Standby Rate
Working Group
Supplemental Report

PREPARED BY:
MICHIGAN PUBLIC SERVICE COMMISSION STAFF

MPSC Case No. U-17735

June 2017
Introduction

To satisfy the need for electric reliability, self-generation customers rely on utility services for backup, supplemental and maintenance power.¹ These utility services are generally referred to as standby service² and the rates are based on the utility’s costs for being ready to serve a load that is otherwise supplied by a customer’s generator as well as the cost of any energy actually delivered by the utility to the customer pursuant to standby service. Michigan Public Service Commission staff (staff) issued a report on standby service and the activities of the Standby Rate Working Group (SRWG) on August 19, 2016. The report was primarily focused on how Consumers Energy’s (Consumers) and DTE Electric’s (DTE) standby rates function with a primary focus on solar self-generation.³ This supplemental report will highlight the SRWG’s findings related to non-intermittent standby service tariff design and present staff’s recommendations on standby service tariffs for both combined heat and power (CHP) and solar self-generation.

The overarching goal of the SRWG is to ensure that any resulting standby service tariffs are based on the cost to serve self-generation standby customers and to increase transparency of the tariffs. Standby service tariff transparency doesn’t necessarily mean that the tariffs must be simplified, but the tariffs must include clear and concise definitions of the terms and billing determinants used within the tariff and all of the rate information necessary to calculate a monthly bill must be clearly shown. While actual changes to the standby service tariffs can only be accomplished through the Commission’s rate case process, this report will provide information on

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¹ Backup power means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility. Supplemental power means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself. Maintenance power means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility. (From PURPA)
² Also referred to as partial requirements service.
³ Detailed explanations of current standby service tariffs for both Consumers and DTE are included in the August 19th Report.
the SRWG’s investigation (primarily focused on Consumers and DTE tariffs with some limited discussion of Upper Michigan Energy Resource Company (UMERC) and Upper Peninsula Power Company (UPPCo) tariffs) into how existing standby service tariffs function and issues explored by the group. Staff’s recommendations are presented in the conclusion and recommendations section of the report.

To help staff prepare this report, in addition to the five in-person workgroup meetings held, the SRWG provided comments to highlight important aspects of the SRWG’s activities. Comments were received from the following:

1. Alliance for Industrial Efficiency
2. Association of Businesses Advocating Tariff Equity (ABATE)
3. Consumers Energy (Consumers)
4. DTE Electric (DTE)
5. Electricity Users Resource Council
7. Midwest Cogeneration Association and the Great Plains Institute (MCA/GPI)

A draft version of this report was provided to the SRWG in May 2017. Comments were received from ABATE, Consumers, DTE, MCA/GPI and MIEIBC. Copies of all comments on the draft report are included as Appendix D.

Staff thanks all of the commenters and finds the information provided helpful in understanding the different CHP perspectives and notes that this report draws on many of the comments provided.

Currently effective standby service tariffs are provided in Appendix A:

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4 SRWG comments submitted prior to the draft report preparation are provided on the workgroup website: http://www.michigan.gov/mpsc/0,4639,7-159-16377-47107-376753--,00.html
Consumers: General Service Self Generation Rate - GSG-2
DTE: Rider 3
UMERC (WPSC Rate Zone): Large Commercial & Industrial Service Cp-1M (Standby Provision)
UPPCo: Large Commercial & Industrial Service Cp-U (Standby Provision)

**Cost of Service Rate Class**

A question that arose during the SRWG discussions was whether it was more appropriate to assign baseload-type, non-intermittent, standby service customers to a separate rate class for purposes of determining the cost of service rather than including such customers in their supplemental service rate class for ratemaking purposes. Once the costs are assigned to the cost of service rate class, rate design within the cost of service class is used to develop the standby service tariffs and prevent intra-class subsidies. **Figure 1** depicts the traditional ratemaking process.
One factor to consider when deciding whether to establish a new cost of service rate class is the number of customers expected to be in the class. Currently, both Consumers and DTE have very few customers taking standby service. **Figures 2 and 3** show the number of customers taking standby service and the generator types from both utilities. It might be desirable to promote homogeneity within any new standby cost of service rate class by including only non-intermittent generator types such as biomass, waste-to-energy, hydroelectric, and cogeneration.

Source: MPSC Staff, Cost of Service Ratemaking Presentation to the Solar Working Group, March 18, 2017
Figure 2: Consumers GSG-2 Summary Data

GSG-2 Customers, MWH and MW

GSG-2 Facilities by Type

GSG-2 MWH Sales by Type

GSG-2 MW by Type

Biomass  Wind  Power Plant  Cogen

Figure 3 – DTE Rider 3 Summary Data

2013 Historical Data

Number of Customers - 40

R3 Sales ~ 100 GWh, 0.2% DTE Electric Sales

R3 Revenues ~ $8M, 0.2% DTE Electric Revenue

Generating Stations  Waste to energy  Dynamometers  Cogeneration  Non-cogeneration
The SRWG discussed DTE’s power supply cost of service model which includes a class called “D11 and Other” that includes Rider 3 customers. Rate D11 is the supplemental service rate for nearly all DTE standby service customers. Based on previous revenue allocations, historically 99% of the cost of service has typically been assigned to D11 and 1% to Rider 3. Several SRWG participants expressed interest in reviewing this allocation and making any necessary adjustments to update the allocation mechanism.

Standby service customers have historically been kept within a larger rate class for the cost of service study as the characteristics of standby customers are similar to the larger class and there may not be enough standby service customers to warrant a separate class. DTE’s standby rate is a rider that has rates coordinated with the supplemental service rate. An example given by DTE in the rate case is that “…the amount by which a customer’s supplemental demand on Rate D11 is below their maximum D11 on-peak supplemental demand, reduces the customer’s Rider 3 daily on-peak demand. This rate interaction lowers the customer’s daily demand charges and is just one example of why Rider 3 and Rate D11 should be viewed together as one cost of service class.” In almost all cases, DTE standby service rate customers with large cogeneration facilities take supplemental service under Rate D11.

Several SRWG participants commented that standby service customers should be studied in their own separate cost of service class so that the load and capacity and energy coincidence factors can be recognized and factored into the rates.

In the first quarter of 2017, the Commission issued rate case orders for both Consumers and DTE. DTE is directed to treat its standby service customers as a separate rate class for the

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5 See DTE’s Exceptions in U-18014 [http://efile.mpsc.state.mi.us/efile/docs/18014/0280.pdf](http://efile.mpsc.state.mi.us/efile/docs/18014/0280.pdf) page 102
purposes of the cost of service study in the next rate case, though this does not mean these customers should be in a separate rate class for the rate design. Consumers is directed to file a study that compares power supply revenue from Rate GSG-2 (standby service) customers to power supply costs caused by these customers, in order to determine whether current demand charges reflect the cost to serve standby customers. Establishing that the costs allocated to standby customers are cost of service-based will build the foundation for developing an effective rate design and standby service tariff. Rate design will parse out differences in costs imposed by individual customers such as those with CHP systems.

5 Lakes Energy – ConEd CHP Data Analysis

MCA/GPI asked 5 Lakes Energy to undertake an analysis of typical cogeneration customer standby service coincidence utilizing the continuous operating data collected by the New York State Energy Development Agency (NYSERDA) in its unique, long-standing cogeneration database. 5 Lakes Energy analyzed two years of 8760 hourly NYSERDA CHP data from the ConEd program for 19 CHP projects which included health care, industrial, multi-family residential, retail, and educational customers. On October 20, 2016, 5 Lakes Energy presented a summary of the analysis results and findings, including demand coincidence and recommendations for billing determinant accuracy. The summary slide from the presentation is shown in Figure 4. One of the key findings of the 5 Lakes Energy NYSERDA analysis was that the standby users’ demand variation was inconsequential based on ConEd’s overall load diversity. 5 Lakes Energy’s recommendation from that data was that no distinction between standby and supplemental power appears warranted. SRWG participants discussed the analysis, but did not reach consensus on the issue.
Rate Design - Key Elements of a Standby Service Tariff

The primary rate design elements typically included in a standby service tariff are Customer Charge, Generation Reservation Fee, Power Supply Demand Charge, Power Supply Energy Charge, Delivery Demand Charge, and Delivery Energy Charge. Each rate design element will be discussed below. The discussion will focus on Consumers’ and DTE’s current standby service tariffs. However, the analysis conducted by the SRWG is based on the previous versions that were in effect until the most recent rate case orders were issued.

