'S CRS filing. Notwithstanding, the Commission understands that the PSCM was also rejected in the February 2 order. The Commission eventually concluded that further efforts to implement Section 6w(1) of Act 341 were no longer required. March 10, 2017 order, p. 18 (March 10 order).

CNE), the Michigan Electric Cooperative Association (MECA), and Verso Corporation.[2] The Commission Staff (Staff) also participated. The ALJ set a schedule that provided for UPPCo's application filing and for a completion date to allow the Commission to read the record and issue an order no later than December 1, 2017, as required by Section 6w. In accordance with that schedule, on July 31, 2017, UPPCo filed its application, along with supporting testimony and exhibits, for an SRM charge under Section 6w of Act 341.

On May 11, 2017, the Commission issued an order clarifying the procedure for establishing the format of the capacity demonstration process and seeking comments on three threshold issues.

On June 15, 2017, the Commission issued an order in this docket and in Case No. U-18197, addressing the threshold questions that had been put out for comment regarding the capacity demonstration process.

On September 1, 2017, testimony and exhibits were filed by the Staff, MECA, and CNE. On September 14, 2017, rebuttal testimony and exhibits were filed by UPPCo. An evidentiary hearing was held on September 21, 2017. On October 12, 2017, UPPCo, the Staff, CNE and MECA filed initial briefs. On October 24, 2017, the same parties filed reply briefs. The record consists of 103 pages of transcript and nine exhibits admitted into evidence.

Background

MCL 460.6w(12)(h) defines the SRM[3] as "a plan adopted by the commission in the absence of a [PSCM] to ensure reliability of the electric grid in this state consistent with" MCL 460.6w(8).

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[2] Verso Corporation did not participate further in this proceeding.

[3] The final sentence of Section 6w(2) refers to establishment of a "state reliability charge" in the same manner as a "capacity charge" under Section 6w(3). The remainder of Section 6w refers to the state reliability mechanism or SRM. "SRM charge" or "capacity charge" are used interchangeably throughout this order to refer to the state reliability charge.

Pertinent subsections of MCL 460.6w related to the SRM and the capacity obligations and process are as follows:

> (2) . . . If, by September 30, 2017, the Federal Energy Regulatory Commission does not put into effect a resource adequacy tariff that includes a capacity forward auction or a prevailing state compensation mechanism, then the commission shall establish a state reliability mechanism under subsection (8). The commission may commence a proceeding before October 1 if the commission believes orderly administration would be enabled by doing so. If the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year. A state reliability charge must be established in the same manner as a capacity charge under subsection (3) and be determined consistent with subsection (8).
>
> (3) After the effective date of the amendatory act that added section 6t, the commission shall establish a capacity charge as provided in this section. A determination of a capacity charge must be conducted as a contested case pursuant to chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287, after providing interested persons with notice and a reasonable opportunity for a full and complete hearing and conclude by December 1 of each year. The commission shall allow intervention by interested persons, alternative electric suppliers, and customers of alternative electric suppliers and the utility under consideration. The commission shall provide notice to the public of the single capacity charge as determined for each territory. No new capacity charge is required to be paid before June 1, 2018. The capacity charge must be applied to alternative electric load that is not exempt as set forth under subsections (6) and (7). If the commission elects to implement a capacity forward auction for this state as set forth in subsection (1) or (2), then a capacity charge shall not apply beginning in the first year that the capacity forward auction for this state is effective. In order to ensure that noncapacity electric generation services are not included in the capacity charge, in determining the capacity charge, the commission shall do both of the following and ensure that the resulting capacity charge does not differ for full service load and alternative electric supplier load:
>
> (a) For the applicable term of the capacity charge, include the capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.
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> (b) For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization and the projected revenues, net of projected fuel costs, from all of the following:

(i) All energy market sales.

(ii) Off-system energy sales.

(iii) Ancillary services sales.

(iv) Energy sales under unit-specific bilateral contracts.

(4) The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year.

(5) Not less than once every year, the commission shall review or amend the capacity charge in all subsequent rate cases, power supply cost recovery cases, or separate proceedings established for that purpose.

(6) A capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an alternative electric supplier can demonstrate that it can meet its capacity obligations through owned or contractual rights to any resource that the appropriate independent system operator allows to meet the capacity obligation of the electric provider. The preceding sentence shall not be applied in any way that conflicts with a federal resource adequacy tariff, when applicable. Any electric provider that has previously demonstrated that it can meet all or a portion of its capacity obligations shall give notice to the commission by September 1 of the year 4 years before the beginning of the applicable planning year if it does not expect to meet that capacity obligation and instead expects to pay a capacity charge. The capacity charge in the utility service territory must be paid for the portion of its load taking service from the alternative electric supplier not covered by capacity as set forth in this subsection during the period that any such capacity charge is effective.

(7) An electric provider shall provide capacity to meet the capacity obligation for the portion of that load taking service from an alternative electric supplier in the electric provider's service territory that is covered by the capacity charge during the period that any such capacity charge is effective. The alternative electric supplier has the obligation to provide capacity for the portion of the load for which the alternative electric supplier has demonstrated an ability to meet its capacity obligations. If an alternative electric supplier ceases to provide service for a portion or all of its load, it shall allow, at a cost no higher than the determined capacity charge, the assignment of any right to that capacity in the applicable planning year to whatever electric provider accepts that load.

(8) If a state reliability mechanism is required to be established under subsection (2), the commission shall do all of the following:

(a) Require, by December 1 of each year, that each electric utility demonstrate to the commission, in a format determined by the commission, that for the planning year beginning 4 years after the beginning of the current planning year, the electric utility owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable.

(b) Require, by the seventh business day of February each year, that each alternative electric supplier, cooperative electric utility, or municipally owned electric utility demonstrate to the commission, in a format determined by the commission, that for the planning year beginning 4 years after the beginning of the current planning year, the alternative electric supplier, cooperative electric utility, or municipally owned electric utility owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable. One or more municipally owned electric utilities may aggregate their capacity resources that are located in the same local resource zone to meet the requirements of this subdivision. One or more cooperative electric utilities may aggregate their capacity resources that are located in the same local resource zone to meet the requirements of this subdivision. A cooperative or municipally owned electric utility may meet the requirements of this subdivision through any resource, including a resource acquired through a capacity forward auction, that the appropriate independent system operator allows to qualify for meeting the local clearing requirement. A cooperative or municipally owned electric utility's payment of an auction price related to a capacity deficiency as part of a capacity forward auction conducted by the appropriate independent system operator does not by itself satisfy the resource adequacy requirements of this section unless the appropriate independent system operator can directly tie that provider's payment to a capacity resource that meets the requirements of this subsection. By the seventh business day of February in 2018, an alternative electric supplier shall demonstrate to the commission, in a format determined by the commission, that for the planning year beginning June 1, 2018, and the subsequent 3 planning years, the alternative electric supplier owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable. If the commission finds an electric provider has failed to demonstrate it can meet a portion or all of its capacity obligation, the commission shall do all of the following:

(i) For alternative electric load, require the payment of a capacity charge that is determined, assessed, and applied in the same manner as under subsection (3) for that portion of the load not covered as set forth in subsections (6) and (7). If a capacity charge is required to be paid under this subdivision in the planning year beginning June 1, 2018 or any of the 3 subsequent planning years, the capacity charge is applicable for each of those planning years.

(ii) For a cooperative or municipally owned electric utility, recommend to the attorney general that suit be brought consistent with the provisions of subsection (9) to require that procurement.

(iii) For an electric utility, require any audits and reporting as the commission considers necessary to determine if sufficient capacity is procured. If an electric utility fails to meet its capacity obligations, the commission may assess appropriate and reasonable fines, penalties, and customer refunds under this act.

(c) In order to determine the capacity obligations, request that the appropriate independent system operator provide technical assistance in determining the local clearing requirement and planning reserve margin requirement. If the appropriate independent system operator declines, or has not made a determination by October 1 of that year, the commission shall set any required local clearing requirement and planning reserve margin requirement, consistent with federal reliability requirements.

(d) In order to determine if resources put forward will meet such federal reliability requirements, request technical assistance from the appropriate independent system operator to assist with assessing resources to ensure that any resources will meet federal reliability requirements. If the technical assistance is rendered, the commission shall accept the appropriate independent system operator's determinations unless it finds adequate justification to deviate from the determinations related to the qualification of resources. If the appropriate independent system operator declines, or has not made a determination by February 28, the commission shall make those determinations. . . .

* * *

(12) As used in this section:

(a) "Appropriate independent system operator" means the Midcontinent Independent System Operator.

* * *

(c) "Electric provider" means any of the following:
(i) Any person or entity that is regulated by the commission for the purpose of selling electricity to retail customers in this state.
(ii) A municipally owned electric utility in this state.
(iii) A cooperative electric utility in this state.
(iv) An alternative electric supplier licensed under section 10a.

(d) "Local clearing requirement" means the amount of capacity resources required to be in the local resource zone in which the electric provider's demand is served to ensure reliability in that zone as determined by the appropriate independent system operator for the local resource zone in which the electric provider's demand is served and by the commission under subsection (8).

(e) “Planning reserve margin requirement” means the amount of capacity equal to the forecasted coincident peak demand that occurs when the appropriate independent system operator footprint peak demand occurs plus a reserve margin that meets an acceptable loss of load expectation as set by the commission or the appropriate independent system operator under subsection (8).

* * *

(h) “State reliability mechanism” means a plan adopted by the commission in the absence of a prevailing state compensation mechanism to ensure reliability of the electric grid in this state consistent with subsection (8).

Thus, Section 6w of Act 341 requires each electric utility, alternative electric supplier (AES), cooperative electric utility, and municipally-owned electric utility to demonstrate to the Commission, in a format determined by the Commission, that the load serving entity (LSE or electric provider) owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or by the Commission, as applicable. In the event an AES cannot make the required capacity showing (or elects not to), Section 6w requires that an SRM capacity charge be assessed, to be determined by the Commission, with the associated capacity for such AES customers provided by the incumbent utility. Section 6w established a new framework for resource adequacy in Michigan – that is, ensuring electric providers can meet customers’ electricity needs over the long term even during periods of high electricity consumption or when power plants or transmission lines unexpectedly go out of service. Act 341 went into effect on April 20, 2017.

Pursuant to a series of orders issued in Case No. U-18197 and the March 10 order in this matter, the Staff held a number of technical conferences for the purpose of addressing the procedures and requirements for demonstrating capacity. The Commission engaged stakeholders, with opportunities to provide comments and positions, and also opened dockets in this case and in four others, for the electric providers with choice load potentially affected by the SRM charge requirement of Section 6w.

Under the Section 6w framework, the Commission must determine the capacity obligations for individual electric providers and create a process to evaluate whether such obligations are met. Section 6w provides remedies in instances when an electric provider is unable to demonstrate it has procured adequate capacity to cover its load, including allowing for uncovered AES load to be assessed a capacity charge determined by the Commission and paid to the incumbent utility in exchange for meeting that load's capacity obligations. Special provisions exist for electric utilities, municipally-owned utilities, and electric cooperatives that fail to meet the Section 6w capacity obligations. Whether any capacity charge is actually imposed will be determined after February 9, 2018, when AESs make their capacity demonstrations. However, under Section 6w(3), the capacity charge must be established by the Commission after a contested case by December 1 of each year, and the charge may not go into effect prior to June 1, 2018.

In the September 15 order, the Commission adopted a timeline and procedures for the capacity demonstration process referred to in Section 6w(6) and (8). In the September 15, 2017 order in Case No. U-18441, the Commission opened the docket that will be the repository for all of the electric providers' filings for the initial demonstrations for planning years 2018-2021. Under the approved timeline, the Staff will file a memo in that docket indicating its determination on each electric provider's demonstration by March 6, 2018. Show cause proceedings shall be initiated if an individual LSE does not appear to have sufficient capacity based on the Staff's assessment. Such a proceeding will provide an opportunity for parties to present evidence on whether the electric provider has failed to demonstrate that it can meet a portion or all of its capacity obligations, thereby triggering Commission action as set forth in Section 6w(8)(b)(i). The instant order will determine the capacity charge associated with load in UPPCo's service territory. Whether the charge is levied on any retail open access (ROA or choice) customers will be determined by the outcome of any orders to show cause issued after March 6, 2018, for AESs serving load in UPPCo's service territory.

<u>Review of the Record</u>

Aaron L. Wallin, Manager of Power Supply and Resource Planning for UPPCo, sponsored Exhibit A-1, which shows the company's capacity resources and production costs associated with UPPCo's proposed SRM charge for any AES that is unable to meet its capacity demonstration. 2 Tr 22. Mr. Wallin explained that UPPCo owns two fuel oil generators and four hydroelectric dams with a total unforced capacity (UCAP) of 47.8 megawatts (MW). In addition, Mr. Wallin testified that UPPCo currently has a full requirements contract with Wisconsin Public Service Corporation (WPS Corp) for 40 to 65 MW, noting that "[t]he applicable MW nomination associated with the total cost of capacity from the 2016 Cost of Service Study is 49 MWs." 2 Tr 23. However, Mr. Wallin explained that the WPS Corp contract will end on January 1, 2018, and that this capacity will need to be replaced. Mr. Wallin stated that UPPCo had secured 25 MW of capacity for the 2017-2018 through the 2019-2020 planning years. Mr. Wallin averred that this capacity, along with one MW of capacity from two small hydro facilities, should suffice to meet UPPCo's planning reserve margin requirement (PRMR) through May 2020. 2 Tr 23-24.