Customer Charge

Self-generation customers taking standby service may also be taking supplemental service under their normal rate schedule. A customer’s normal rate schedule will include a monthly customer charge. Costs recovered via a monthly customer charge are based on longstanding

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7 See Jester October 20, 2016 presentation to SRWG, slide 14
Commission precedent and are directly related to the costs of attaching a customer to the system. Such costs include the meter, overhead and underground services, customer accounting costs, and customer service expenses. A utility may experience additional metering and administrative costs in the course of providing standby service, potentially making it appropriate to include a separate customer charge on the standby service tariff. DTE’s Rider 3 includes an additional customer charge which varies from $95 to $375 per month based on the service voltage. The supplemental rate most often paired with Rider 3 is D11 which has a customer charge of $275 or $375 based on the service voltage level (levels 1-3). Consumers’ GSG-2 tariff features a $100 system access charge for projects where the generator does not meet or exceed load and $200 for all others. In addition, the normal rate schedule for most GSG-2 customers is GPD which has a system access charge of $200. Staff recommends that customer charge amounts be reviewed by interested parties in the next rate cases.

Generation Reservation Fee

A generation reservation fee (also called a capacity reservation charge) is used in rate design on some standby service tariffs. A generation reservation fee is a charge to compensate the utility for the capacity that the utility must have available to serve a customer during an unscheduled outage of the customer’s self-generation unit.8 Standby service tariffs without a generation reservation fee are designed to recover capacity costs through the use of a demand charge. It may be appropriate to design the generation reservation fee so that it incorporates the forced outage rate of the generator.9 One way to do this is to base the fee on the forced outage rate of the highest

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9 Forced outage rate is the percent of time a generation unit is unavailable due to unplanned outages. See 21st Century Energy Plan Appendix II.
performing generators taking standby service. ABATE commented that it is best to not have a reservation charge at all, but if there is, it should be based on no more than one day’s, or one on-peak day’s, worth of daily or on-peak daily demand charges.

The Rate D11 Primary Supply Rate Power Supply Demand Charge is $15.79 per kW of on-peak billing demand (based on the highest 30 minute on-peak billing demand, must be at least 65% of the previous June – October billing demand). Rider 3, DTE’s standby service tariff, has a Monthly Generation Reservation Fee of $1.94 which is multiplied by the standby contract capacity in kW. Standby Contract Capacity has a lengthy definition in the tariff (attached as Attachment A). (To reduce complexity for this discussion, the nameplate capacity of the generator multiplied by the forced outage rate is assumed.)

The monthly generation reservation fee is 12% of the Rate D11 on-peak power supply demand rate ($1.94/$15.79). Excluding off-peak days which are weekends and holidays, each month has roughly 20 on-peak days. Twelve percent of 20 on-peak days is 2.4 days. Under Rider 3, at a minimum, the rate is designed to ensure that standby customers are paying for 2.4 days of on-peak capacity during a month when they have no generator outages. MCA/GPI point out that DTE’s reservation fee results in a minimum charge which is equivalent to a 12% outage rate, while the 2004 Oak Ridge National Laboratory Report\textsuperscript{10} MCA provided to the SRWG found that cogeneration systems, at the time of the report data collection, averaged a 5% forced outage rate. DTE is not necessarily over-recovering costs because the rate is designed so that the total capacity costs to be recovered are spread between the generation reservation fee and the capacity demand charge. The SRWG discussed what contribution to capacity standby customers should make during a month with no outages. No consensus was reached. Some participants said that standby rates

should be set up to incentivize standby customers to maintain and operate their generators to minimize outages by not having a generator reservation fee or setting the fee equal to one day’s on-peak usage. They point out that all necessary costs can be recovered from standby customers by increasing the standby capacity demand charge which would result in customers with lower performing generators paying more, and customers with higher performing generators paying less. Some SRWG participants said that a generation reservation fee equivalent to more than one day’s outage creates a subsidy from higher performing generators to lower performing generators.

However, a question that arose from the SRWG discussion was whether the value of incentivizing standby customers to operate their generators as efficiently as possible made it appropriate for the standby service tariff to be designed such that customers with high performing generators make no contribution to capacity costs during a month when no standby service is taken. Consumers’ GSG-2 standby service tariff does not include a generation reservation fee.

Power Supply Standby Charges - Demand

Power supply standby charges are paid by standby customers when they take standby service. These charges typically have on-peak demand (based on kW). The purpose of this charge is to recover costs for the capacity used by the customer.

DTE’s Rider 3 has a Power Supply Demand Charge equal to $5.09 per kW per day based on the highest 30 minute period on an on-peak day when standby service is taken.¹¹ For comparison purposes, the full service tariff, D11 has a Power Supply Demand Charge of $15.79 per kW of monthly maximum on-peak billing demand. There are several waivers on the tariff that cap the demand charge according to the scenario:¹² Standby Power is defined in the tariff:

Standby Demand is electric capacity provided by the Company to serve the

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¹¹ The rate is reduced to $2.88 per kW per day during pre-scheduled maintenance periods provided for in the tariff.
¹² See DTE’s March 14, 2016 presentation to the Standby Rate Working Group, slides 16 & 17. Rates shown have been updated in a subsequent rate case.
customer’s total internal load which would have been provided by the customer’s generation had it operated at its contract capacity less any reduction the customer can accomplish by reducing the supplemental demand at the time of the daily on-peak standby demand below the maximum monthly on-peak supplemental demand but not less than zero.

This option to reduce supplemental demand provides flexibility by enabling the customer to manage their monthly bill by reducing their total demand and the impact on the utility’s capacity during a generator outage.
Figure 5: DTE Rider 3 Standby Capacity Charge Calculation13

Standby Capacity Charges recover DTE’s costs of having generating resources available to serve load that is normally served by the customer’s generator.

There are three standby capacity calculations performed to determine the monthly capacity charge for customers on demand rates; 1) the monthly generation reservation fee; 2) the sum of the daily demand charges, and; 3) the daily demand cap. The monthly generation reservation fee is the minimum charge amount and the daily demand cap is the maximum charge amount.

The current monthly generation reservation fee is $1.75/kW/month applied to Standby Contract Capacity.

- Daily demands are determined based on the daily standby demand coincident with the highest 30-minute on-peak DTE Supply demand to the site. The current daily on-peak demand charge of $4.67/kW/day (or $2.60/kW/day during approved maintenance periods) is applied to each daily demand. The sum of the daily demand charges are compared to the minimum and maximum charge amounts to determine what charge to apply.

The daily demand cap is determined as the D11 Power Supply Demand Charge of $14.65/kW times the maximum standby capacity utilized, plus the Generation Reservation charge times the difference between the total standby contract capacity and the maximum standby utilized.

Example:

Customer’s generator with a SCC of 1,000kW was down for five on-peak days during month (unscheduled outage)

a) Generation Reservation Fee = 1,000kW x 1.75/kW/month = $1,750

b) Sum of the Daily Demands = 1,000kW x $4.67/kW/day x 5 days = $23,350

c) Daily Demand Cap = 1,000kW x $14.65 = $14,650

For this month the customer is billed the Daily Demand Cap
The group discussed that the Rider 3 daily on-peak backup demand charge is $5.09 per kW per day which is 32% of the full service power supply demand charge of $15.79. After three full, on-peak outages during the month, the standby customer is paying the full service rate power supply demand charge. There is not agreement among the group about the appropriate ratio of daily demand cap to daily demand. Some members of the SRWG recommended prorating the full-service demand charge by the number of on-peak days (or to reduce complexity, 20 on-peak days in every month could be assumed as previously discussed) in the month and making the charge a daily demand charge.

Consumers’ GSG-2 standby service tariff bases the power supply standby capacity charge on the “…highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries.” The contract setting this rate is currently the Company’s power purchase agreement with the Palisades nuclear plant. The actual capacity rate is not easily obtainable as the contract terms are redacted and its use is less transparent than if the rate was based on a source that could be shown on the tariff. Consumers correctly points out that there are only eight customers on the GSG-2 tariff and that there has been limited interest by potential customers. The capacity charge is prorated by the number of on-peak days in the month. In effect, Consumers’ tariff provides a daily demand charge for capacity. The company has proposed basing the power supply capacity charge on its embedded costs in the currently pending rate case.

If a customer has contracted for a specific amount of supplemental service, it is a benefit to the distribution system if the customer is able to reduce their load. Staff recommends that this customer load reduction should be incentivized by charging the customer for standby service only for the incremental load above the supplemental contracted amount or the largest net demand the customer places on the system. Staff acknowledges the complexity of doing this.
Power Supply Standby Charges – Energy

The energy charge is based on the number of kWh taken by the customer under standby service. DTE’s Rider 3 customers taking supplemental service under D11 pay the D11 energy charges for kWh taken during the month. In the past, for a limited time period, DTE Rider 3 customers had the option to pay for energy based on the MISO wholesale market. This option was discontinued due to a lack of cost justification in a previous rate case order issued on December 15, 2015 in Case No. U-17767.

Under Consumers’ GSG-2 standby service tariff, customers pay for energy according to the MISO Real-Time Locational Marginal Price for the Company’s load node plus a market settlement fee of $0.002/kwh. Consumers commented that this rate cannot be known in advance and reduces the transparency of the standby service tariff. In a future rate case, the Company commented it will propose an energy rate that is reflective of the cost to provide service and also easy for the customer to understand.

Delivery Standby Charges

Delivery charges are meant to recover the utility’s cost of the distribution system and other delivery-related costs not included in the monthly customer charge. These costs are allocated to the class based on the non-coincident class peak.\(^{14} \) For Consumers’ standby customers, delivery demand charges are generally based on the highest output of the generator with the generator nameplate capacity setting the maximum limit. Presumably, the amount can never be more than the customer’s peak load without the generator, although this is not stated in the tariff. It is not clear on the tariff how this amount would be established for a solar generator.

The delivery standby charges for DTE Rider 3 customers are based on the standby contract

\(^{14}\) Non-coincident class peak is the peak of the rate class (D11 & Other rate class for example) and not related to the utility’s overall system peak or customer’s individual peak.
capacity which is set according to 4 options. Generally, generators that operate on-peak as base load, have standby contract capacity based on the 1001st highest ½ hour of operation during June through October. Standby contract capacity for thermal load following generators or a solar generator would be set by mutual agreement between the Company and customer.

The Electricity Consumers Resource Council commented that the delivery demand charge should be based on the largest net demand, comprised of supplemental and standby demand, the customer places on the system.

Now that more information is known about solar generation profiles on a seasonal and daily basis, the Company may be able to provide more information about how solar standby contract capacity might be determined on the tariff.

2016 Public Act 341

Section 6v of PA 341 addresses the Public Utility Policies Act of 1978 and Michigan’s implementation. The new law directs the Commission to issue an order every five years that does the following:

(4) An order issued by the commission under subsection (1) shall do all of the following:
   (a) Ensure that the rates for purchases by an electric utility from, and rates for sales to, a qualifying facility shall, over the term of a contract, be just and reasonable and in the public interest, as defined by PURPA.
   (b) Ensure that an electric utility does not discriminate against a qualifying facility with respect to the conditions or price for provision of maintenance power, backup power, interruptible power, and supplementary power or for any other service.
   (c) Require that any prices charged by an electric utility for maintenance power, backup power, interruptible power, and supplementary power and all other such services are cost-based and just and reasonable.

Staff recommends that standby service tariffs be addressed in a rate case wherever possible.

For utilities that do not have rate cases within a five year time span, the Commission would
have the option to combine the standby service tariff review activity with the avoided cost review.

**Standby Service Tariff Complexity**

At the beginning of the process, one of the staff goals was to simplify the standby service tariffs and make it easier for current standby service customers to understand the billing calculations and how their bills could be reduced. Another goal is for potential standby service customers to be able to fully evaluate how their utility rates will change if they undertake a self-service generation project. Transparency in rates is frequently mentioned by SRWG participants. Staff defines rate transparency as a tariff that is reasonably understandable and includes information needed to calculate a customer bill. Standby service tariffs are very complex, and staff realized early in the SRWG process that a cost of service based standby service tariff can only be simplified to a certain point. The MIEIBC commented that it is important that the rates are transparent in order to facilitate the ability of companies to determine whether CHP is appropriate. MIEIBC’s comments included the following “…in the absence of transparency around rates, many potential applications never even get serious consideration…The integrated resource planning (IRP) process under Public Act 341 requires consideration of projected energy and capacity purchased from a cogeneration resource…In order to accurately assess contributions of CHP in an IRP process, transparency in standby rates is essential.”

The Alliance for Industrial Efficiency pointed out that Michigan has 87 CHP sites, with a total capacity of 3,389 MW.15

The Department of Energy estimates the state has 4,987 MW of remaining CHP and WHP technical potential capacity (identified at 10,370 sites), with 2,170

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MW of remaining onsite technical potential in the industrial sector alone.\textsuperscript{16} A 2016 report from the Alliance for Industrial Efficiency found that if an economically-viable portion of the state’s CHP and WHP was deployed,\textsuperscript{17} Michigan industrial sector customers would save $2.27 billion on electricity costs from years 2016 to 2030. These cost savings result from increasing CHP and WHP deployment alone, demonstrating the importance of CHP to increasing manufacturing competitiveness.\textsuperscript{18}

The MCA/GPI take the position that standby service tariffs should be unbundled but need not be overly complex and provided a conceptual Model Tariff for discussion which is attached as Appendix B. MCA/GPI’s Model Tariff includes four key elements: Customer Charge, Reservation Fee, Demand Charge and Energy Charge. (Michigan utilities may have demand charges for both power supply and delivery.) The Model Tariff describes MCA/GPI’s best practice approaches for these key tariff elements. MCA/GPI recommended that the Commission require each utility to translate their tariff charges into a one-page “Summary of Charges” table clearly showing the tariff rates for each key element of the tariff. In the SRWG process, MCA/GPI offered two examples of such a table in Ameren Missouri’s standby rider and Otter Tail Power’s ‘standalone’ standby tariff.

During the course of the SRWG, both Consumers and DTE refined their processes for working with customers interested in self-generation. DTE’s process includes the customer contacting their account representative for guidance. The company said that several customers have recently availed themselves of this service. Consumers commented that, during 2016, it has worked closely with more than a dozen customers who are evaluating self-generation projects. Staff has participated in several calls with an interested customer’s project developer and the utility as part of

\textsuperscript{17} Percentage of Michigan’s technical potential for CHP with less than 10-year payback period.
\textsuperscript{18} Alliance for Industrial Efficiency comments, page 2.
this process. While these processes involving a customer account representative are helpful, especially when a project is further in the development process, CHP project developers need to be able to understand the standby service tariff well enough to run some initial economic evaluations to determine whether the customer is a reasonable candidate for a project. Increased transparency in the tariff will be helpful for these early screening analyses.

Both Consumers and DTE are supportive of making standby service tariffs easier to understand by providing more descriptive information on the tariff and also adding sample calculations on their websites.

**Standby Service Tariff Fairness**

The primary impetus for the SRWG was to research whether the standby service tariffs are fair. Fairness has been defined as basing the standby service tariff on cost of service principles and incorporating rate design to send appropriate price signals for customers to operate their generators efficiently. One fairness concept that was brought up consistently was whether the standby service tariffs are designed with the assumption that all generators are experiencing an outage at one time. Making this assumption would mean that standby customers are paying for standby capacity based on the full amount of contracted standby capacity for the entire class of standby service customers (the highest expected output of the generator in cases where the generator size is less than the site load). DTE commented that Consumers’ and DTE’s standby service tariffs are not designed that way and doing so would be a violation of PURPA. Consumers explained they use the historical contribution of the standby service customers to assign cost and design rates for standby service customers. Doing so provides the benefit of generator diversity and does not base the costs on the assumption that all generators are experiencing an outage at once. DTE has a different approach
which relies on previous revenue allocations, historically 99% of the “D11 and Other” rate class cost of service has typically been assigned to D11 and 1% to Rider 3. The appropriateness of this cost split is expected to be addressed in DTE’s current rate case (U-18255). The fairness of standby service tariffs should be reviewed and considered in future rate cases.

Standby Service Tariff Comparisons

The Midwest Cogeneration Association completed a study comparing standby service tariffs for seven Midwestern utilities, Consumers and DTE. The study included five scenarios evaluated on a single-month basis:

- no generator outage
- one scheduled outage 16 hours on-peak
- two scheduled outages 8 hours on-peak and 8 hours off-peak
- one scheduled outage 32 hours on-peak
- one unscheduled outage 16 hours (8 on-peak, 8 off-peak)

The full results of the study are presented in Appendix C and a summary is shown in Table 1. It is difficult to compare standby service tariff charges because the tariffs are complex and the selected scenarios may not reflect actual operating characteristics of generators taking service under the standby service tariff on the utility’s system and differences between utility customer composition, average customer usage and average cost per kWh. Nevertheless, staff believes there is value in this type of comparison study. For the study to have maximum value, the data and inputs were vetted by the SRWG. When the study results were first reviewed, there was concern that the comparison might not be incorporating all of the nuances of the tariffs. Specifically, some states or utilities may have goals other than achieving cost of service based rates, such as incentivizing certain types of distributed generation. As an example of a tariff nuance, DTE pointed out that while a generator’s nameplate capacity was used in each of the tariff scenarios, their tariff is based
on the 1001st highest half-hourly kW output towards internal load which could be 30% less than nameplate. The MCA fine-tuned the study and presented the results to the SRWG. Both Consumers and DTE commented that this type of benchmarking is important, but more research is needed to determine whether the comparisons are truly on an “apples-to-apples” basis. They point out that some state jurisdictions may have policy goals that might impact whether the standby service tariff is structured to fully collect costs from each rate class. Factors identified include whether the rate is a negotiated rate, subsidized, includes interruptible components or whether certain charges are recovered as part of the supplemental rate.