Mr. Wallin testified that, in accordance with MCL 460.6w(3)(b)(i), he deducted revenue from energy sales from UPPCo's generation resources, net of fuel, and ancillary service sales. Mr. Wallin noted that UPPCo is a net purchaser of energy in the MISO market, and does not have any contract sales. 2 Tr 24.

Mr. Wallin explained that UPPCo is proposing an SRM charge of $340,024.60/MW-year, based on the total cost of capacity net of energy market sales from the capacity resources of $35,040,245.00, minus revenue from energy market sales of $1,637,898.72 and ancillary service sales of $147,940.14, to arrive at a total cost of capacity of $33,254,406.14. Mr. Wallin then divided this amount by 97.8 MW, the capacity credit assigned to UPPCo by MISO. 2 Tr 25.

Mr. Wallin provided an example of how the capacity charge would be assessed:

> As set forth in MCL 460.6w(6), the capacity charge in the utility service territory must be paid for the portion of its load taking service from the alternative electric supplier not covered by capacity during the period that any such capacity charge is effective. Therefore, if an AES has a capacity obligation of 10MWs but only demonstrates the ability [to] meet 5MWs of its obligation, UPPCO would charge the AES for 5MWs at an annual rate of $340,024.60/MW-year.

Id. Mr. Wallin added that, under MCL 460.6w(8)(b)(i), if a capacity charge is required to be paid in 2018, or in any of the following three planning years, then the charge must be applied for all four years.

Mr. Wallin opined that the capacity charge should be assessed on the AES and not the customer because it is the AES, and not the customer, that is required to make the capacity demonstration. Mr. Wallin further noted that an AES that cannot make the capacity demonstration likely has a means to pass additional capacity charges to customers through its contracts. 2 Tr 26.

Mr. Wallin suggested that UPPCo would facilitate the transfer of capacity to the AES through the purchase and transfer of zonal resource credits (ZRCs) via the MISO Module E Capacity Tracking (MECT) tool prior to the MISO deadline for submitting a fixed resource adequacy plan (FRAP). With respect to the true-up of actual with projected revenues under MCL 460.6w(4) Mr. Wallin proposed that: (1) for energy market sales, UPPCo will provide an hourly comparison between the projected energy market sales revenue and the actual revenue received from MISO, less fuel costs; and (2) for ancillary services sales, UPPCo will also provide an hourly comparison of ancillary services sales and actual revenue received from MISO, as part of its annual SRM capacity cost filing. Any difference between the forecasted revenue and actual revenue will be rolled into the SRM capacity charge for the next year. 2 Tr 26-27.

Natasha L. Wonch, Rate Analyst for UPPCo, sponsored Exhibit A-2, which provides the total integrated system capacity related costs from the cost of service study (COSS) approved in the September 8, 2016 order in Case No. U-17895, UPPCo's most recently approved rate case. Ms. Wonch explained that the capacity-related costs are the production demand costs for each rate class as determined by the COSS. 2 Tr 31-32. Ms. Wonch further testified that UPPCo's retail access service tariff was updated to include the SRM capacity charge. 2 Tr 32, Exhibit A-3.

Nicholas M. Revere, Manager of the Rates and Tariff Section of the Commission's Regulated Energy Division, presented the Staff's calculation of the capacity charge. He opined that the appropriate cost of capacity is the cost of new entry (CONE), or the cost to build a combustion turbine (CT). According to Mr. Revere, "the difference between the cost to build a CT and any other type of plant is the capital cost expended to produce lower energy costs. In Staff's opinion, this cost should properly be considered an energy cost." 2 Tr 60.

Mr. Revere testified that UPPCo inappropriately included non-capacity related costs in its calculation, noting, for example, that UPPCo included one third of fuel costs as capacity costs. In addition, Mr. Revere testified that UPPCo included some administrative and general (A&G) costs and income taxes that are classified as production demand related, but that are not directly incurred to provide capacity and thus should not be included in calculating the cost of capacity. 2 Tr 60-61.

Mr. Revere stated that using UPPCo's most recently approved COSS, the Staff identified all costs currently allocated using the production cost as capacity related, noting that the current production cost allocator of 12 coincident peak (CP) 75/25 recognizes that 75% of costs are capacity related. The Staff then divided those costs identified as directly incurred to provide capacity service into capacity and non-capacity-related categories using the 75/25 split.

Mr. Revere continued:

> An alternative methodology is to apply a percentage to all production demand classified costs at the percentage necessary to make the resulting amount equal to CONE or some other measure of the value of capacity, as determined by the Commission. This would treat all costs in excess of CONE (or the Commission's chosen value of capacity) as non-capacity-related costs. Should the Commission determine such a method is more appropriate, Staff recommends that the levelized per year cost of a CT resulting from the Company's [Public Utility Regulatory Policies Act] PURPA case, U-18094, be utilized. This would provide consistency in the Commission's determination of the value of capacity.

2 Tr 61-62.

In addition, in light of the limited amount of time the Staff had to review UPPCo's calculations, Mr. Revere recommended that the Commission should require UPPCo, in its next general rate case, to file its COSS consistent with the decisions in Case Nos. U-18239 and U-18248, as well as the determinations in this order. Mr. Revere opined that this approach would ensure consistency with respect to the calculation of capacity costs. 2 Tr 62.

Mr. Revere stated that the Staff interprets Section 6w to require a single capacity charge applied to similarly-situated ROA and full-service customers, allowing for collection of class cost responsibility from that class. With respect to the issue of how to align the collection of costs with customers' contributions to the need for capacity, Mr. Revere noted two difficulties. First, he stated that billing according to the measure of contribution is effectively impossible, and randomness may move the peak. Second, customers would not be able to determine when the peak hours would occur because they are not known until after the fact. To address these issues, he suggested using a proxy such as on-peak demand, which applies a charge to the highest hour of demand a customer places on the system during on-peak hours of the billing month. However, he noted that for smaller classes, the proxy measure would still be problematic. He opined that for classes with large numbers of diverse customers, on-peak kilowatt-hours (kWh) is the best starting point for billing these costs, noting:

> Using the entire year incorporates those months included in the calculation of the 12CP allocator, which is used to determine cost responsibility for these capacity-related costs. At this point, narrowing the number of hours charged beyond this on-peak period unreasonably increases the risk of reaching an undesirable result. As classes contain fewer customers with more usage, one approaches the assumed perfect case of a one customer class, where any measure will result in the same cost responsibility to the customer. However, as the Company currently lacks the ability to charge most non-demand billed customers on the basis of on-peak energy, Staff proposes a charge based on annual kWh for the smaller schedules for which the capability to charge on an on-peak basis is lacking, and a charge based on annual on-peak energy for the smaller schedules for which the Company has the ability to charge on-peak rates. Staff proposes a charge based on on-peak demand for classes that currently have such charges. However, if the Commission decides the costs must be billed the same to all classes, an annual kWh charge should be utilized. The result should be similar for the larger customers, and more accurate for the smaller.

2 Tr 65-66.

In sum, Mr. Revere recommended that capacity related costs be collected through annual kWh charges for rate schedules without demand charges that cannot be charged on-peak rates, on-peak kWh charges for schedules without demand charges that can be charged on-peak, and through on-peak kW charges for rate schedules with demand charges as shown in Exhibit S-1.2. If the Commission decides that all customers must pay the same charge, then he recommends that the charge be collected through a uniform annual kWh total charge calculated by dividing total capacity costs by total kWh. 2 Tr 66.

Mr. Revere disagreed with UPPCo’s proposal to maintain its rates and tariffs for full-service customers, observing that Section 6w(3) requires the capacity charge to be the same for both bundled and choice customers. Accordingly, Mr. Revere concluded that the capacity charge must apply to both groups of customers.

Mr. Revere stated that Section 6w(3)(b) requires only a very limited reconciliation of the projected net revenues used in the calculation of the SRM charge to the actual net revenues, and the difference is reflected in the charge for the next year. He noted that capacity-related costs associated with power purchase agreements (PPAs) are reconciled as part of the PSCR process, and opined that the best way to reconcile capacity costs with SRM charges is through the PSCR reconciliation.

> It would be reasonable to assume that the amount of Capacity Charge revenue associated with PPA capacity costs is proportionate to the amount of PPA capacity costs included as part of the calculation of the Capacity Charge. For example, if PPA Capacity costs are 5% of the total capacity-related costs used to calculate the Capacity Charge, 5% of the revenues received from that charge should be considered revenues to cover those same costs. Any difference between the collected revenue so calculated and the actual PPA capacity costs should be included in the calculation of the next year's Capacity Charge.

2 Tr 68.

Gradon Haehnel, UPPCo's Director of Regulatory Affairs, disputed Mr. Revere's claim that UPPCo had not properly identified capacity-related costs in its direct case, noting that the capacity costs were based on the company's approved COSS. Mr. Haehnel opined that if the Staff's position were adopted, "it would revise and/or redefine the Company currently approved COSS without legal or evidentiary support." 2 Tr 37. Mr. Haehnel explained that capacity-related costs (i.e., production demand costs) are already identified through cost classification and allocation, including the proper production cost allocator in the COSS. Mr. Haehnel continued, explaining in some detail the steps for cost functionalization, classification, and allocation that led to the proper differentiation between capacity-related and non-capacity-related costs. 2 Tr 38-40.

Mr. Haehnel also took issue with Mr. Revere's contention that the cost of capacity is CONE, claiming that adopting such an approach would not ensure that the cost of capacity for both full-service and choice customers would be equal, thus violating the requirement under MCL

460.6w(3) that capacity charges be the same for both types of customers. 2 Tr 41. Mr. Haehnel further criticized the Staff for failing to provide a definition of capacity versus non-capacity costs, and he pointed to the method approved in Case No. U-17032 for establishing Indiana Michigan Power Company's (I&M's) state compensation mechanism, noting that nothing in Section 6w changes the definition of capacity-related costs. 2 Tr 45-48.

Eric W. Stocking, an Economic Specialist in the Commission's Financial Analysis and Audit Division,[4] testified that, consistent with Section 6w(6), the SRM charge "shall not be assessed" for any portion of the capacity obligation for a planning year (PY) during which the AES demonstrates an ability to meet. Mr. Stocking maintained that the capacity charge may only be assessed for AES load (for any PY) for which the AES was unable to demonstrate an ability to meet. "For any years in which the AES is able to demonstrate that it has owned or contracted resources that satisfy its capacity obligations, no capacity charge should be levied onto that particular AES's customers." 2 Tr 74.

Mr. Stocking agreed with Mr. Wallin that, under Section 6w(8), in the initial four-year period beginning June 1, 2018, any portion of AES load that is not supported by a satisfactory capacity demonstration in any one of those first four PYs would be subject to the charge for those four years, and that, beginning with PY five and thereafter the AES may make the demonstration on an annual basis, and customers would be subject to the charge on an annual basis as well.
Mr. Stocking indicated that the utility may have no other choice but to procure resources from the PRA in the short term and noted that this would be no different from how the affected AES would

[4] The Commission notes that Mr. Stocking left his employment with the Commission several months after filing his testimony in this proceeding. It is the Commission's understanding that he is now employed by UPPCo.

have procured the capacity. Mr. Stocking added that this interpretation was consistent with Sections 6w(6) and 6w(8)(b)(i).

With respect to UPPCo's proposal to impose the capacity charge, when applicable, on the AES rather than the customer, Mr. Stocking pointed out that because the capacity charge is a retail charge, it should be imposed on the customer rather than the AES. Mr. Stocking opined that UPPCo's proposal conflicts with MCL 460.6w(3), which requires that the capacity charge for both retail and choice customers must be equal. According to Mr. Stocking:

> [T]he Commission can only ensure that the "resulting capacity charge does not differ" if it sets the rate. The Commission may not set the rates an alternative electric supplier charges to its "load," i.e. customers. See MCL 460.6w(3). However, the Commission does set the rates public utilities may charge their ROA customers, and in so doing, may ensure that the capacity charge for both bundled and ROA customers do not differ.

2 Tr 76.

In response, Mr. Haehnel reiterated that because UPPCo is acting as supplier of last resort for an AES that cannot demonstrate that it has sufficient capacity, the proper entity to be assessed a capacity charge is the AES, noting that the AES can then pass the capacity charge on to its customers. However, in the event that the Commission decides to bill the choice customer, rather than the AES, Mr. Haehnel recommended that UPPCo's original proposal be modified in the following manner:

> Step 1: By consistently applying the ratio of capacity to non-capacity charges across all rate classes, UPPCO can derive a bifurcated value of power supply on an energy (kWh) or demand (kW) basis. Step 2: To account for the adjustments made by Mr. Wallin regarding energy market sales on a rate class level, UPPCO proposes to proportionally distribute the energy market sales based on the respective value of each class's non-capacity charges. Step 3: The tariff modifications would not only define the terms of capacity power supply and non-capacity power supply, but also clearly illustrate, in table form, what power supply costs are paid for by full service load and alternative energy supplier load customers.