After the SRWG’s final in-person meeting, 5 Lakes Energy worked with two Upper Peninsula utilities, UMERC and UPPCo, to add their standby service tariffs to the comparison. Due to the timing of the UMERC and UPPCo standby calculations, the SRWG did not have the opportunity to vet the UMERC and UPPCo data, but the calculations are included in Table 1.

Table 1: Comparison of Standby Service Tariff Rates for Four Michigan Utilities\textsuperscript{19,20}

<table>
<thead>
<tr>
<th>Scenario Description</th>
<th>Consumers</th>
<th>DTE</th>
<th>UMERC</th>
<th>UPPCO</th>
</tr>
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<tbody>
<tr>
<td>No Outage</td>
<td>8,300</td>
<td>10,535</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Scheduled Outage 16 Hours Off-Peak</td>
<td>9,246</td>
<td>11,657</td>
<td>2,218</td>
<td>2,911</td>
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<tr>
<td>Scheduled Outage 16 Hours On-Peak</td>
<td>11,645</td>
<td>18,653</td>
<td>3,098</td>
<td>3,883</td>
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<tr>
<td>Scheduled Outage 8 Hours On-Peak, 8 Hours Off-Peak</td>
<td>11,191</td>
<td>13,405</td>
<td>2,658</td>
<td>3,397</td>
</tr>
<tr>
<td>Scheduled Generator Outage 32 Hours On-Peak</td>
<td>14,833</td>
<td>30,272</td>
<td>6,196</td>
<td>7,766</td>
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<tr>
<td>Unscheduled Outage 8 Hours On-Peak, 8 Hours Off-Peak</td>
<td>11,191</td>
<td>17,545</td>
<td>30,536</td>
<td>31,631</td>
</tr>
</tbody>
</table>

\textsuperscript{19} Based on 2,000 kW standby contract capacity with customer served at primary voltage level.

\textsuperscript{20} Details about each calculation for Consumers Energy and DTE Electric are available in the comments provided by MCA/GPI. UMERC and UPPCo calculation details are available in 5 Lakes Energy’s additional analysis.
Table 1 highlights the dramatic differences in standby service costs across the four studied utilities. Both UMERC and UPPCo have pro-rated demand charges for months where the customer experiences a scheduled outage. The scenario with the unscheduled 8 hour on-peak outage shows both UMERC and UPPCo with significantly higher monthly bills due to the fact that for unscheduled outages, the demand charges are not prorated and the customer pays a monthly “ratcheted” standby capacity demand charge. Both Consumers and DTE have pro-rated standby capacity demand charges. DTE has a higher daily on-peak demand charge for unscheduled outages. UMERC and UPPCo have no standby charges during the no-outage scenario while Consumers and DTE bill for standby capacity and distribution costs. Neither standby rate information nor the appropriateness of the standby service tariffs for UMERC and UPPCo were discussed by the SRWG.

**Conclusion & Recommendations**

The Standby Rate Working Group had the overarching goal to investigate standby service tariff rates. As a result of the group’s collaboration, we have developed a deeper understanding in the operation of the tariffs which has allowed staff to identify the recommendations provided in this report. Standby rate working group participants approach these rates from different perspectives, which contributed to a lack of consensus on recommendations. After reviewing meeting notes, presentations and comments provided by participants, staff developed a list of recommendations. Staff is greatly appreciative of the time and effort put into the SRWG collaborative process by all of the participants. Staff looks forward to a thoughtful and detailed review of all aspects of standby service tariffs by all interested parties as part of future utility rate cases.
Staff Recommendations

1. To assist with standby service tariff transparency, a clear and concise description of the tariff structure and each term used should be included with the tariff. Utilities should work with staff and stakeholders to ensure a good understanding of 1) the standby service tariff; 2) information available on the company’s website; and 3) the company’s preferred process for developers and customers to get standby service questions answered.

2. **Table 1** highlights the inconsistency in standby service tariffs across the state. Staff recommends that the Commission develop a cost-of-service-based, standardized framework for standby service tariffs where possible. Staff recognizes there may be reason to deviate from the standard. Any differences should be justified and supported by the company.

3. For customers taking both supplemental and standby service, the standby service tariff should be structured to allow the standby capacity and delivery demand charges to be structured to recognize the demand interactions between supplemental and standby service (net load).

4. Standby service tariffs, including the monthly customer charges, should be reviewed and, if necessary, updated in each utility’s rate case to ensure they are based on the most up-to-date cost of service principles. Daily capacity demand charges and the use of generator reservation fees and how the fee relates to the daily demand charge/pro-rated daily demand charges should be considered and discussed by the parties.

5. Standby service tariffs should include a reasonable capacity price differential to encourage scheduled maintenance, which in turn may reduce unscheduled outages. Limiting options to only off-peak time periods may not result in least cost to the utility.

6. Time of use charges for capacity and energy should be an available option for standby service customers.

7. The method for determining the solar standby tariff billing criteria should be made clear on the tariff. Customers with solar generators should have the option to stay on their supplemental service rate schedule provided it has a demand charge for delivery services. A time of use charge for capacity and energy should be considered for these customers.
Appendix A-Current Standby Service Tariffs
GENERAL SERVICE SELF GENERATION RATE GSG-2

Availability:

Subject to any restrictions, this rate is available to any Full Service Customer with a generating installation greater than 550 kW, which may employ cogeneration or small power production technology. A customer who meets the Federal Energy Regulatory Commission’s (FERC) criteria for a Qualifying Facility may elect to take standby service under this rate and may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy, should it be determined to adversely impact economic or reliable operation of the Company’s electric system. An eligible customer may elect to take service under this General Service Self Generation Rate GSG-2 or under Rule C11., Net Metering Program.

“Standby” service is defined as that electric service used in place of the customer's generation other than Company supplied firm service.

"Standby Capacity" is defined as the contracted kW capacity the Company is expected to provide to the customer on an occasional basis due to outages of the customer’s generating unit(s). The Standby Capacity shall not exceed the generator's capability as designated in the interconnection agreement and as determined by the Company.

“Standby Demand” is defined as the greater of the (i) highest 15 minute kW demand the Company supplies the customer for Standby Service during the current month or (ii) highest Standby Demand from the previous 11 months. The Company shall determine the amount of monthly Standby Demand supplied to the customer based upon the total amount of power supplied to the customer, their contract Standby Capacity and generator output.

The Company shall not be required to supply standby power to the customer in excess of their contracted Standby Capacity. However, the Company may, at the written request of the customer made at least thirty days in advance, permit an increase in Standby Capacity provided the Company has facilities and generating capacity available.

Self-generation customers who require Company delivery service for any portion of the load that has been self-generated will be charged as described under the Delivery Standby Charges as shown on this Rate Schedule for the service provided and charged for any Power Supply provided by the Company as described under Power Supply Standby Charges on this rate schedule.

This rate is not available to Retail Open Access.

Nature of Service:

All facilities operated in parallel with the Company’s system must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter all generation equipment. No refund shall be made for any customer contribution required under this Rate Schedule.

Interval Data Meters are required on all generators. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data/billing determinants necessary for billing.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Where service is supplied at a nominal voltage of 25,000 volts or less but equal to or greater than 2,400 volts, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

(Continued on Sheet No. D-43.00)
GENERAL SERVICE SELF GENERATION RATE GSG-2  
(Continued From Sheet No. D-42.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges

Power Supply Standby Charges

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer’s consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500. If the customer fails to meet this written notice requirement, the LMP shall be increased by applying a 10% adder.

Delivery Standby Charges

System Access Charge:

Generator that does not meet or exceed load: $100.00 per generator installation per month
Generator that meets or exceeds load: $200.00 per generator installation per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge: $4.92 per kW of Standby Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $2.07 per kW of Standby Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $1.14 per kW of Standby Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.
GENERAL SERVICE SELF GENERATION RATE GSG-2
(Continued From Sheet No. D-43.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Adjustment for Power Factor
This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor.
Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

<table>
<thead>
<tr>
<th>Power Factor</th>
<th>Penalty</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.800 to 0.849</td>
<td>0.50%</td>
</tr>
<tr>
<td>0.750 to 0.799</td>
<td>1.00%</td>
</tr>
<tr>
<td>0.700 to 0.749</td>
<td>2.00%</td>
</tr>
<tr>
<td>Below 0.700</td>
<td>3% first 2 months</td>
</tr>
</tbody>
</table>

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Substation Ownership Credit
Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand. The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(0.64) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(0.44) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Transmission Interconnect Credit
Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit: $(1.25) per kW of Standby Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

(Continued on Sheet No. D-45.00)
GENERAL SERVICE SELF GENERATION RATE GSG-2
(Continued From Sheet No. D-44.00)

Monthly Rate (Contd)

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Minimum Charge

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year.
STANDARD CONTRACT RIDER NO. 3  PARALLEL OPERATION AND STANDBY SERVICE AND  
STATION POWER STANDBY SERVICE

There are two categories of standby service provided under this rider, “STANDBY SERVICE” AND “STATION POWER STANDBY SERVICE”. STANDBY SERVICE applies to customers with generation facilities that are located within the Company’s retail service territory and directly interconnected with the Company. STATION POWER STANDBY SERVICE applies to customers with generation facilities that are located within the Company’s retail service territory and that are directly interconnected to ITC Transmission.

STANDBY SERVICE

STANDBY SERVICE: Available to customers with generation facilities that are located within the Company’s retail service territory and directly interconnected with the Company. Customers who desire the Company to serve the power supply requirements of load that is normally served by the customer’s generator or prime mover must take standby service under the provisions of this rider unless otherwise exempted by order of the Michigan Public Service Commission or by the provisions set forth below and must take supplemental service on one of the applicable filed rates listed below.

Customers purchasing their entire energy requirements from the Company with generators or prime movers installed for use only in emergency will not be considered as taking standby service.

Customers with generators or prime movers installed solely for use to provide a load for testing equipment such as regenerative dynamometers may elect not to purchase standby energy service for that equipment under this rider, must meet the applicable parallel operation requirement, must purchase power that would, absent this provision, be considered standby on another rate schedule and must take standby for any additional generating equipment normally site load.

APPLICABLE TO: General Service Rate Schedule Designation D3
Secondary Educational Institution Rate Schedule Designation D3.2
Interruptible General Service Rate Schedule Designation D3.3
Large General Service Rate Schedule Designation D4
Primary Educational Institution Rate Schedule Designation D6.2
Interruptible Supply Rate Schedule Designation D8
Primary Supply Rate Schedule Designation D11

PARALLEL OPERATION: The customer must meet the interconnection requirements of the Company specified in “The Michigan Electric Utility Generator Interconnection Requirements” as approved by the Commission, and must enter into an Interconnection and Operating Agreement with the Company before parallel operation will be permitted. Operating in parallel with the Company's system without written approval by the Company of the interconnection and any subsequent changes to the interconnection will make the customer subject to disconnection.

INDEMNIFICATION AND INSURANCE: Except for the acts or omissions of the Company's employees or agents which occur on the Customer's side of the point of interconnection the customer shall indemnify, defend and hold the Company and its officers, agents and employees harmless from any liabilities, claims, losses,

(Continued on Sheet No. D-68.00)
demands, costs, damages or damage which (i) occur on the Customer's side of the point of interconnection resulting from the installation, maintenance, possession or operation of the Facility, or (ii) occur on the Company's side of the point of interconnection up to the first point of the Company's General Facility Protection if at the time of the injury or damage, the Company is not providing electric energy to the customer and the injury or damage was caused by the customer's intentional defeat of the protective relays.

The Company shall indemnify, defend and hold the Customer and its officers, agents and employees harmless from any liabilities, claims, losses, demands, costs, damages or judgments, including reasonable attorneys' fees, arising out of all personal injuries or property damages which occur on the Company's side of the point of interconnection resulting from the installation, maintenance, possession or operation of the Company's General Facilities; (i) except for the acts or omissions of the Customer's employees or agents which occur on the Company's side of the point of interconnection; and (ii) except for those injuries or damages for which the Customer is to indemnify the Company pursuant to the preceding paragraph.

The Customer taking service under this rider shall maintain and furnish current evidence of comprehensive general liability insurance in the amount of $2,500,000 per occurrence. This insurance can be a combination of primary and excess insurance. The Company shall be named as an additional insured under the customer's policy. The customer need not provide insurance if it can demonstrate that its Tangible Net Worth as defined by GAAP is $8,000,000 or more and provides an affidavit to that effect signed by an authorized agent of the Company. If the customer fails to provide insurance or does not meet the requirements of the preceding sentence for waiver of insurance, then the Company will purchase insurance in the amount of $2,500,000 to protect the Company (but not the customer). The cost of such insurance will be paid by the customer. The customer's insurance, its waiver, or insurance purchased by the Company shall not limit the Customer's indemnity obligations. Parallel operation will not be permitted (or will be terminated) if the Customer fails to provide insurance, meet the waiver requirements or pay the cost of insurance obtained by the Company.

METERING REQUIREMENTS: All customers taking service under this rider must install the necessary equipment to permit metering. The Company will supply the metering equipment. The output of customer generation or, if appropriate, the load served by another source of power or the customer's prime mover, inflow from the Company and outflow to the Company if applicable will all be metered with demand-recording equipment by the Company.

STANDBY CONTRACT CAPACITY: Standby contract capacity in kW will be established for electric capacity sufficient to meet the customer's standby load. Unit sizes, number of units, site demands, operating characteristics and other factors impact the amount of electric capacity that is sufficient to meet the customer's standby load. Standby contract capacity will be established according to one of the following methods with the intent to use the method which best determines the electric capacity sufficient to meet the customer's standby load.

(Continued on Sheet No. D-69.00)
STANDARD CONTRACT RIDER NO. 3 (Contd.) PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE

(a) If the customer's generating units are electrically base loaded during peak hours the standby contract capacity for billing months that include periods from calendar months June through October will be set at the 1001st highest half-hourly kW output toward internal load during billing months that include periods from calendar months June through October over the latest 12-month period. The standby contract capacity for remaining billing months will be set at the 1001st highest half-hourly kW output during those months over the latest 12-month period. The standby contract capacity will be adjusted on an ongoing basis reflecting the current month and preceding eleven months.

“output toward internal load” means the simultaneous output of all units less excess generation flowing back through the interconnection to the Company’s system.

(b) If the customer's generating units are operated with the intent to provide energy to the system and standby is only required for site load during outages the standby contract capacity will be set at the maximum half-hourly demand provided to the facility.

(c) For customers with units that do not operate in parallel with the system but have the ability to connect load normally served by unmetered on site generation to the system during generation outages, (throw over standby), the standby contract capacity will be set at the maximum metered half-hourly demand thrown over to the system and supplemental demand will the metered inflow less the metered throw over load.

(d) For customers demonstrating unusual operating conditions, including but not limited to initial unit operation, unpredictable generation from renewable resource units or generation that follows thermal load and prolonged periods with no generation, standby contract capacity may be set by mutual agreement of the Company and the customer to levels sufficient to meet the customer's standby load.

STANDBY POWER: Standby energy is electric energy provided by the Company to serve the customer's total internal load which would have been provided by the customer's generation had it operated at its contract capacity. Standby demand is electric capacity provided by the Company to serve the customer's total internal load which would have been provided by the customer’s generation had it operated at its contract capacity less any reduction the customer can accomplish by reducing the supplemental demand at the time of the daily on-peak standby demand below the maximum monthly on peak supplemental demand but not less than zero.

SUPPLEMENTAL POWER: Supplemental power is electric energy and capacity provided by the Company to serve the customer's total internal load which is in addition to that portion of the customer's total internal load equal to the standby contract capacity. For each point of service, total internal load equals the output toward internal load of the customer's generation plus the power supplied by the Company. Supplemental demand equals total internal load less standby contract capacity, but not less than zero. Supplemental high on-peak demand used to establish Power Supply Demand will be highest supplemental demand from the dates and times at which the daily on-peak standby demands are set. Supplemental power will be billed under the applicable rate schedule for supplemental service ("supplemental rate schedule").

(Continued on Sheet No. D-70.00)
STANDARD CONTRACT RIDER NO. 3 (Contd.) PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE

RATES:

Power Supply Charges:
Monthly Generation Reservation Fee:
$1.94 times the standby contract capacity in kW, per month.

Demand Charges:
A daily on-peak standby demand charge will be charged based on the determination of standby power coincident with the daily highest 30-minute integrated reading during on-peak hours of the demand meters which measure the total load served by the Company. Standby demand equals standby contract capacity minus the 30-minute output toward internal load of the customer’s generator less any reduction the customer can accomplish by reducing the supplemental demand below the maximum monthly on peak supplemental demand, but not less than zero, and not greater than the total load served by the Company.

The daily on-peak backup demand charge is $5.09 per kW per day during periods other than maintenance periods as defined below.

The daily on-peak backup demand charge is $2.88 per kW per day during maintenance periods as defined below.

Energy Charge:
An energy charge for back-up and maintenance power will be charged based on standby contract capacity less the output toward internal load of the customer’s generator, but not less than zero. For customers served on supplemental rate schedules D4, D11, D6.2 and D8, the energy charge will be the D11 on-peak power supply energy charge, 4.330¢ per kWh, plus appropriate power supply credits, including but not limited to off-peak credit, and voltage level credit. For customers served on supplemental rate schedules D3, D3.2 and D3.3, the energy charge will be the applicable power supply energy charge specified in the customer’s supplemental rate.

The energy as stated herein, is also subject to provisions of the PSCR clause and other Surcharges and Credits Applicable to Power Supply as approved by the Commission. See Section C8.5.