2 Tr 51.

Thomas King, Director of Regulation and Policy for Wolverine Power Supply Cooperative, testified on behalf of MECA. Mr. King opined that, in the event that the capacity charge set in this proceeding is required to be assessed, the payment obligation should be imposed on the AES, not the choice customer. Mr. King explained that an AES has several options for procuring capacity including generation ownership, PPAs, and capacity auctions. Mr. King averred that the decision to procure capacity or rely on the utility is made by the AES and not the customer. Mr. King observed that customers are end-users of energy and have no ability to provide information for capacity demonstration purposes, serve their own load, or obtain capacity independently. 2 Tr 81.

Mr. King explained that AESs currently pay distribution utilities for billing services, and the same method could be used to assess AESs subject to the SRM charge. Mr. King emphasized that an AES is only responsible for the charge in the event that the Commission has determined that the AES was deficient in its capacity demonstration. In addition, Mr. King stated that he agrees with UPPCo that the initial capacity demonstration requires a demonstration of sufficient capacity for the first four years, and thereafter, a demonstration need only be made for one planning year. Mr. King further indicated that he agreed with UPPCo that a capacity charge can only be assessed for years covered by a particular capacity demonstration. 2 Tr 82.

Laura T. W. Olive, Ph.D., Senior Consultant at National Economic Research Associates, Inc., testified on behalf of CNE. Dr. Olive concluded that the SRM charge is unique to Michigan's approach to electric choice, and that the SRM charge "seeks to reflect the portion of the utility's regulated costs required to meet peak system load and will apply to both utility and AES customers." 2 Tr 86. Dr. Olive further opined that it was important to distinguish between capacity costs and energy costs when developing the SRM charge and that UPPCo's proposed method reflects the company's embedded costs but not the costs of acquiring additional capacity to potentially serve the needs of AES load. 2 Tr 87.

Dr. Olive testified that Section 6w requires incumbent regulated utilities to include the 10% choice customers in their capacity plans, and that the capacity charge will be new and incremental for ROA customers. Dr. Olive suggests that UPPCo could have used a planning model that reflects its going-forward capacity-only costs during the term of the capacity charge. Instead, UPPCo proposed to use its production demand costs from its most recent COSS as capacity, and then subtract energy market sales and ancillary service sales from this amount to derive a capacity charge. Dr. Olive opined that UPPCo's method results in a capacity charge that is not consistent with the requirements of Section 6w. 2 Tr 88-89. According to Dr. Olive, UPPCo's proposed method is improper because:

> [UPPCo's] SRM capacity charge does not address the issue that Section 6w seeks to cure. The SRM capacity charge should be established such that it creates a mechanism to ensure reliability with sufficient capacity resources at the "forecasted coincident peak demand" plus a reserve margin. UPPCO has simply taken a portion of the expenses that make up its cost of service and re-classified them as capacity costs. Thus, the capacity charges do not reflect a market based value for capacity but simply represent UPPCO's embedded costs. UPPCO's cost of service study serves a purpose in the calculation of rates, but not the purpose of the SRM capacity charge which is to address a concern about reliability at the peak.

2 Tr 89 (footnotes omitted). Dr. Olive testified that it is necessary to consider contribution to peak load when computing the SRM charge because the purpose of the charge is to ensure system reliability on-peak. According to Dr. Olive, "There is nothing forward-looking, planning-based, or market-based about UPPCO's proposed SRM capacity charge. It is a number that reflects only UPPCO's embedded cost of service." *Id.*

Dr. Olive explained that nevertheless, there is a way to use embedded costs for calculating the SRM charge, citing Chapter 4 of the National Association of Regulatory Utility Commissioners

Electric Utility Cost Allocation Manual (NARUC Manual). Dr. Olive testified that energy weighting could be used to allocate production costs and derive an SRM capacity charge. Accordingly, Dr. Olive recommended the "Average Excess" method that:

> allocates production plant costs to average loads—using only the "excess" to allocate costs based on the difference between average loads (that does not include AES customers) and the maximum demand (that would include AES customers). The result of this calculation is such that AES customers pay only a pro rata share of the maximum demand. Performing the calculation in an objective fashion requires only average and peak-load measures for each class of service.

2 Tr 91. Using the average excess method, Dr. Olive calculated a capacity charge of $241/MW-day. Alternatively, Dr. Olive recommended capping the SRM charge at the annual MISO CONE, which, for Zone 2 is $95,230/MW-year or $260.90/MW-day. Dr. Olive testified that using CONE is reasonable because it "represents an independent, forward-looking value for the cost of new entry of capacity into Zone 2 that has been accepted by the FERC as such." 2 Tr 94.

In rebuttal to Dr. Olive, Mr. Haehnel indicated that while he agreed with the CNE's use of fully-embedded costs in the first part of the calculation, he contended that the use of CONE in the second part of the calculation results in full-service customers paying more than choice customers for capacity because "the average and access [sic] method, . . . accounts only for the 'excess' (or maximum demand) reflective of the inclusion of alternative electric supplier load, resulting in the AES only paying for its pro rata share." 2 Tr 49.

<u>Positions of the Parties</u>

Consistent with the Staff's position, UPPCo points out that subsection (8)(b)(i) of Section 6w states that, in the event that an AES cannot demonstrate sufficient capacity in 2018, or any of the subsequent three years, a capacity charge must be imposed, and the charge should be levied for the entire four-year period. UPPCo also does not oppose the Staff's interpretation that after the 2021-

2022 planning year, the term of the capacity charge should be one year. UPPCo also proposes a true-up mechanism that would compare forecasted revenue from energy market sales and ancillary service sales to actual revenue from these sales. And, UPPCo concurs with the Staff's recommendation that any differences between the revenue collected and actual costs should be carried forward and included in the calculation of the next year's capacity charge.

UPPCo contends that its calculation method for the SRM charge is consistent with MCL 460.6w(3). UPPCo explains that it began with its total system integrated capacity costs identified in its most recently approved COSS and then determined its capacity-related costs as the production demand costs calculated for each rate class. Consistent with Section 6w(8), UPPCo then made adjustments for energy market sales, and ancillary services sales to arrive at a total cost of capacity of $33,354,406.14. This amount, divided by the capacity credit of 97.8 MW, equals a capacity charge of $304,024.60/MW-year.

UPPCo criticizes the Staff's and CNE's reliance on CONE as inconsistent with the company's actual capacity-related generation costs and thus in conflict with Section 6w(3)(a). UPPCo further points out that the Commission rejected the Staff's use of a proxy CT (on which CONE is based) in the company's recent avoided cost case, on grounds that a proxy approach might not be appropriate for UPPCo. And, UPPCo contends that the Staff's critique of the company's calculation was speculative, based on approximations only, and therefore cannot be considered substantial evidence. UPPCo also takes issue with the Staff's use of the 75/25 production cost allocator, arguing that "[t]his proposal . . . is not consistent with well-established ratemaking principles as the 75/25 methodology is not (and has never been) used to determine what constitutes a capacity production cost." UPPCo's initial brief, p. 8. Moreover, UPPCo points out that the Staff's proposal here is incompatible with the Staff's support for the method used for determining capacity charges in Case No. U-17032. UPPCo avers that the basic method it proposes in this case is the same as was approved in Case No. U-17032.

UPPCo recommends that the AES be required to pay the capacity charge, in the event that the AES does not make the capacity demonstration. UPPCo points to Section 6w(8) which requires the utility to provide back-up capacity to the AES. According to UPPCo, "[t]his is no different than if an AES were to purchase capacity to meet its obligations from any other counterparty, and is entirely consistent with how the transfer of capacity resources operates within the confines of the MISO resources adequacy construct." UPPCo's initial brief, p. 10. UPPCo further contends that, "[t]here is nothing in Section 6w which reflects a legislative intent to interfere with the existing supplier/customer relationship, and there is certainly nothing in Section 6w which supports Staff's contention that UPPCO must assess the SRM capacity charge directly to the ROA customer to meet Subsection 6w(3)'s mandate[.]" *Id.*

Finally, UPPCo disagrees with the Staff's proposal to require it to file a COSS consistent with the findings in Case Nos. U-18239 and U-18248 in the company's next general rate case. UPPCo maintains that this recommendation is premature because there are no final orders in these cases and, based in the record in this case, UPPCo is unable to evaluate the suitability of this hypothetical COSS.

The Staff argues that the Commission should focus on the statutory scheme and intent of Section 6w, contending, "[t]he goal is to preserve electric reliability in Michigan by making sure that all load-serving entities (LSE) are contributing to resource adequacy." Staff's initial brief, p. 4. The Staff further maintains that the SRM should continue indefinitely, until the statute is changed or repealed.

With respect to calculating the SRM charge, the Staff recommends that the Commission only include costs that are directly related to providing capacity service, and it proposes two methods to identify these costs. The Staff's first suggestion is to determine appropriate production costs and consider only those costs corresponding to the cost of a CT as capacity related, because a CT is the least costly method for producing capacity, and any other method inevitably involves considerations that go beyond capacity. 2 Tr 60. The Staff recommends use of the levelized per-year cost of a CT as determined in UPPCo's recent PURPA case, Case No. U-18094, with the production allocator modified to determine which portion of the costs are capacity related. 2 Tr 61-62. The Staff posits that the demand portion of the production allocator, which is currently set at 75%, could be adjusted (up or down) so that, when applied to UPPCo's approved applicable costs, the result limits the capacity revenue requirement to the cost of a CT unit on a MW/year basis. Staff's initial brief, p. 9. The Staff disagrees with UPPCo's claim that this approach could result in capacity charges that differ for full-service and choice customers. The Staff points out that this incorrectly assumes that all embedded generation costs are capacity-related.

The Staff also proposes an alternative method based on using UPPCo's approved COSS to identify costs incurred to supply capacity. This also begins with identifying appropriate production costs, and then applying the current demand weighting of the production allocator of 75% to those costs. 2 Tr 61. The Staff adds that in light of the limited time it had to review UPPCo's application, the company should be required to file its COSS and rate design, in its next general rate case, consistent with the determinations in this case and Case Nos. U-18239 and U-18248.

The Staff argues that in its filing, UPPCo included costs that were not directly related to supplying capacity service, including fuel, taxes, and A&G expense. The Staff disputes UPPCo's claim that "excluding costs that were classified as production demand related in the Company's most recently approved COSS amounts to improperly changing an approved COSS[,]" noting that in assuming that the meaning of "capacity-related" in Section 6w is the same as "demand-related" in the NARUC manual, UPPCo " begins from an incorrect premise." Staff's initial brief, p. 10, citing 2 Tr 21-22, 37 (footnote omitted). The Staff points out that capacity and demand are two different concepts that UPPCo has conflated and that classifying costs as production demand-related does not necessarily mean the costs are incurred to provide capacity.

With respect to UPPCo's observations about the applicability of Case No. U-17032, the Staff maintains that this case is not the same because the instant case is based on a statute that was enacted long after the Commission decided Case No. U-17032. Moreover, the Staff's position in this case is based on the circumstances presented here and not those in Case No. U-17032.

The Staff recommends that capacity-related costs should be allocated based on the results of the COSS, and that the SRM charge should be the same for similarly-situated full-service and choice customers. The Staff further suggests that the calculation of the SRM charge should be based on on-peak kWh for rate schedules without demand charges that cannot be charged on-peak, on-peak kWh charges for rate schedules without demand charges that can be charged on-peak, and on-peak kW charges for rate schedules with demand charges. The Staff notes that charging directly on 12 CP contribution in any given year is not necessarily representative of contribution to the allocation measure of 12 CP. 2 Tr 63. Also, customers might not know what they would be charged for until after the fact, or the CP might move as customers attempt to avoid contributing. 2 Tr 64. To address this, the Staff recommended on-peak billing demand for demand-billed customers, noting, however, this method may not work as well for classes with large numbers of smaller customers. For these customer classes:

> Staff recommends dealing with this issue by selecting some series of hours likely to become the CP and billing on those hours, as this spreads the cost responsibility over all hours that could potentially become the CP. Staff recommends on-peak kWh, as it balances the competing priorities of sending an effective price signal and not shifting the peak such that the rate no longer reflects the hours likely to become a CP. However, as the Company currently lacks the ability to charge most non-demand billed customers on this basis, Staff proposes the state reliability charge be based on annual kWh for non-demand billed customers for whom the Company lacks the ability to charge based on on-peak kWh. For those non-demand billed customers who can be billed on-peak, Staff recommends on-peak kWh state reliability charges be approved.

Staff's initial brief, p. 15, citing 2 Tr 65-66.

The Staff disagrees with UPPCo, CNE, and MECA that the SRM charge should be paid by the AES rather than customer. According to the Staff, if an AES cannot, or chooses not to, provide sufficient capacity service to a choice customer, then, pursuant to Section 6w(7), the distribution utility steps in and provides state reliability service to the customer. Because this reliability benefit is provided to the customer and not the AES, then the customer should be responsible for paying the charge. The Staff adds that under Section 6w(3), the capacity charge must be equal for both full-service and choice customers. The only way to ensure that outcome is for the incumbent utility to assess the capacity charge on both classes of customers. The Staff adds that the Commission has no authority to set wholesale rates. Thus, if the Commission were to set the capacity charge, and the utility were to recoup these Commission-approved charges from AESs rather than choice customers, it would violate the Federal Power Act (FPA).