Waivers and limits for demand/energy rates:
For customers taking supplemental service at demand/energy rates schedules D4, D11, D6.2 and D8, and customers switching from energy only rates to demand/energy/ rates, the following applies.

If the total of daily demand charges for the month is less than the monthly generation reservation fee, then the daily demand charges will be waived for that month.

If the total of daily demand charges for the month is greater than the monthly generation reservation fee, then the generation reservation fee will be waived for that month.

(Continued on Sheet No. D-71.00)
STANDARD CONTRACT RIDER NO. 3 (Contd.) PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE

If the total of daily demand charges for the month is greater than the Rider 3 Daily Demand Cap the customer will pay the Daily Demand Cap. For customers served on supplemental rates schedule D4, The Daily Demand Cap will be determined as the D11 Power Supply Demand Charge times the maximum standby contract capacity utilized plus the Rider 3 Generation Reservation Charge times the difference between the total standby contract capacity and the maximum standby utilized. For customers served on supplemental rates schedules D6.2, D8 and D11, the Daily Demand Cap will be determined as the D11 Power Supply Demand Charge times the maximum standby contract capacity utilized plus the difference between the product of the D11 Distribution Demand Charge times the standby contract capacity utilized and the standby Distribution Charge times the standby contract capacity utilized plus the voltage specific D11 Delivery Charge energy component applied to all standby energy delivered plus the Rider 3 Generation Reservation charge times the difference between the total standby contract capacity and the maximum standby utilized.

Waivers and limits for energy-only rates:
For customers taking supplemental service on energy-only rates for the entire billing cycle, schedules D3, D3.3, and E5, the following applies.

If the total of daily demand charges for the month is less than the monthly generation reservation fee, then the daily demand charges will be waived for that month.

If the total of daily demand charges for the month is greater than the monthly generation reservation fee, then the daily demand charges will be waived for that month provided that the supplemental rate continues as an energy-only rate. If not, then paragraphs (6)(b) and (6)(c) above will apply.

MAINTENANCE PERIODS: A customer may specify, subject to conditions below set by the Company, up to 20 on-peak days during a year as maintenance days. In addition standby daily demands on the day after Thanksgiving and on-peak days occurring during the period from December 24 through January 1 will be priced at the maintenance day rate specified above. A maintenance day is a calendar 24-hour day.

Conditions for setting maintenance days:
(a) The customer must request maintenance days in writing.
(b) The Company must receive the request at least 45 days before the first requested maintenance day.
(c) Requests will be honored according to the date received.
(d) Requests may be refused by the Company if they conflict with the Company’s own schedule of maintenance and expected demands. The Company will permit the customer to select alternative maintenance days.
(e) If there is a substantial change in circumstances which make the agreed upon schedule impractical for either party, the other party upon request shall make reasonable efforts to adjust the schedule in a manner that is mutually agreeable.

(Continued on Sheet No. D-72.00)
STANDARD CONTRACT RIDER NO. 3 (Contd.)  PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE

Delivery Charges:
Service Charge:
$275 per customer per month for customers served at primary voltage.
$375 per customer per month for customers served above primary voltage.
$95 per customer per month for customers served at secondary voltages.

Distribution Charge:
Distribution charges will be as follows:
$3.96 per kW at primary voltage applied to the standby contract capacity
$1.54 per kW at subtransmission voltage applied to the standby contract capacity
$0.73 per kW at transmission voltage applied to the standby contract capacity
For service provided in conjunction with a secondary voltage base rate the Delivery Charge will be the greater of $9.80 per kW applied to standby contract capacity or $3.920¢/kWh applied to all standby energy delivered.

Substation Credit: Available to customers served at subtransmission voltage level (24 to 41.6 kW) or higher who provide the on-site substation including all necessary transforming, controlling, and protective equipment. A credit of $0.30 per kW shall be applied to the distribution demand charge per kW of standby capacity. An additional credit of 0.040¢ per kWh of standby delivered will be given where the service is metered on the high voltage side of the transformer.

Surcharges and Credits Applicable to Delivery Service: As approved by the Commission. See Section C9.8.

ADJUSTMENT OF PRIOR RATCHETS: When a customer takes standby service under Rider No. 3, the setting or the increasing or decreasing of standby contract capacity will affect the existing ratchet levels on the supplemental rate as follows:

(a) An amount in kW equal to the initial standby contract capacity (or to the increase or decrease) will be subtracted from (or subtracted from or added to) the existing ratcheted maximum demand level for customers on supplemental rates D6.2 and D8 and D11.

(b) An amount in kW equal to 65% of the initial standby contract capacity (or of the increase or decrease) will be subtracted from (or subtracted from or added to) the existing ratcheted on-peak billing demand level for customers on supplemental rates D4, D6.2 and D8 and D11.

LATE PAYMENT CHARGE: See Section C4.8.

SCHEDULE OF ON-PEAK HOURS: See Section C11.

(Continued on Sheet No. D-73.00)
STANDARD CONTRACT RIDER NO. 3 (Contd.) PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE

POWER FACTOR CLAUSE: The rates and charges under this tariff are based on the customer maintaining a power factor of not less than 85% lagging. Customers are responsible for correcting power factors less than 70% at their own expense. The size, type and location of any power factor correction equipment must be approved by the Company. Such approval will not be unreasonably withheld. A penalty will be applied to the total amount of the monthly billing for supplemental and standby service for power factor below 85% lagging in accordance with the table in Power Factor Determination, Section C12. The penalty will not be applied to the on-peak billing demand ratchet nor to the minimum contract demand of the supplemental rate, but will be applied to metered quantities.

INTERRUPTIBLE STANDBY SERVICE:

(a) Interruptible standby service is supplied in conjunction with supplemental rates D8 and D3.3, provided that the customer qualifies for D8 or D3.3 under the provisions of the respective rates.

(b) For customers taking service on supplemental rate D8, the daily demand charge for back-up power and maintenance power will be waived on a day that the Company requests interruption, provided that the customer is assessed neither a non-interruption fee nor a non-interruption penalty under the terms of the D8 rates.

(c) For customers taking service on supplemental rate D3.3, the customer's generator, prime mover, or other source of energy must be connected only to the interruptible circuit. The energy charge for back-up power and maintenance power will be the same as the energy charge for the D3.3 rate. The daily demand charge will be waived on a day that the Company interrupts the circuit.

(d) Interruptible standby service will also be supplied in conjunction with any new interruptible supplemental rates approved by the Commission after January 1, 1989, under terms to be incorporated in this section.

SPECIAL TERMS AND CONDITIONS: Customer-owned equipment must be operated so that voltage fluctuations on the Company’s system shall not exceed permissible limits.

Upon the request of a customer, the Company will provide monthly reports of the data from the meters measuring the load served by the Company and the output of the customer’s generators, for a charge of $10.00 per report per month. Each report contains data from one meter.

Application of Rider No. 2 for redundant service for customers served under this rider will be the same as for customers without generating equipment.

Service under this rider will not be affected by ownership of the generation facility provided that: (1) the generation facility is located on the customer’s site, (2) the load served by the generation facility is on the same site, and (3) the total output of the generation facility is utilized by the customer or sold to the Company.

(Continued on Sheet No. D-73.01)
STANDARD CONTRACT RIDER NO. 3 (Contd.) PARALLEL OPERATION AND STANDBY SERVICE AND STATION POWER STANDBY SERVICE

CONTRACT TERM: The contract term is for a five-year period unless terminated by mutual consent and extending thereafter from month to month until terminated by mutual consent or by thirty day's written notice by either party.

DISPUTE RESOLUTION PROCEDURE: Any customer who disputes a determination or interpretation made by the Company under this rider may deliver a written notice of such dispute to the customer's service representative at the Company. The Company will respond to the notice in writing within 20 working days.

Disputes between the Company and the customer may be presented to the Commission for informal resolution.

Any customer who disputes a determination made by the Company under this rider may at any time file a formal complaint with the Office of the Secretary of the Commission.

(Continued on Sheet No. D-73.02)
STATION POWER STANDBY SERVICE

SERVICE UNDER THIS PROVISION BECOMES EFFECTIVE APRIL 1, 2014

STATION POWER STANDBY SERVICE: Available to customers with generation facilities that are located within the Company’s retail service territory and that are interconnected to ITC Transmission. The power supply requirements necessary to maintain and operate the generating facility that are normally served by the facility’s on-site generation but which instead are provided by the facility’s taking power through its transmission interconnection must be provided under the station Power Standby Service provisions of this rider.

APPLICABLE TO: General Service Rate Schedule Designation D3

HOURS OF SERVICE: 24 hours, subject to interruption by agreement, or by advance notice.

CONTRACT CAPACITY: Customers shall initially contract for a specified capacity in kilowatts sufficient to meet expected maximum requirements. Any single reading of the demand meter or aggregation of demand meters recording inflow to the facility in any month that exceeds the contract capacity then in effect shall become the new contract capacity.