Finally, with respect to reconciling the SRM costs and revenues, the Staff recommends that the Commission approve a method whereby energy market sales, off-system energy sales, ancillary services sales, and bi-lateral contract sales (net of fuel costs) are reconciled against the projections of the same items used to calculate the SRM charge. Over- and undercollections would be carried forward as part of the next year's SRM charge. Capacity-related costs associated with PPAs should be reconciled as part of the PSCR process.

CNE urges the Commission to adopt an SRM charge for UPPCo no higher than $260.90/MW-day, based on MISO's CONE for Zone 2. CNE argues that UPPCo's proposal for how to set the SRM charge does not comply with the statute and simply divides up embedded costs in its COSS into capacity and energy. CNE points out that UPPCo's method, which classifies production demand costs from its COSS as capacity costs, results in an SRM charge of $931.57/MW-day. CNE argues that this simply restates embedded cost of service without any attempt to distinguish capacity costs from energy costs. However, CNE maintains that it is possible to use UPPCo's embedded costs to calculate the SRM charge by using the average and excess energy weighting method that CNE proposed.

CNE further argues that the charge should be levied on the AES and not its customers under the clear language of Section 6w(6) which states that "Any electric provider . . . shall give notice . . . if it . . . expects to pay a capacity charge." CNE reasons that AESs should be permitted to manage the charge among their customers on the basis of their entire portfolio and that ROA customers should not be forced into disputes between the AES and the utility. CNE offers that the terms of the ROA tariff could be amended to allow the AES to pay the charge for the relevant portion of its load, and, to avoid double-payment, suggests that the charge be reduced by the PRA clearing price.

MECA concurs with UPPCo that the capacity charge should only be assessed for the period when an AES is deficient. The initial demonstration covers four years, and after that, the demonstration need only be made for one year four years out.

MECA also contends that the capacity charge should be levied on the AES and not the choice customer. Like UPPCo, MECA contends that the plain language of Sections 6w(3) and 6w(6) provides that the capacity charge shall be paid by the "electric provider," which, by definition is not the customer. MECA adds that the language in Section 6w(8) referencing the "portion of its load" means the AES's aggregate load and not individual customer load. MECA also cites Section 6w(7), which mandates that a right to capacity (in the aggregate, and not on an individual customer basis) must be assigned in the event that an AES ceases to serve customers. MECA concludes:

> [T]here is no reasonable support in the statute that a capacity charge should be imposed on the retail customer; rather, the plain language supports UPPCo and MECA's position that any capacity charge should be imposed on an AES. And, because the Commission is a creature of statute, "it possesses only that authority granted by the Legislature." *Consumers Power Co v MPSC*, 460 Mich 148, 155; 596 NW2d 126 (1999). Since the Legislature did not give the Commission the authority to impose the charge on customers, doing so would be improper and unlawful.

MECA's initial brief, p. 8.

MECA further argues that because a choice customer has no control over the AES or its capacity purchases, the customer should not be responsible for the AES's failure to secure sufficient capacity. MECA reiterates that choice customers are not required to make capacity demonstrations; they do not serve their own loads, and they do not "own or control their own capacity 'destiny' (as they cannot procure it and are at the mercy of the LSE)[.]" MECA's initial brief, p. 8. MECA therefore maintains that it is unjust and unreasonable, absent clear statutory authority, to levy the capacity charge directly against a choice customer, noting that an AES can indirectly recoup the SRM charges through provisions in customer contracts.

MECA points out that requiring choice customers to directly pay capacity charges creates an inequity between choice and full-service customers. For example:

> Assume the Choice customer's AES fails to fully meet its capacity obligations. If the customer bears the responsibility to pay, the Choice customer would be obligated to directly pay a capacity charge to UPPCo for the term of the capacity or return to Tariff service. The Tariff service customer, in contrast, is paying rates designed to cover costs, including capacity costs, but can switch to Choice service and not pay a capacity charge, because one or more Choice customers is already stuck paying it – regardless of whether they remain Choice customers.

MECA's initial brief, p. 10. Thus, MECA avers that "a proposal to attach a non-bypassable capacity charge on Choice customers would penalize Choice customers unless they returned to Tariff service. Another Tariff service customer, who switched to Choice would not face such a penalty." MECA's initial brief, p. 12.

Finally, MECA asserts that the SRM charge, if assessed against an AES, does not involve the Commission setting wholesale rates; rather, it is compensation to the LSE for procuring capacity to cover the AES's shortfall. Moreover:

> MECA and UPPCo recognize that the utility-specific capacity charge will be appropriately determined in each LSE's individual SRM case and then set forth in the utility's Retail Open Access ("ROA") Tariff's Retailer Section. The Tariff would then establish an agreement requiring a capacity-short AES to pay a retail capacity charge as one of the terms and conditions. That agreement would be included in one of the many already stated ROA Tariff terms and conditions that the AES must satisfy in order to provide service to the utility's ROA customers.
>
> A proposal that includes a non-bypassable charge would reflect the erroneous assumption that the Choice customer would be paying for actual capacity. They would not. It is fundamental that "[c]ustomers pay for service not the property used to render it. Their payments are not contributions to depreciation or other operating expenses or to capital of the company. By paying bills for service they do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company." *Board of Public Utility Comm'rs v New York Tel Co*, 271 US 23, 32; 46 SCt 363; 70 L Ed 808 (1926). Because the Choice customer will pay for service and not the capacity itself, they have no legal or equitable entitlement to a greater aspect of the capacity benefits. If Choice customers are required to pay the capacity charge, those customers would otherwise have aspects of ownership of the capacity dedicated to serving them. This flaw is avoided when the AES pays the capacity charge for the portion of the utility-provided capacity.

MECA's initial brief, p. 12.

In reply to the Staff, UPPCo argues that the Staff's CT-based method does not comport with the express language of Section 6w(3) which requires the SRM charge to be based on embedded capacity costs contained in "the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resources from a third party[,]" noting that the Commission recently rejected the Staff's proposal to use a CT proxy for setting avoided capacity costs in the company's recent PURPA proceeding, Case No. U-18094. With respect to the Staff's alternative approach, UPPCo reiterates that the Staff's position is inconsistent with customary ratemaking approaches; it lacks substantial and material record support, and it points out that although the Staff references certain portions of the NARUC manual, it failed to enter the manual as an exhibit. UPPCo further contends that the Staff's proposal to classify only 75% of the company's production demand costs as capacity-related will result in the subsidization of choice customers by full-service customers.

UPPCo disagrees with the Staff's claim that the capacity costs identified in Case No. U-17032 are not relevant to this proceeding in light of the later enactment of Act 341. UPPCo contends that, contrary to the Staff's argument, the circumstances of this case are not substantially different than they were when that case was decided, and the Commission should therefore rely on the precedent set in Case No. U-17032 with respect to the appropriate method for determining capacity costs.

UPPCo points out that the Staff is the only party to this proceeding that advocates levying the SRM charge on the customer rather than the AES, and it repeats its arguments concerning how the plain and unambiguous language of the statute requires that the AES, rather than the customer, pay the SRM charge. If the Commission does, however, require UPPCo to charge the customer rather than the AES, UPPCo requests that the Commission adopt its proposal for direct billing AES customers set forth at 2 Tr 51.

In reply to CNE, UPPCo contends that CNE's average and excess method does not comply with Section 6w because it artificially caps the company's capacity costs at the cost of a CT. As a result, UPPCo's full-service customers would effectively be paying more for capacity than choice customers.

The Staff replies that UPPCo misstates the Staff's position with respect to the COSS. According to the Staff, it did use UPPCo's approved COSS, but it did not rely wholly on the classifications in the COSS because they were not intended to identify costs the company incurs to provide capacity service. In addition, contrary to UPPCo's claim, the Staff "specifically identified nearly all of the costs that were not related to the provision of capacity-related service the Company included in its calculation[.]" Staff's reply brief, p. 2. While the Staff concedes that its proposal to characterize 75% of costs allocated by the production allocator as capacity-related is new, the Staff points out that the Commission has never before had to identify capacity costs for UPPCo or under Act 341 and that the method proposed by the Staff is a reasonable means to accomplish this task. In response to CNE's proposal that capacity costs be capped at CONE, the Staff contends that this would violate Section 6w by placing an artificial limit on the cost of capacity.

In response to MECA, UPPCo, and CNE's various arguments concerning the correct entity to pay the SRM charge, the Staff asserts that it is appropriate to charge the choice customer, rather than the AES, for several reasons. First, the Staff posits that reading Section 6w as a whole, it is clear that the legislative intent is to levy the charge on the customer and not the AES, despite some ambiguity in one subsection of the statute. In addition, Section 6w does not only impose an SRM charge; it also mandates that the utility provide capacity service to the choice customer, not the AES, and that the charge to both choice and full-service customers must be equal. Finally, the provision of capacity service by a utility to a customer does not result in some manner of ownership over the capacity supplied, as MECA argues, it is simply providing a service to the customer. Thus, charging an ROA customer for capacity is no different than charging a bundled customer for the same service.

In its reply to the Staff, MECA reiterates that both the statute and logic dictate that the SRM charge should be imposed on the AES and not the customer, again arguing that an SRM charge is not the setting of a rate that might run afoul of the FPA**,** instead it is a charge for a service rendered by a utility to a capacity-short AES. In its reply to UPPCo, CNE again urges the Commission to set the capacity charge no higher than CONE, reiterating that UPPCo's calculation does not reflect the actual cost of capacity. CNE also responds to the Staff, repeating its arguments in favor of assessing the SRM charge on the AES and not the choice customer. Finally, noting that UPPCo and the Staff proposed a true-up mechanism in their briefs. CNE recommends that the Commission defer ruling on the reconciliation process "based on the abstract arguments presented in this proceeding." CNE's reply brief, p. 5.

Discussion

Based on the record and briefing in this proceeding, the following issues require resolution: (1) the term of the capacity charge; (2) the appropriate method for determining the SRM capacity charge for UPPCo in the instant proceeding and in the future; (3) the proper rate design for the SRM charge; and (4) the appropriate entity on which to levy the SRM charge. These issues are addressed *ad seriatim*.

1. Term of the State Reliability Mechanism and Capacity Charge

The Commission agrees with the Staff's position that, absent an expiration date or sunset provision, a statute continues in perpetuity until it is amended or repealed by the Legislature. The other parties to this proceeding do not appear to differ on this point.

The Commission further finds that Section 6w does not limit the term that a charge may remain in place, with the exception of the language in MCL 460.6w(2), which provides that "If the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year." When this language is read *in pari materia* with Section 6w(8)(b)(i), which requires that "If a capacity charge is required to be paid under this subdivision in the planning year beginning June 1, 2018 or any of the 3 subsequent planning years, the capacity charge is applicable for each of those planning years," the Commission concludes that the Legislature intended for the first four consecutive planning years to be treated as a group, and that any charge applicable to any of those first four planning years is also applicable to every other year in the first four planning years. Again, the parties appear to agree on this point.

Other than this limitation applicable to the first four planning years, Section 6w provides no other indication as to the required term of the charge. The Staff and UPPCo seem to agree that a term longer than a year would violate the language of Section 6w(6), which states that a "capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an [AES] can demonstrate that it can meet its capacity obligations." The Commission disagrees. This sentence makes clear that a charge shall not be assessed <u>for</u> a planning year for which an AES can make its demonstration, but it does not say that a charge may not be assessed <u>in</u> a planning year for which an AES can make its demonstration. The Commission concludes therefore that Section 6w allows for a charge to be assessed in a planning year different from the planning year for which the AES failed to show sufficient capacity and for which the utility may recover capacity costs from choice customers.

That said, the statute thereafter focuses on one year at a time, where it requires that "each year" electric utilities, AESs, cooperatives, and municipally-owned utilities shall make their demonstrations "for the planning year beginning 4 years after the beginning of the current planning year." MCL 460.6w(8)(a) and (b). The MISO process is also an annual one. In this context, and bearing in mind that this case is part of the first group of cases setting a capacity charge, the Commission finds that the charge (with the exception of the first four consecutive planning years) should be imposed on an annual basis for a single year. This ensures that the charge comports with the requirements of the statute while avoiding imposition of the charge on the initial group of choice customers for a term that is unduly burdensome.

2. Method for Determining the Capacity Charge

The record in this matter includes a limited number of competing proposals, with marked differences among the proposals. The Commission therefore looks to Section 6w(3), which provides guidance on the method for determining the SRM charge. Section 6w(3)(a) instructs the Commission to begin the calculation of the charge by including "the capacity-related generation costs included in the utility's base rates, surcharges, and [PSCR] factors," regardless of whether those costs result from owned, purchased, or leased resources. Thus, the Commission finds it reasonable to begin with embedded costs contained in UPPCo's full portfolio of resources. Then, under MCL 460.6w(3)(b), certain amounts must be deducted from embedded costs including (net of projected fuel costs) all energy market sales, off-system energy sales, ancillary services sales, and unit-specific bilateral contract sales.[5]

Here, both UPPCo and the Staff (in its COSS-based approach), have attempted to apply the formula set forth in Sections 6w(3)(a) and (b). Specifically, both parties started with embedded costs from the company's most recent COSS, and then subtracted the applicable (current) sales. However, as the Staff correctly points out, the production demand cost from UPPCo's COSS, which was the company's starting point, includes more than just costs associated with providing capacity. Thus, in its calculation, the Staff made adjustments to remove these non-capacity related costs, including fuel, A&G expense, and income tax as is required under Section 6w(3)(a). And, as the Staff explained, this adjustment is not tantamount to changing an approved COSS.

The Commission finds that, based on the requirements of Section 6w(3), the record in this case, and limited to this first SRM charge calculation, it is reasonable to adopt the Staff's method, which involves adjusting the COSS to remove non-capacity related costs as shown in Exhibit S-1.1, with the adjustments for sales provided by UPPCo.

The Commission rejects UPPCo's argument concerning the applicability of Case No. U-17032. As the Staff points out, Case No. U-17032 is distinguishable from this case in many ways. It was required by a tariff approved by PJM, a different regional transmission operator (RTO). In that case, the FERC had previously approved PJM's forward capacity auction tariff; whereas, in this case, the FERC rejected MISO's forward capacity tariff proposals (the CRS and the PSCM) which, if approved, would have prevented the necessity of setting an SRM charge. *See,* n. 1, *supra.* This proceeding takes place pursuant to a state law, Act 341, that did not exist

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[5] UPPCo has no bilateral contract sales. 2 Tr 24.

when Case No. U-17032 was decided. Additionally, the PJM tariff required the setting of a State Compensation Mechanism, not an SRM.

The Commission also finds unpersuasive UPPCo's contention that the Staff's presentation was incomplete, and it therefore cannot be considered substantial and material evidence. As the Staff pointed out, despite the limited amount of time available, the Staff specifically identified nearly all of the costs that were not related to the provision of capacity-related service that UPPCo included in its calculation.[6] The Commission also agrees with the Staff and UPPCo that CNE's proposal to cap the capacity charge at MISO CONE for Zone 2 does not comply with Section 6w.

The Commission nevertheless notes that Sections 6w(3)(a) and (b) differ in that, while (a) relies on "base rates, surcharges, and [PSCR] factors," (b) relies on "projected revenues" net of "projected fuel costs." Thus, (3)(a) refers to embedded costs and (3)(b) refers to forecasted costs. In this proceeding, neither the Staff nor UPPCo used projected revenues; thus, in UPPCo's next SRM review case, the company shall present applicable forecasted offset amounts as required under Section 6w(3)(b). To calculate the applicable forecasted offset amounts, the Commission finds that the method approved in Consumers' and DTE Electric's SRM cases is reasonable, appropriate, and consistent with Section 6w. *See, e.g.*, November 21, 2017 orders in Case No. U-18239, pp. 65-68 and Case No. U-18248, pp. 66-69.

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[6] UPPCo's objection to the Staff's reference to the NARUC Manual in the Staff's initial brief, (without having entered the manual as an exhibit), is not well-taken. The Commission notes that Dr. Olive's testimony also contained references to Chapter 4 of the NARUC Manual, to which UPPCo did not raise an objection. The Staff's testimony on its calculation of total capacity cost was sufficient for the purposes of the Commission's determination here, without any need to rely on the NARUC Manual.

3. Rate Design and Reconciliation

The Commission agrees with the Staff that the results of the allocation of capacity-related costs in the COSS should be used to set a separate charge for each customer class. The Commission also finds that the Staff's rate design proposal is reasonable and should be adopted.

The Commission agrees with the Staff's explanation that the best proxy for contribution to capacity-related cost incurrence is through annual kWh charges for rate schedules without demand charges, on-peak kWh charges for schedules without demand charges that can be charged on-peak, and on-peak kW charges for rate schedules with demand charges. Thus, the Commission adopts the Staff's recommendation to collect the SRM charge based on annual kWh for non-demand billed customers for whom the company lacks the ability to charge based on on-peak kWh. For those non-demand billed customers who can be billed on-peak, on-peak kWh SRM charges are approved, and for demand-billed customers, the Commission approves demand charges. With respect to UPPCo's proposed modification to its original recommendation, which would allow choice customers rather than the AES to be charged, the Commission finds that UPPCo's proposal lacks sufficient detail to be properly implemented and, as described in UPPCo's testimony the method does not appear to comport with the other determinations made in this order.

Section 6w(3) provides that no new capacity charge may be required to be paid before June 1, 2018. The Commission finds that the capacity charge approved by this order shall apply to bundled customers as of that date. Exhibit A (which is not physically attached to the order) contains the revised tariff sheets reflecting the application of the decisions made herein to the Staff's proposed rate design, and Exhibit B, attached to this order, shows the computation method for arriving at the capacity charge.

Section 6w(4) provides for a true-up of "the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge." Projected net revenues are addressed in Section 6w(3)(b). Thus, the Commission agrees with the parties that the reconciliation required under Section 6w(4) is limited to the amounts forecasted under Section 6w(3)(b), and should occur in the annual PSCR reconciliation – a currently-existing proceeding that is designed for this precise type of true-up and which already calls for the filing of much of the relevant information in that docket, since PPA expenses are reconciled in PSCR cases . The Commission does not find, at this time, that the creation of a standalone proceeding is necessary.

4. Application of the Capacity Charge to Choice Customers

UPPCo, MECA, and CNE argue that the capacity charge should be levied on the AES and not on choice customers. The Commission finds that a capacity charge shall be levied on the ROA customer receiving the capacity service from the incumbent utility for several reasons. As these intervenors are well aware, Section 201(b)(1) of the FPA, 16 USC 824(b)(1), vests the FERC with jurisdiction over wholesale sales of electric energy in interstate commerce; and Section 205(a) of the FPA, 16 USC 824d(a), confers on the FERC the responsibility to ensure that wholesale power sales rates and charges are just and reasonable. *See, Mississippi Power & Light Co v Mississippi ex rel Moore*, 487 US 354, 371; 108 SCt 2428; 101 LEd2d 322 (1988). AESs resell their product to choice customers. Thus, were the Commission to, pursuant to Section 6w, set a capacity charge to be paid by AESs to incumbent utilities, Section 6w would be a legal nullity subject to immediate federal preemption. The Commission finds it disingenuous to posit that the Legislature mistakenly engaged in the pointless enactment of a statute requiring the Commission to set a wholesale rate for AESs, when other aspects of Section 6w reveal that the Legislature well understood the role that the FERC plays in the MISO process.

Rules of statutory construction provide that the "words used in the statute are the most reliable indicator of the Legislature's intent and should be interpreted on the basis of their ordinary meaning and the context within which they are used." *Dep't of Environmental Quality v Worth Twp,* 491 Mich 227, 237-238; 814 NW2d 646 (2012). Effect should be given to every phrase, clause, and word in the statute "read and understood in its grammatical context," and the statute "must be read as a whole unless something different was clearly intended." *Id.* The Commission "must give effect to every word, phrase, and clause in a statute and avoid an interpretation that would render any part of the statute surplusage or nugatory." *Johnson v Recca*, 492 Mich 169, 177; 821 NW2d 520 (2012). Clearly, this concept extends to an entire statute. The Commission has no jurisdiction over wholesale power sales – a fact that the Commission feels justified in believing the Legislature to be aware of.

As the rules of statutory construction make clear, the words used in the statute are the most reliable indicator of the intended meaning. The specific language of Section 6w is instructive. Everywhere that the charge is referred to, the Commission is instructed to apply it to full-service or AES "load." Section 6w(3) provides "the charge must be applied to alternative electric load," and the Commission "shall ensure that the resulting capacity charge does not differ for full service load and alternative electric load." Section 6w(6) provides that the charge "must be paid for the portion of [the utility's] load taking service from the AES not covered by capacity." Section 6w(7) provides that the incumbent utility "shall provide capacity to meet the capacity obligation for the portion of that load taking service from an AES." And, Section 6w(8)(b)(i) provides that the Commission shall "[f]or alternative electric load, require the payment of a capacity charge that is determined, assessed, and applied in the same manner as under subsection (3) for that portion of the load not covered as set forth" in subsections (6) and (7).

"Load" can be ambiguous, but it is generally understood to mean power consumed, as by a device or circuit.[7] "To different people in different departments of a utility, load may mean different things; such as active power (in kW), apparent power (in kVA), energy (in kWh), current (in ampere), voltage (in volt), and even resistance (in ohm). In load forecasting, load usually refers to demand (in kW) or energy (in kWh)."[8] What each of these definitions has in common is that they relate to the use of power by the end-user. In addition to Section 6w, "load" is frequently referred to in the choice law, 2001 PA 141 (Act 141), MCL 460.10 *et seq*., as well. For example, Section 10a(1)(b) of Act 141 requires the Commission to "allocate the amount of load that will be allowed to be served by alternative electric suppliers;" and Section 10bb(3) provides that "'aggregation' means the combining of electric loads of multiple retail customers or a single customer with multiple sites." It is important to remember that the capacity charge is paid by both full service and choice customers. Each use of "load" in both the choice law and in Section 6w refers to power that is consumed by end-users and could often be replaced with the word "customers;" but none of these references to "load" make sense when replaced with "alternative electric supplier." Nothing may be read into a statute that is not "within the manifest intent of the Legislature as derived from the words of the statute itself." *Covenant Medical Ctr v State Farm Mut Automobile Ins Co*, 500 Mich 191, ___; 895 NW2d 490, 495 (2017) (citation omitted). The Commission finds that to levy the capacity charge on an AES would require reading into Section 6w something that is not there.

[7] Merriam-Webster Third New International Dictionary (1st ed.).

[8] Hong, T., *et al*, Load Forecasting Case Study, January 15, 2015, NARUC and Eastern Interconnection States' Planning Council, p. 9-2.

In making their arguments, UPPCo, CNE, and MECA emphasize the wording of Section 6w(6), which requires an "electric provider" that has previously made a satisfactory demonstration to give notice to the Commission if it expects to be unable to make its demonstration in the next (four-year-out) planning year "and instead expects to pay a capacity charge." The Commission finds that this sentence must be read in the context of Section 6w as a whole. *Johnson,* 492 Mich at 177. There is no entity that could give such notice other than the AES, since only the AES knows whether it intends to provide its customers with sufficient capacity or intends to provide something less. ROA customers are incapable of providing such notice, even though they are the parties that will be paying the charge.

The Legislature has chosen to make incumbent utilities (which are subject to rate regulation) the capacity suppliers of last resort under Section 6w(7). The capacity charge is a retail rate, designed to recover the incumbent utility's cost of providing capacity service, to whatever type of customer load – bundled or choice. The Commission has full discretionary authority to set just and reasonable rates, which are based on a determination of the reasonable costs of doing business and what charges and expenses to allow as costs of operation. MCL 460.6; *Detroit Edison Co v Public Service Comm,* 127 Mich App 499, 524; 342 NW2d 273 (1983). The service is provided by the utility, and thus must be billed by the utility. And this service to provide long-term resource adequacy as a default provider is essential to ensuring reliable electric service for all customers. *See,* MCL 460.10(a), (c). MECA, UPPCo and CNE correctly note that AESs remain free to contract with their customers in whatever way they wish to mitigate the effect of the capacity charge, when capacity must be supplied by the incumbent utility because the AES has failed to make a satisfactory demonstration. And the Staff correctly points out that if the service were billed to the AES, there would be no way for the Commission to carry out the mandate that the capacity charge paid by bundled load and choice load must not differ, nor any way for the Commission to ensure that the cost to the customer reflects the cost to serve that customer under MCL 460.11.

Finally, the Commission wishes to elaborate on how Section 6w and the choice law are intended to work together. In the two decades since varying forms of retail competition were implemented in states across the country, different models for continued state oversight over the supply and delivery of electricity have emerged. Provision of electricity to end use customers is comprised of multiple components, including power supply service (e.g., energy and capacity), wires service (e.g., distribution), and other functions associated with the use of electricity, such as energy efficiency programs, providing bill payment assistance to low-income customers, and collection of funds to use for decommissioning of nuclear generating facilities. Even with the advent of retail competition, many states continued to set prices for "default" electricity service to ensure the availability of reliable power to end-users and meet other goals including, in some cases, state policy objectives. Under Act 141, Michigan left this default service responsibility with the incumbent utility, and the Commission retained jurisdiction to regulate the utility's rates for electric generation services. The regulated utility was expected to compete with the licensed AESs in the provision of power supply service while at the same time providing wires service, as well as other functions to all end-use customers. In other states with restructured electricity markets, default power supply services were provided by either the incumbent utility or another entity selected through a competitive bidding process or other mechanism. Some states that required the incumbent utility to fully divest its generation as a competitive function still facilitated and approved procurement activities for energy or capacity to reliably serve some or all end-use customers under their retail choice model (or the transition thereto).