METERING REQUIREMENTS: All customers taking service under this rider must install the necessary equipment to permit metering. The Company will supply the metering equipment. Service to the customer under this Rider will be metered with demand-recording equipment. Any equipment installed by the customer necessary to accommodate the Company’s metering equipment must be approved by the Company and must be compatible with the Company’s Meter Data Acquisition System.

RATES:

Power Supply:
Station Power Energy Service will be priced on the basis of the real time MISO locational hourly marginal energy price for the Company-appropriate load node. In additional to the MISO locational hourly marginal energy price the following charges will also apply:

0.733¢/kWh for MISO network transmission costs and MISO energy market costs plus,
An administrative charge of 1.619¢/kWh plus,
Surcharges and Credits Applicable to Power Supply, excluding PSCR, as approved by the Commission. See Section C8.5

Service Charge:

Primary Service Charge: $275 per month
Subtransmission and Transmission Service Charge: $375 per month

LATE PAYMENT CHARGE: See Section C4.8

CONTRACT TERM: The contract term is from month to month until terminated by mutual consent or on one month written notice by either party.
D4. LARGE COMMERCIAL & INDUSTRIAL SERVICE  
Cp-1M  

**EFFECTIVE IN:** All territory served.  

**AVAILABILITY**  
This schedule is applicable to customers whose monthly demand is equal to or greater than 100 kW or 25,000 kWh/month for three consecutive months and others taking standby service. This schedule is also available to small commercial and industrial customers who contract for service under the Cp-12M Interruptible Rider. This service is not available for customers required to take service under the Power Supply Default Service. Customers taking service under the Retail Access Service Tariff (RAST) shall be responsible for the Distribution Charges but not the Power Supply Charges under this rate schedule. Customers that purchase power supply service from the Company shall be subject to both the Distribution and Power Supply charges contained in this rate schedule.  

The transmission rates are available to customers that take service directly from a company-owned substation (i.e. Company owns no distribution facilities downstream of substation). For customers that meet this condition, a monthly charge of $0.49/kVA of installed substation transformer capacity as determined by the company shall apply.

**MONTHLY RATE**  

<table>
<thead>
<tr>
<th>Distribution Service</th>
<th>Secondary</th>
<th>Primary</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fixed Charge:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monthly</td>
<td>$142.00</td>
<td>$673.00</td>
<td>$990.00</td>
</tr>
<tr>
<td>Daily</td>
<td>$4.6685</td>
<td>$22.1260</td>
<td>$32.5479</td>
</tr>
<tr>
<td><strong>Demand Charge</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Customer Demand:$/kW</td>
<td>$2.95</td>
<td>$2.22</td>
<td>$0.00</td>
</tr>
<tr>
<td>Per KW of maximum demand during the current and preceding 11 months, plus,</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. On-Peak Demand</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10:00 AM to 8:00 PM; Monday through Friday (except holidays)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b. <strong>Summer (Jun-Sep):$/kW</strong></td>
<td>$1.14</td>
<td>$1.14</td>
<td>$1.14</td>
</tr>
<tr>
<td>10:00 AM to 11:00 PM; Monday through Friday (except holidays)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Power Supply Service (Optional)**  

<table>
<thead>
<tr>
<th>On-Peak Demand</th>
<th>Secondary</th>
<th>Primary</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>10:00 AM to 8:00 PM; Monday through Friday (except holidays)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b. <strong>Summer (Jun-Sep):$/kW</strong></td>
<td>$12.90</td>
<td>$12.61</td>
<td>$12.44</td>
</tr>
<tr>
<td>10:00 AM to 11:00 PM; Monday through Friday (except holidays)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Energy Charge**  

<table>
<thead>
<tr>
<th>On-Peak</th>
<th>Secondary</th>
<th>Primary</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. <strong>Winter (Oct-May):$/kWh</strong></td>
<td>$0.06197</td>
<td>$0.06017</td>
<td>$0.05942</td>
</tr>
<tr>
<td>6:00 AM to 10:00 PM; Monday through Friday (except holidays)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b. <strong>Summer (Jun-Sep):$/kWh</strong></td>
<td>$0.06197</td>
<td>$0.06017</td>
<td>$0.05942</td>
</tr>
<tr>
<td>7:00 AM to 11:00 PM; Monday through Friday (except holidays)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Off-Peak</td>
<td>Secondary</td>
<td>Primary</td>
<td>Transmission</td>
</tr>
<tr>
<td>a. <strong>Winter (Oct-May):$/kWh</strong></td>
<td>$0.03350</td>
<td>$0.03253</td>
<td>$0.03212</td>
</tr>
<tr>
<td>10:00 PM to 6:00 AM; Monday through Friday, all day Saturday, Sunday, and holidays</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b. <strong>Summer (Jun-Sep):$/kWh</strong></td>
<td>$0.03350</td>
<td>$0.03253</td>
<td>$0.03212</td>
</tr>
<tr>
<td>11:00 PM to 7:00 AM; Monday through Friday, all day Saturday, Sunday, and holidays</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: For a 10:00 PM change between on peak and off peak time periods in the Winter months, on peak consumption will be recorded through 10:00 PM. Off Peak consumption will begin at 10:00:01 PM as recorded by the meter.
M.P.S.C. No. 1 – Electric
Upper Michigan Energy Resources Corporation

D4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Cp-1M)

MINIMUM CHARGE
The monthly minimum charge is the fixed charge, the demand charges, and the energy optimization charge.

POWER SUPPLY COST RECOVERY CLAUSE:
See Schedule PSCR.

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
See Schedule EO starting on Sheet D-156.00
The above listed voltages are phase-to-ground for wye-connected company systems and phase-to-phase for delta-connected company systems.

STANDBY SERVICE
Where service is made available to loads which can be served by a source of power other than the company's (excluding emergency standby maintained in the event of failure of company's supply), billing shall be at the above rate, but the monthly minimum demand charge (total of customer charge, on-peak demand charge, and substation transformer capacity charge) for standby service shall be not less than the following per kW of contracted demand:

\[
\begin{align*}
\text{Cp Secondary:} & \quad $3.50 \\
\text{Cp Primary:} & \quad $2.75 \\
\text{Cp Transmission:} & \quad $2.00 
\end{align*}
\]

This standby service clause assumes that standby customers shall schedule normal maintenance of the customer-owned source of power during periods of the year that are satisfactory to the company. Accordingly, customers shall advise the company of planned maintenance with as much advance notice as possible. These waivers are granted on a conditional basis. The company will rescind the waiver of increased demand during times of emergency interruptions. The company shall confirm in writing the maintenance schedule that is satisfactory to both parties.

The portion of the on-peak demand shall be billed on a prorated basis on a $/kW/day basis as shown below.

**Pro-ration Formula - Firm Load:**
\[
\frac{\text{On-Peak Demand Charge} \times 12 \text{ months}}{\text{No. of annual peak days}} \times \frac{\text{No. of waiver days}}{12}
\]

**Pro-ration Formula - Interruptible Load:**
\[
\frac{\text{Variable Interruptible Demand Charge} \times 12 \text{ months}}{\text{No. of annual peak days}} \times \frac{\text{No. of waiver days}}{12}
\]

These billing benefits shall only apply to the unusual portion of the customer's monthly demand. All demands except that portion of the peak load demand resulting from a company-approved maintenance schedule shall be billed as standard normal demand in accordance with all other sections of this rate schedule. The above clause shall not apply to customer-owned generation served under the Standby Service clause of this rate schedule and/or Maintenance Rate of the Pg-2 rate schedule because customers served under these clauses have similar provisions within their clauses. If the highest demand in any month exceeds the contract demand, the minimum demand charge shall thereafter be based on the highest actual demand. The company may install suitable devices to limit the actual demand to the contract demand and may limit size of standby load to be served under this rate to the available system capacity at the customer's location.

(Continued on Sheet No. D-121.00)
D4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued on Sheet No. D-120.00) Cp-1M

REACTIVE LOAD
The customer shall keep his lagging reactive load at a level that does not exceed his Kw demand and shall not operate with a leading reactive load.

SHORT TERM SERVICE
Short term and temporary service is available to customers requiring service for less than annual periods.
1. a) For holiday/decorative lighting see Schedule Ls-1M,
   b) For special events see Schedule RIIIM, Temporary Service
   c) For construction see Schedule RIIIM, Temporary Service
2. Standard proration rules shall apply to the initial and final billing periods.
3. At the expiration of any month, the customer may cancel his contract for service under these provisions and may contract for one year or more under the standard rate applicable to his service.

VARIATION OF DEMAND
Variation of customer load shall be limited to time changing demand levels which are within system standards of operation as established by the company. Failure to take service in a manner which meets these standards may result in discontinuation of service.

TERM OF CONTRACT
Minimum period of one year except that for new or additional loads of 5,000kW or more, a term of not less than five years will be required.