The purchase of energy, capacity, or both from a third party by the LSE, whether it is a vertically integrated utility under state rate regulation or a competitive retailer or default service provider under a retail choice construct, is a wholesale purchase. But charging customers for the provision of electricity supply and other services associated with customers' electricity use is decidedly a retail activity. States have defined what types of entities provide these services with varying degrees of specificity. In some states, it is only the regulated incumbent utility providing power supply, wires service, and other functions, costs for all of which are recovered through retail rates. In states with retail competition, some of these services, such as power supply, are provided by a third party under market-based prices, or as part of regulated default service, with the wires and other functions associated with electricity use collected through nonbypassable charges flowing through to the customer (either directly or in combination with the energy supply portion).

The provision of power supply service includes both capacity and energy components, among others. Providing long-term "capacity service" to customers to ensure future resource adequacy and provide reasonable assurance that energy will be actually available at any given moment (particularly peak periods) is related to, but notably distinct from, supplying only "energy." These two products or services – energy and capacity – are distinguished from one another in many wholesale contractual arrangements, such as PPAs and in long-term resource planning. They are measured differently as well – kW versus kWh. The costs to provide capacity and energy are allocated to, and collected from, end-use customers differently through conventional cost allocation and rate design methodologies. And like other services, such as energy efficiency, costs for which are recovered through nonbypassable retail charges assessed to end use customers, the capacity charge under Section 6w is set by the state as a retail charge assessed to retail customers.

This is an acknowledgment that Section 6w creates a new category of default service, namely, the provision of capacity service to choice customers whose energy providers do not secure long-term capacity. The capacity charge established under Section 6w is intended to compensate the default supplier (i.e., the incumbent utility) for providing long-term capacity to customers, including customers of energy providers who supply energy but not long-term capacity. This is just one of many services associated with retail electric service that flows through to end-use customers as a retail charge.

The Commission notes that under Section 6w, the same charge applies to "load" whether it is bundled (receiving all services from the incumbent utility) or unbundled (receiving energy service from an AES that has chosen not to provide long-term capacity). And like many states that designated either the incumbent utility or another entity to provide certain default services, Michigan is certainly within its rights to declare that the rate-regulated incumbent utility, certificated by the Commission to serve a specific service area, shall provide this critical long-term reliability service to designated customers. Of course, with this statutorily-mandated assignment of responsibility for the planning and provision of long-term capacity supplies comes the ability for the affected provider to charge applicable end-use customers taking this particular service from the utility. Supplying long-term capacity is as fundamental to ensuring electric reliability as maintaining the distribution system or other critical functions of the utility for which it is compensated by customers using the service.

THEREFORE, IT IS ORDERED that:

A. If a state reliability mechanism capacity charge is levied on retail open access customers at the conclusion of a show cause proceeding for planning year 2018 it shall be for the first four consecutive planning years, and any charge levied at the conclusion of a show cause proceeding shall be levied and applicable for a single year.

B. Beginning June 1, 2018, Upper Peninsula Power Company shall implement a state reliability mechanism capacity charge of $90,810 per megawatt-year, or $249 per megawatt-day, for full-service customers, using the Commission Staff's rate design, as illustrated in Attachments A and B attached to this order. Thirty days prior to June 1, 2018, Upper Peninsula Power Company shall file tariff sheets substantially similar to those contained in Attachment A, employing the capacity charge calculation in Attachment B. Due to the size of Attachment A, it is not physically attached to the original order contained in the official docket or paper copies of this order, but is electronically appended to this order, which is available on the Commission's website.

C. In Upper Peninsula Power Company's annual power supply cost recovery reconciliation proceeding, the amounts forecasted pursuant to MCL 460.6w(3)(b) shall be reconciled against actual amounts, consistent with the requirements of MCL 460.6w(4), as a separate reconciliation.

D. If an alternative electric supplier operating in Upper Peninsula Power Company's service territory fails to make a satisfactory demonstration regarding its forward capacity obligations pursuant to MCL 460.6w(8), the resulting state reliability mechanism capacity charge shall be levied by Upper Peninsula Power Company on the retail open access customers of that alternative electric supplier on a pro rata basis.

E. Upper Peninsula Power Company is directed to file a standalone contested case for the annual review of its state reliability mechanism capacity charge by April 1, 2018, and annually thereafter, unless the utility expects that the annual review will be taking place in a rate case or power supply cost recovery case that will conclude by December 1 of each year. If Upper

Peninsula Power Company does not file a standalone contested case by April 1, 2018, it shall notify the Commission in this docket of the expected approval path and timing for the annual review of the state reliability mechanism capacity charge.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Rachael A. Eubanks, Commissioner

By its action of November 30, 2017.

Kavita Kale, Executive Secretary

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

6th Rev. Sheet No. D-4.00
Replaces 5th Rev. Sheet No. D-4.00

D2. Residential Service **A-1**

WHO MAY TAKE SERVICE:

Any residential customer in a single family dwelling or a duplex using service for domestic purposes. This rate is also available to certain multiple dwellings in accordance with the standard rules. Services to garages and outbuildings not used for commercial purposes will also be classified as residential. Farm customers using electric service for the production of agricultural products for commercial purposes will be placed on the appropriate commercial rate. Optional Power Supply Service is available only to Customers not taking power supply service under rate schedule RAST, or not required to receive service under rate schedule PSDS.

TERRITORY APPLICABLE:

All territory served in the Company's Integrated System.

CHARACTER OF SERVICE:

Single-phase, alternating current, 60 hertz, nominally at 120/240 volts.

RATE: DISTRIBUTION SERVICE

Service Charge:
$15.00/Mo. for Year-Round
$0.4932/Day for Year-Round
$30.00/Mo. for Seasonal
$0.9863/Day for Seasonal

Energy Charge:
$0.10904 per kWh for all kWh

POWER SUPPLY SERVICE (Optional)

Energy Charge:

	Capacity	Non-Capacity	Total
R			
R	$0.02461	$0.07562	$0.10023 per kWh for all kWh

MINIMUM CHARGE:

The service charge included in the rate.

POWER SUPPLY COST RECOVERY CLAUSE:

This rate is subject to the Company's Power Supply Cost Recovery shown on Sheet No. D-3.00.

ENERGY OPTIMIZATION SURCHARGE:

This rate is subject to the Energy Optimization Surcharge shown on Sheet No. D-73.00.

Continued on Sheet No. D-5.00

D2. Residential Service **A-2**

WHO MAY TAKE SERVICE:

Any residential customer in a single family dwelling or a duplex using service for domestic purposes. This rate is also available to certain multiple dwellings in accordance with the standard rules. Services to garages and outbuildings not used for commercial purposes will also be classified as residential. Farm customers using electric service for the production of agricultural products for commercial purposes will be placed on the appropriate commercial rate. Optional Power Supply Service is available only to Customers not taking power supply service under rate schedule RAST, or not required to receive service under rate schedule PSDS.

TERRITORY APPLICABLE:

All territory served in the Company's Iron River District.

CHARACTER OF SERVICE:

Single-phase, alternating current, 60 hertz, nominally at 120/240 volts.

RATE: DISTRIBUTION SERVICE

Service Charge:
$15.00/Mo. for Year-Round
$0.4932/Day for Year-Round
$30.00/Mo. for Seasonal
$0.9863/Day for Seasonal

Energy Charge:
$0.10305 per kWh for all kWh

POWER SUPPLY SERVICE (Optional)

Energy Charge:

R	Capacity	Non-Capacity	Total
R	$0.02463	$0.07261	$0.09724 per kWh for all kWh

MINIMUM CHARGE:

The service charge included in the rate.

POWER SUPPLY COST RECOVERY CLAUSE:

This rate is subject to the Company's Power Supply Cost Recovery shown on Sheet No. D-3.00.

ENERGY OPTIMIZATION SURCHARGE:

This rate is subject to the Energy Optimization Surcharge shown on Sheet No. D-73.00.

Continued on Sheet D-7.00

D2. Residential Heating Service **AH-1**

WHO MAY TAKE SERVICE:
Any residential customer in a single family dwelling or a duplex using service for domestic purposes, provided the major electric space heating facilities are permanently installed and are the primary source of space heating. This rate is also available to certain multiple dwellings in accordance with the standard rules. Services to garages and outbuildings not used for commercial purposes will also be classified as residential. Farm customers using electric service for the production of agricultural products for commercial purposes will be placed on the appropriate commercial rate. Optional Power Supply Service is available only to Customers not taking power supply service under rate schedule RAST, or not required to receive service under rate schedule PSDS.

CHARACTER OF SERVICE:
Single-phase, alternating current, 60 hertz, nominally at 120/240 volts.

RATE: DISTRIBUTION SERVICE
Service Charge:
$15.00 per month
$0.4932 per day

Energy Charge:
For billing months of June through September
$0.10904 per kWh for all kWh
For billing months of October through May
$0.11995 per kWh for the first 500 kWh
$0.04076 per kWh for the excess

POWER SUPPLY SERVICE (Optional)
Energy Charge:
For billing months of June through September

R	Capacity	Non-Capacity	Total
R	$0.02456	$0.07200	$0.09656 per kWh for all kWh

For billing months of October through May

R	Capacity	Non-Capacity	Total
R	$0.02456	$0.05845	$0.08301 per kWh for the first 500 kWh
R	$0.02456	$0.10134	$0.12590 per kWh for the excess

POWER SUPPLY COST RECOVERY CLAUSE:
This rate is subject to the Company's Power Supply Cost Recovery shown on Sheet No. D-3.00.

ENERGY OPTIMIZATION SURCHARGE:
This rate is subject to the Energy Optimization Surcharge shown on Sheet No. D-73.00.

MINIMUM CHARGE:
The service charge included in the rate.

Continued on Sheet D-9.00

D2. General Service **C-1**

WHO MAY TAKE SERVICE:
Any customer for commercial or industrial purpose with a billing demand of less than 25 kW. Optional Power Supply Service is available only to Customers not taking power supply service under rate schedule RAST, or not required to receive service under rate schedule PSDS.

CHARACTER OF SERVICE:
Single or three-phase, alternating current, 60 hertz at standard available voltages.

RATE: DISTRIBUTION SERVICE:
Service Charge:
$17.00 per month
$0.5589 per day

Energy Charge:
$0.05760 per kWh for all kWh

POWER SUPPLY SERVICE (Optional)
Energy Charge

R	Capacity	Non-Capacity	Total
R	$0.02181	$0.08924	$0.11105 per kWh for all kWh

MINIMUM CHARGE:
The service charge included in the rate, plus the energy optimization surcharge.

POWER SUPPLY COST RECOVERY CLAUSE:
This rate is subject to the Company's Power Supply Cost Recovery shown on Sheet No. D-3.00.

ENERGY OPTIMIZATION SURCHARGE:
This rate is subject to the Energy Optimization Surcharge shown on Sheet No. D-73.00.

TERMS OF PAYMENT:
Bills are due in 21 days from date of bill. A delayed payment charge of 2% may be applied to the unpaid balance if the bill is not paid in full on or before the due date thereon.

RULES APPLYING:
(1) Service is governed by the Company's Standard Rules and Regulations.
(2) Conjunctional billing will not be permitted in cases where the customer is presently being served lighting and power loads through separate meters. In these instances, whenever the customer at his expense will arrange his wiring to receive energy through one single metered service, then this rate shall apply to his entire requirements.

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

6th Rev. Sheet No. D-14.00
Replaces 5th Rev. Sheet No. D-14.00

D2. Commercial Heating Service **H-1**

WHO MAY TAKE SERVICE:
Any customer for commercial purposes provided that their electric space heating facilities are permanently installed and are the primary source of space heating. Optional Power Supply Service is available only to Customers not taking power supply service under rate schedule RAST, or not required to receive service under rate schedule PSDS.

CHARACTER OF SERVICE:
Single or three-phase, alternating current, 60 hertz, nominally at 120/240 volts.

RATE: DISTRIBUTION SERVICE
Service Charge:
$17.00 per month
$0.5589 per day

Energy Charge:
For billing months of June through September
$0.05760 per kWh for all kWh
For billing months of October through May
$0.06336 per kWh for first 1000 kWh
$0.02273 per kWh for the excess

POWER SUPPLY SERVICE (Optional)
Energy Charge:
For billing months of June through September

	Capacity	Non-Capacity	Total
R	Capacity	Non-Capacity	Total
R	$0.02155	$0.09050	$0.11205 per kWh for all kWh

For billing months of October through May

	Capacity	Non-Capacity	Total
R	Capacity	Non-Capacity	Total
R	$0.02155	$0.08146	$0.10301 per kWh for first 1000 kWh
R	$0.02155	$0.08073	$0.10228 per kWh for the excess

MINIMUM CHARGE:
The service charge included in the rate, plus the energy optimization charge.

POWER SUPPLY COST RECOVERY CLAUSE:
This rate is subject to the Company's Power Supply Cost Recovery shown on Sheet No. D-3.00.

ENERGY OPTIMIZATION SURCHARGE:
This rate is subject to the Energy Optimization Surcharge shown on Sheet No. D-73.00.

TERMS OF PAYMENT:
Bills are due in 21 days from date of bill. A delayed payment charge of 2% may be applied to the unpaid balance if the bill is not paid in full on or before the due date thereon.

RULES APPLYING:
1) Service is governed by the Company's Standard Rules and Regulations.
2) Permanently installed heating equipment is heating equipment that is hard-wired into an electric panel which may or may not have a plug.

D2. Light and Power Service **P-1**

WHO MAY TAKE SERVICE:
Any customer for light and power purposes with a billing demand equal to or greater than 25 kW but less than 200 kW. To qualify, the customer must maintain a demand equal to or greater than 25 kW for three consecutive months and at least once in each succeeding twelve-month period. Optional Power Supply Service is available only to Customers not taking power supply service under rate schedule RAST, or not required to receive service under rate schedule PSDS.

CHARACTER OF SERVICE:
Single or three-phase, alternating current, 60 hertz at standard available voltages.

RATE: DISTRIBUTION SERVICE

Service Charge:
$35.00 per month
$1.1507 per day

Demand Charge:
$4.00 per kW per month

Energy Charge:
$0.01801 per kWh for all kWh

POWER SUPPLY SERVICE (Optional)

Demand Charge:

R	Capacity	Non-Capacity	Total
R	$7.32	$1.87	$9.19 per kW per month

Energy Charge:
$0.08475 per kWh for all kWh

MINIMUM CHARGE:
The capacity charge for 25 kW or the contract minimum, whichever is greater, plus the energy optimization charge.

POWER SUPPLY COST RECOVERY CLAUSE:
This rate is subject to the Company's Power Supply Cost Recovery shown on Sheet No. D-3.00.

ENERGY OPTIMIZATION SURCHARGE:
This rate is subject to the Energy Optimization Surcharge shown on Sheet No. D-73.00.

POWER FACTOR BILLING ADJUSTMENT:
This rate is subject to the Company's Power Factor Billing Adjustment.

Continued on Sheet No. D-17.00

D2. Large Commercial & Industrial Service **Cp-U**

Continued from Sheet No. D-25.10

POWER SUPPLY SERVICE (Optional)

		Secondary	Primary	Transmission
	On-Peak			
	Firm Demand: $/kW			
R	Capacity	$6.11	$5.89	$5.68
R	Non-Capacity	$4.94	$4.77	$4.58
R	Total	$11.05	$10.66	$10.26
	Interruptible Demand: $/kW			
R	Capacity	$1.96	$1.75	$1.52
R	Non-Capacity	$1.59	$1.41	$1.24
R	Total	$3.55	$3.16	$2.76

7:00 AM to 11:00 PM; Monday through Friday (except holidays).

Energy Charge

1. On-Peak

	Secondary	Primary	Transmission
Energy Charge:$/kWh	$0.09003	$0.08678	$0.08360

7:00 AM to 11:00 PM; Monday through Friday (except holidays).

2. Off-Peak

	Secondary	Primary	Transmission
Energy Charge:$/kWh	$0.05854	$0.05642	$0.05435

11:00 PM to 7:00 AM; Monday through Friday, all day Saturday, Sunday, and holidays.

MINIMUM CHARGE

The monthly minimum charge is the customer charge, demand charges, substation charges and the energy optimization charge.

POWER SUPPLY COST RECOVERY CLAUSE

This rate is subject to the Company's Power Supply Cost Recovery shown on Sheet No. D-3.00.

PRIMARY & TRANSMISSION CHARGES

The customer shall provide a support for the company to terminate the primary conductors and install other required equipment. Customer owned substation equipment shall be operated and maintained by the customer. The support and substation equipment is subject to the company's inspection and approval.

ENERGY OPTIMIZATION

This rate is subject to the Energy Optimization Surcharge shown on Sheet No. D-73.00.

DEFINITIONS

For customers with company metering equipment installed at:

Secondary	Under 6,000 volts
Primary	6,000 volts to 15,000 volts, inclusive
Transmission	Over 15,000 volts

Continued to Sheet No. D-25.30

D2. Street Lighting Service **SL-3**

WHO MAY TAKE SERVICE:
Any municipality for customer owned, operated and maintained street lighting and/or traffic signal system.

CHARACTER OF SERVICE:
Single-phase, alternating current, 60 hertz, nominally at 120/240 volts.

RATE:

Service Charge:
$17.00 per month
$0.5589 per day

Energy Charge

R	Capacity	Non-Capacity	Total
R	$0.01872	$0.14852	$0.16724 per kWh

MINIMUM CHARGE:
The service charge included in the rate, plus the energy optimization charge.

POWER SUPPLY COST RECOVERY CLAUSE:
This rate is subject to the Company's Power Supply Cost Recovery shown on Sheet No. D-3.00.

ENERGY OPTIMIZATION SURCHARGE:
This rate is subject to the Energy Optimization Surcharge shown on Sheet No. D-73.00.

TERMS OF PAYMENT:
Bills are due in 21 days from date of bill. A delayed payment charge of 2% may be applied to the unpaid balance if the bill is not paid in full on or before the due date thereon.

CONTRACT:
Minimum period of three years subject to automatic renewal periods of one year each. The contract may be terminated at the end of any yearly period upon 90 days written notice by either party. If the contract is terminated before the three year period, the customer may be responsible for the lesser of the cost of removal or the remaining monthly charges.

RULES APPLYING:
Service is governed by the Company's Standard Rules and Regulations.

D2. Street Lighting Service (Closed) **SL-5**

WHO MAY TAKE SERVICE:
Any municipality owning its own street lighting system including poles, fixtures, wires, transformers, time switches and other accessories. Additions to mercury vapor lighting services are closed to new customers. This option is closed to new customers effective January 1, 2014.

HOURS OF SERVICE:
All night - Dusk to Dawn

CHARACTER OF SERVICE:
Single-phase, alternating current, 60 hertz at the Company's distribution voltage.

RATE:
Light Emitting Diode (LED)

R Non-Capacity

	Watts	Per Lamp Per Month All Night
R	0-99	$10.75
R	100-199	$14.14
R	200-299	$17.52
R	300-399	$20.90

Sodium Vapor

R Non-Capacity

	Lumens	Watts	Per Lamp Per Month All Night
R	9,000	100	$11.96
R	14,000	150	$14.16
R	27,000	250	$18.38
R	45,000	400	$23.33

Mercury Vapor

R Non-Capacity

Lumens	Watts	All Night
20,000	400	$27.66

R

R Capacity Energy: All Lights
$0.01872 per kWh

Type of Facility	Monthly Charge
Additional Wood Pole	$4.51/pole
Span of Conductor (200 feet)	$3.26/span

Continued on Sheet No. D-52.00

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

6th Rev. Sheet No. D-53.00
Replaces 5th Rev. Sheet No. D-53.00

D2. Street Lighting Service **SL-6**

WHO MAY TAKE SERVICE:
Any municipality from Company owned, operated and maintained street lighting system as available. Additions to mercury vapor lighting services are closed to new customers.

HOURS OF SERVICE: All night – Dusk to Dawn

CHARACTER OF SERVICE:
Single-phase, alternating current, 60 hertz at the Company's distribution voltage.

RATE:

Sodium Vapor — Per Lamp Per Month

R Non-Capacity

	Lumens	Watts	All Night
R	5,670	70	$18.00 (Closed)
R	9,000	100	$18.70
R	14,000	150	$22.70
R	27,000	250	$25.77
R	45,000	400	$36.28

Mercury Vapor

R Non-Capacity

	Lumens	Watts	All Night
R	7,500	175	$19.04
R	20,000	400	$34.96

Metal Halide

R Non-Capacity

	Lumens	Watts	All Night
R	8,800	175	$31.06
R	36,000	400	$38.24
R	110,000	1,000	$70.46

LED

R Non-Capacity

Lumens	Watts	All Night
9,000*	100*	$17.17
14,000*	150*	$20.37
27,000*	250*	$23.97

R Capacity Energy: All Lights
R $0.01872 per kWh

SPECIAL TERMS AND CONDITIONS
The above charges are for lighting units on existing company-owned distribution facilities. The company will own and install the luminaires, complete with lamp, control device, and six-foot mast arm, mounted on an existing company pole. If the customer requests the following facilties, the monthly charges listed below shall be added to the above charges.

Type of Facility	Monthly Charge
Additional Wood Pole	$4.51/pole
Span of Conductor (200 feet)	$3.26/span

* The wattages and lumens listed under the LED lamps are wattages and lumens of sodium vapor lamps to which the LED lamps are considered equivalent. Actual wattages and lumens of LED lamps may vary.

Continued on Sheet No. D-54.00

D2. Dusk To Dawn Outdoor Security Lighting **Z-3**

WHO MAY TAKE SERVICE:
Any customer for dusk to dawn outdoor security lighting where customer takes service at the same premises under a standard rate schedule. Additions to mercury vapor lighting services are closed to new customers.

TERRITORY APPLICABLE
All territory served in the Company's Integrated System.

HOURS OF SERVICE:
Daily from dusk to dawn.

CHARACTER OF SERVICE:
Single-phase, alternating current, 60 hertz, nominally at 120 volts.

RATE: Sodium Vapor

R Non-Capacity

	Lumens	Watts	Monthly Charge
R	9,000	100	$20.74/Lamp
R	27,000	250	$31.78/Lamp
R	45,000	400	$38.47/Lamp

Mercury Vapor

R Non-Capacity

	Lumens	Watts	Monthly Charge
R	7,500	175	$18.40/Lamp
R	20,000	400	$34.36/Lamp

Metal Halide

R Non-Capacity

	Lumens	Watts	Monthly Charge
R	36,000	400	$38.21/Lamp
R	110,000	1,000	$70.34/Lamp

Capacity Energy: All Lights
$0.01882 per kWh

SPECIAL TERMS AND CONDITIONS

The above charges are for lighting on existing company-owned distribution facilities. The Company will own and install the luminaire, complete with lamp, control device and up to and including a 6-foot mast arm, mounted on an existing company pole. If the customer requests a mast arm in excess of 6 feet it will be considered special facilities. If the customer requests an additional pole and span, the monthly charges listed below shall be added to the above charges.

Type of Facility	Monthly Charge
Additional Wood Pole	$4.51/pole
Span of Conductor (200 feet)	$3.26/span

Continued on Sheet No. D-58.00

D2. Dusk To Dawn Outdoor Security Lighting **Z-4**

WHO MAY TAKE SERVICE:
Any customer for dusk to dawn outdoor security lighting where customer takes service at the same premises under a standard rate schedule. Additions to mercury vapor lighting services are closed to new customers.

TERRITORY APPLICABLE:
All territory served in the Company's Iron River District.

HOURS OF SERVICE:
Daily from dusk to dawn.

CHARACTER OF SERVICE:
Single-phase, alternating current, 60 hertz, nominally at l20 volts.

RATE: Sodium Vapor

R Non-Capacity

	Lumens	Watts	Monthly Charge
R	9,000	100	$16.16/Lamp
R	27,000	250	$29.13/Lamp
R	45,000	400	$30.62/Lamp

Mercury Vapor

R Non-Capacity

	Lumens	Watts	Monthly Charge
R	7,500	175	$16.68/Lamp

Metal Halide

R Non-Capacity

	Lumens	Watts	Monthly Charge
R	36,000	400	$30.47/Lamp
R	110,000	1,000	$51.88/Lamp

R Capacity Energy: All Lights
R $0.01847 per kWh

SPECIAL TERMS AND CONDITIONS

The above charges are for lighting on existing company-owned distribution facilities. The Company will own and install the luminaire, complete with lamp, control device and up to and including a 6-foot mast arm, mounted on an existing company pole. If the customer requests a mast arm in excess of 6 feet it will be considered special facilities. If the customer requests an additional pole and span, the monthly charges listed below shall be added to the above charges.

Type of Facility	Monthly Charge
Additional Wood Pole	$4.51/pole
Span of Conductor (200 feet)	$3.26/span

Continued on Sheet D-60.00

Capacity Revenue Requirement	$	11,896,077	
2016 System Peak		131	MW
Capacity Charge	$	90,810	MW/Year
	$	249	MW/Day

PROOF OF SERVICE

STATE OF MICHIGAN)

Case No. U-18254

County of Ingham)

Lisa Felice being duly sworn, deposes and says that on November 30, 2017 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Lisa Felice

Lisa Felice

Subscribed and sworn to before me
this 30th day of November 2017

Steven J. Cook

Steven J. Cook
Notary Public, Ingham County, Michigan
As acting in Eaton County
My Commission Expires: April 30, 2018

Service List for U-18254

Name	Email Address
Meredith Beidler	beidlerm@michigan.gov
Laura Chappelle	lachappelle@varnumlaw.com
Lauren Donofrio	donofriol@michigan.gov
Jason Hanselman	jhanselman@dykema.com
Jennifer Heston	jheston@fraserlawfirm.com
Timothy Lundgren	tjlundgren@varnumlaw.com
Toni Newell	tlnewell@varnumlaw.com
Suzanne Sonneborn	sonneborns@michigan.gov
Monica Stephens	stephensm11@michigan.gov
Upper Peninsula Power Company	ghaehnel@uppco.com
Sherri Wellman	wellmans@millercanfield.com

GEMOTION DISTRIBUTION SERVICE LIST

kadarkwa@itctransco.com	ITC
tjlundgren@varnumlaw.com	Energy Michigan
lachappelle@varnumlaw.com	Energy Michigan
CBaird-Forristall@MIDAMERICAN.COM	Mid American
david.d.donovan@XCELENERGY.COM	Xcel Energy
ddasho@cloverland.com	Cloverland
bmalaski@cloverland.com	Cloverland
vobmgr@UP.NET	Village of Baraga
braukerL@MICHIGAN.GOV	Linda Brauker
info@VILLAGEOFCLINTON.ORG	Village of Clinton
jgraham@HOMEWORKS.ORG	Tri-County Electric Co-Op
mkappler@HOMEWORKS.ORG	Tri-County Electric Co-Op
psimmer@HOMEWORKS.ORG	Tri-County Electric Co-Op
aurora@FREEWAY.NET	Aurora Gas Company
frucheyb@DTEENERGY.COM	Citizens Gas Fuel Company
mpscfilings@CMSENERGY.COM	Consumers Energy Company
jim.vansickle@SEMCOENERGY.COM	SEMCO Energy Gas Company
kay8643990@YAHOO.COM	Superior Energy Company
ebrushford@UPPCO.COM	Upper Peninsula Power Company
christine.kane@we-energies.com	WEC Energy Group
ghaehnel@uppco.com	Upper Peninsula Power Company
kerriw@TEAMMIDWEST.COM	Midwest Energy Coop
dave.allen@TEAMMIDWEST.COM	Midwest Energy Coop
meghant@TEAMMIDWEST.COM	Midwest Energy Coop
tharrell@ALGERDELTA.COM	Alger Delta Cooperative
tonya@CECELEC.COM	Cherryland Electric Cooperative
bscott@GLENERGY.COM	Great Lakes Energy Cooperative
sculver@glenergy.com	Great Lakes Energy Cooperative
panzell@glenergy.com	Great Lake Energy Cooperative
dmartos@LIBERTYPOWERCORP.COM	Liberty Power Delaware (Holdings)
kmarklein@STEPHENSON-MI.COM	Stephson Utilities Department
debbie@ONTOREA.COM	Ontonagon County Rural Elec
sharonkr@PIEG.COM	Presque Isle Electric & Gas Cooperative, INC
dbraun@TECMI.COOP	Thumb Electric
rbishop@BISHOPENERGY.COM	Bishop Energy
mkuchera@AEPENERGY.COM	AEP Energy
todd.mortimer@CMSENERGY.COM	CMS Energy
jkeegan@justenergy.com	Just Energy Solutions
david.fein@CONSTELLATION.COM	Constellation Energy
kate.stanley@CONSTELLATION.COM	Constellation Energy
kate.fleche@CONSTELLATION.COM	Constellation New Energy
mpscfilings@DTEENERGY.COM	DTE Energy
bgorman@FIRSTENERGYCORP.COM	First Energy
vnguyen@MIDAMERICAN.COM	MidAmerican Energy

Updated 8-18-2017

GEMOTION DISTRIBUTION SERVICE LIST

rarchiba@FOSTEROIL.COM	My Choice Energy
greg.bass@calpinesolutions.com	Calpine Energy Solutions
rabaey@SES4ENERGY.COM	Santana Energy
cborr@WPSCI.COM	Spartan Renewable Energy, Inc. (Wolverine Power Marketing Corp)
john.r.ness@XCELENERGY.COM	Xcel Energy
cityelectric@ESCANABA.ORG	City of Escanaba
crystalfallsmgr@HOTMAIL.COM	City of Crystal Falls
felicel@MICHIGAN.GOV	Lisa Felice
mmann@USGANDE.COM	Michigan Gas & Electric
mpolega@GLADSTONEMI.COM	City of Gladstone
rlferguson@INTEGRYSGROUP.COM	Integrys Group
lrgustafson@CMSENERGY.COM	Lisa Gustafson
tahoffman@CMSENERGY.COM	Tim Hoffman
daustin@IGSENERGY.COM	Interstate Gas Supply Inc
krichel@DLIB.INFO	Thomas Krichel
pnewton@BAYCITYMI.ORG	Bay City Electric Light & Power
Stephen.serkaian@lbwl.com	Lansing Board of Water and Light
George.stojic@lbwl.com	Lansing Board of Water and Light
jreynolds@MBLP.ORG	Marquette Board of Light & Power
bschlansker@PREMIERENERGYLLC.COM	Premier Energy Marketing LLC
ttarkiewicz@CITYOFMARSHALL.COM	City of Marshall
d.motley@COMCAST.NET	Doug Motley
blaird@michigan.gov	Dan Blair
mpauley@GRANGERNET.COM	Marc Pauley
ElectricDept@PORTLAND-MICHIGAN.ORG	City of Portland
gdg@alpenapower.com	Alpena Power
dbodine@LIBERTYPOWERCORP.COM	Liberty Power
leew@WVPA.COM	Wabash Valley Power
kmolitor@WPSCI.COM	Wolverine Power
ham557@GMAIL.COM	Lowell S.
AKlaviter@INTEGRYSENERGY.COM	Integrys Energy Service, Inc WPSES
BusinessOffice@REALGY.COM	Realgy Energy Services
landerson@VEENERGY.COM	Volunteer Energy Services
Ldalessandris@FES.COM	First Energy Solutions
mbarber@HILLSDALEBPU.COM	Hillsdale Board of Public Utilities
mrzwiers@INTEGRYSGROUP.COM	Michigan Gas Utilities/Upper Penn Power/Wisconsin
djtyler@MICHIGANGASUTILITIES.COM	Michigan Gas Utilities/Qwest
donm@BPW.ZEELAND.MI.US	Zeeland Board of Public Works
Teresa.ringenbach@directenergy.com	Direct Energy
christina.crable@directenergy.com	Direct Energy
Bonnie.yurga@directenergy.com	Direct Energy
ryan.harwell@directenergy.com	Direct Energy
johnbistranin@realgy.com	Realgy Corp.
jweeks@mpower.org	Jim Weeks

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GEMOTION DISTRIBUTION SERVICE LIST

mgobrien@aep.com	Indiana Michigan Power Company
mvorabouth@ses4energy.com	Santana Energy
sjwestmoreland@voyager.net	MEGA
hnester@itctransco.com	ITC Holdings
lpage@dickinsonwright.com	Dickinson Wright
Karl.J.Hoesly@xcelenergy.com	Xcel Energy
Deborah.e.erwin@xcelenergy.com	Xcel Energy

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Resource Adequacy Listserve
Updated 11/30/2017

abalaskovitz@gmail.com
adella.crozier@dteenergy.com
agonzalez@nrdc.org
aheat@altelco.net
ajz-consulting@comcast.net
alise@switch.com
amason17@hotmail.com
anastasia.minor@dteenergy.com
angela.wojtowicz@dteenergy.com
annamunie@gmail.com
anne.geyer@enernoc.com
anne.uitvlugt@cmsenergy.com
athayer@meca.coop
bachmanj2@michigan.gov
beckl12@michigan.gov
becky@votesolar.org
benhbaker@gmail.com
bfrench@atcllc.com
binskeep@eq-research.com
blbeebe@dow.com
brian.madden@nexteraenergy.com
bruce.campbell@cpowerenergymanagement.com
bsoholt@windonthewires.org
bsowens@aep.com
bstafford@aee.net
bvanfarowe@mpower.org
byrnem@michigan.gov
camilo.serna@dteenergy.com
carrie.hitt@nexteraenergy.com
carter@rangerpower.com
catherine.wilson@cmsenergy.com
cborr@meca.coop
chris.hendrix@texasretailenergy.com
chris.iannuzzi@cmsenergy.com
Christina.hajj@dteenergy.com
clint.sandidge@calpinesolutions.com
cmonhart@energyalliancegroup.org
colec1@michigan.gov
corbins@michigan.gov
cornfields@michigan.gov
cshinshaw@mpower.org
cyndiroper@gmail.com
cynthia.brady@constellation.com
dafowler@varnumlaw.com

dan@mieibc.org
daniel.mahoney@dteenergy.com
dannyjmcgee@gmail.com
david.forsyth@gerdau.com
david.pettit@lw.com
dbinkley@itctransco.com
dburks@glenergy.com
ddasho@cloverland.com
deborah.e.erwin@xcelenergy.com
dennis.mullan@dteenergy.com
djester@5lakesenergy.com
dmderricks@integrysgroup.com
dmuchmore@honigman.com
docket@prquinlan.com
dohertyr1@michigan.gov
donofriol@michigan.gov
doug.stinner@fcagroup.com
drew.miller@enernoc.com
durianh@michigan.gov
dwalters@ghblp.org
dwayne.pickett@constellation.com
ebooth@covanta.com
emma.nix@pjm.com
epardini@pscinc.com
ethan.case@ccrenew.com
eubanksr@michigan.gov
ezuckerman@schlegelassociates.com
freemana5@michigan.gov
gambach@seventhwave.org
gary.melow@michiganbiomass.com
ggoss@jrsusa.com
glennfoy@yahoo.com
gouldk1@michigan.gov
gstebbins@energyfuturesgroup.com
hagamandj@bv.com
hansere@michigan.gov
hayes@mackinac.org
hazzard4335@gmail.com
heather.rayl@cmsenergy.com
heidi.myers@cmsenergy.com
hvigil@dykema.com
jaault@gomega.org
james.mitchell@lbwl.com
james@cisco.com
jamie.ormond@gmail.com
janiszewskij2@michigan.gov
janssenb@michigan.gov

jasonlnheath@gmail.com
jastoutenburg@dow.com
jeff.clark@ems.schneider-electric.com
jeff.downing@domtar.com
jennifer.dennis@semcoenergy.com
jgeer@michamber.com
jhammons@elpc.org
jharrison@uwua.net
jheston@fraserlawfirm.com
jlanglois@bomadet.org
john@michiganchemistry.com
jowen@wppienergy.org
jrice@cherrylandelectric.coop
jscripps@5lakesenergy.com
jseperic@outlook.com
jtomich@eenews.net
julie.voeck@nexteraenergy.com
jwbeattie@cmsenergy.com
jweeks@mpower.org
kadarkwa@itctransco.com
kaitlyn@instituteforenergyinnovation.org
kandlerb@rwca.com
karen.wienke@cmsenergy.com
kboothman@5lakesenergy.com
keith.troyer@cmsenergy.com
kelley.thomas@siemens.com
kenneth.piers@gmail.com
kkilpatrick@energyalliancegroup.org
kkorpi@michiganforest.com
kmyersbe@tclp.org
krizanj@romi.gov
krolling@midcogen.com
ktheath@heelstoneeenergy.com
lachappelle@varnumlaw.com
lclark@5lakesenergy.com
levasseur@fischerfranklin.com
ljbrooks@loomislaw.com
lsherman@5lakesenergy.com
lungerj@grandrapids.org
mark.barmasse@arcadis.com
mbarber@hillsdalebpu.com
michael.torrey@cmsenergy.com
mkearney@elpc.org
mkurta@karoub.com
mmpeck@fischerfranklin.com
mnofs@senate.michigan.gov
moodym2@michigan.gov

mpattwell@clarkhill.com
navneet.trivedi@vrindainc.com
ndreher@mwalliance.org
nicholas.griffin@dteenergy.com
nick.papanastassiou@enernoc.com
nluckey@invenergyllc.com
novakt4@michigan.gov
npurcell@ecoworksdetroit.org
nsoberal@umich.edu
patrickj5@michigan.gov
paul.eory@lbwl.com
phil.rausch@hscpoly.com
philip.w.dennis@dteenergy.com
pmartindale@baycitymi.org
polip@michigan.gov
raaron@dykema.com
rajan.telang@dteenergy.com
randy@prismpowerpartners.com
rchandler@sempraglobal.com
rcoy@clarkhill.com
rejji.hayes@cmsenergy.com
richard.mathias@pjm.com
rickwilson@peninsula-solar.com
rittenhousea@michigan.gov
rkonidena@misoenergy.org
rmccormack@invenergyllc.com
roseberryj@michigan.gov
roswald@pureeco.com
rsistevaris@aep.com
rstudley@house.mi.gov
rwilliamson@clarkhill.com
saarin1@michigan.gov
salas_jeff@yahoo.com
sarah.jorgensen@cmsenergy.com
sgomberg@ucsusa.org
shannon.weigel@edisonenergy.com
sicilianocj@gmail.com
simoncl@michigan.gov
sjwestmoreland@gomega.org
slaugh35@gmail.com
smjansen@midamericanenergyservices.com
soria.talbot@nee.com
spayer@energyalliancegroup.org
srantala@energymarketers.com
stephanie.tsao@spglobal.com
stephen.lindeman@dteenergy.com
steve.brooks@versoco.com

steve.stubitz@citadel.com
steved@sesnet.com
steven.gaarde@cmsenergy.com
talbergs@michigan.gov
teresa.ringenbach@directenergy.com
thanrahan@wppienergy.org
theresa.uzenski@dteenergy.com
timothy.a.hoffman@cmsenergy.com
tjlundgren@varnumlaw.com
tking@wpsci.com
toni.noakes@cmsenergy.com
trainwater@developmentpartners.com
tutsock@svsu.edu
tweeks@mpower.org
vee@dwej.org
wardin@midweststrategy.com
winston.feeheley@dteenergy.com
wrlcapgrp@aol.com
zach.halkola@pmpowergroup.com
zanderson@wpsci.com