DETERMINATION OF DEMAND
The customer demand in kilowatts shall be the highest single 15 minute integrated load observed or recorded during the current or preceding 11 months. For new Cp-1M customers, this demand provision applies on and after the date of transfer to this rate schedule.

The on-peak billing demand in kilowatts shall be the highest single 15 minute integrated load observed or recorded during each respective time period in the month, provided that no billing demand shall be less than 60% of the highest billing demand of the preceding 11 months.

Unusual on-peak billing demands approved by advance authority from the company shall be billed but will not be considered in the determination of the 60% ratchet. Customer requests for unusual demands shall be made in advance with as much allowance as possible. The advance authorization from the company shall be confirmed in writing.

HOLIDAYS
The days of the year which are considered holidays are: New Year's Day, Good Friday, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, Friday After Thanksgiving, Day Before Christmas, Christmas Day, Day Before New Year's Day.

ESTIMATION PROCEDURE
In the event of loss of data for calculation of one or more billing parameters, the company shall forecast on the basis of historic billing parameters to obtain an estimate of current month's billing parameters. This estimate shall be subject to modification or replacement based on known and quantifiable operating conditions of the current month.
## D2. Large Commercial & Industrial Service

### WHO MAY TAKE SERVICE:
This schedule is applicable to customers whose monthly demand is equal to or greater than 200 kW for three consecutive months and at least once in each succeeding 12 month period and others taking standby service. This service is not available for customers required to take service under the Power Supply Default Service. Customers taking service under the Retail Access Service Tariff (RAST) shall be responsible for the Distribution Charges but not the Power Supply Charges under this rate schedule. Customers that purchase power supply service from the Company shall be subject to both the Distribution and Power Supply charges contained in this rate schedule.

Customers that take service directly from the company-owned substation (i.e. Company owns no distribution facilities downstream of substation) will be classified as Transmission and receive the Substation Transformer Capacity charge.

### MONTHLY RATE

<table>
<thead>
<tr>
<th>DISTRIBUTION SERVICE</th>
<th>Secondary</th>
<th>Primary</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Customer Charge:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monthly</td>
<td>$250.00</td>
<td>$325.00</td>
<td>$750.00</td>
</tr>
<tr>
<td>Daily</td>
<td>$8.2192</td>
<td>$10.6849</td>
<td>$24.6575</td>
</tr>
<tr>
<td><strong>Demand Charge</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Customer Demand:$/KW</td>
<td>$2.60</td>
<td>$1.95</td>
<td>$0.00</td>
</tr>
<tr>
<td>Per KW of maximum demand during the current and preceding 11 months, plus,</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. On-Peak</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Firm Demand:$/KW</td>
<td>$2.14</td>
<td>$2.06</td>
<td>$1.99</td>
</tr>
<tr>
<td>Interruptible Demand:$/KW</td>
<td>$2.14</td>
<td>$2.06</td>
<td>$1.99</td>
</tr>
<tr>
<td>7:00 AM to 11:00 PM; Monday through Friday (except holidays).</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Substation Transformer Capacity:</strong>$/kVA</td>
<td></td>
<td></td>
<td>$0.75</td>
</tr>
</tbody>
</table>

Continued to Sheet No. D-25.20

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Issued: 9-23-16
By S C Devon
Director - Regulatory Affairs
Marquette, Michigan

Effective for Service
On and After: 9-23-16
Issued Under Auth. of Mich Public Serv Comm
Dated: 9-8-16
In Case No: U-17895
D2. Large Commercial & Industrial Service  

Continued from Sheet No. D-25.10

<table>
<thead>
<tr>
<th>POWER SUPPLY SERVICE (Optional)</th>
<th>Secondary</th>
<th>Primary</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-Peak</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Firm Demand: $/kW</td>
<td>$11.05</td>
<td>$10.66</td>
<td>$10.26</td>
</tr>
<tr>
<td>Interruptible Demand: $/kW</td>
<td>$3.55</td>
<td>$3.16</td>
<td>$2.76</td>
</tr>
</tbody>
</table>

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

Energy Charge

1. On-Peak

| Energy Charge:$/kWh             | $0.09003  | $0.08678 | $0.08360     |
|                                | 7:00 AM to 11:00 PM; Monday through Friday (except holidays). |

2. Off-Peak

| 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. Large Commercial & Industrial Service Rules**

Continued from Sheet No. D-25.20

The above listed voltages are phase-to-ground for wye-connected company systems and phase-to-phase for delta-connected company systems.

**STANDBY SERVICE**

Where service is made available to loads which can be served by a source of power other than the company's (excluding emergency standby maintained in the event of failure of company's supply), billing shall be at the above rate, but the monthly minimum demand charge (total of customer demand charge, on-peak demand charge, and substation transformer capacity charge) for standby service shall be not less than the following per KW of contracted demand:

<table>
<thead>
<tr>
<th>Type</th>
<th>Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cp-U Secondary</td>
<td>$3.50</td>
</tr>
<tr>
<td>Cp-U Primary</td>
<td>$2.75</td>
</tr>
<tr>
<td>Cp-U Transmission</td>
<td>$2.00</td>
</tr>
</tbody>
</table>

This standby service clause assumes that standby customers shall schedule normal maintenance of the customer-owned source of power during periods of the year that are satisfactory to the company. Accordingly, customers shall advise the company of planned maintenance with as much advance notice as possible. These waivers are granted on a conditional basis. The company will rescind the waiver of increased demand during times of emergency interruptions. The company shall confirm in writing the maintenance schedule that is satisfactory to both parties.

The portion of the on-peak demand shall be billed on a prorated basis on a $/KW/day basis as shown below.

**Pro-ration Formula - Firm Load:**

\[
\text{On Peak Demand Charge} \times \frac{\text{Number of Approved Nonholiday Weekdays in Billing Cycle}}{\text{Number of Nonholiday Weekdays in Billing Cycle}}
\]

**Pro-ration Formula - Interruptible Load:**

\[
\text{Variable Interruptible Demand Charge} \times \frac{\text{Number of Approved Nonholiday Weekdays in Billing Cycle}}{\text{Number of Nonholiday Weekdays in Billing Cycle}}
\]

These billing benefits shall only apply to the unusual portion of the customer’s monthly demand. All demands except that portion of the peak load demand resulting from a company-approved maintenance schedule shall be billed as standard normal demand in accordance with all other sections of this rate schedule. The above clause shall not apply to customer-owned generation served under the Standby Service clause of this rate schedule and/or Maintenance Rate of any net metering or parallel generation rate schedule because customers served under these clauses have similar provisions within their clauses.

If the highest demand in any month exceeds the contract demand, the minimum demand charge shall thereafter be based on the highest actual demand. The company may install suitable devices to limit the actual demand to the contract demand and may limit size of standby load to be served under this rate to the available system capacity at the customer's location.

Continued to Sheet No. D-25.40
### D4. Large Commercial & Industrial Service Rules

<table>
<thead>
<tr>
<th>Cp-U</th>
</tr>
</thead>
</table>

Continued from Sheet No. D-25.30

**REACTIVE LOAD**

The customer shall keep his lagging reactive load at a level that does not exceed his Kw demand and shall not operate with a leading reactive load.

**SHORT TERM SERVICE**

Short term and temporary service is available to customers requiring service for less than annual periods.

1. a) For holiday/decorative lighting see Schedule SL-X, b) For special events or construction see Sheet No. C-19.00, Section III - Line Extension Construction Policy Temporary Service.

2. Standard proration rules shall apply to the initial and final billing periods.

3. At the expiration of any month, the customer may cancel his contract for service under these provisions and may contract for one year or more under the standard rate applicable to his service.

**VARIATION OF DEMAND**

Variation of customer load shall be limited to time changing demand levels which are within system standards of operation as established by the company. Failure to take service in a manner which meets these standards may result in discontinuation of service.

Continued to Sheet No. D-25.50
D4. Large Commercial & Industrial Service Rules Cp-U

Continued from Sheet No. D-25.40

DETERMINATION OF DEMAND

The customer demand in kilowatts shall be the highest single 15 minute
integrated load observed or recorded during the current or preceding 11 months.
For new Cp-U customers, this demand provision applies on and after the date of
transfer to this rate schedule.

The on-peak billing demand in kilowatts shall be the highest single 15 minute
integrated load observed or recorded during each respective time period in the
month, provided that no billing demand shall be less than 60% of the highest
billing demand of the preceding 11 months and, in no case, less than 200 Kw.

Unusual on-peak billing demands approved by advance authority from the company
shall be billed but will not be considered in the determination of the 60%
ratchet. Customer requests for unusual demands shall be made in advance with as
much allowance as possible. The advance authorization from the company shall be
confirmed in writing.

HOLIDAYS

The days of the year which are considered holidays are: New Year's Day,

ESTIMATION PROCEDURE

In the event of loss of data for calculation of one or more billing parameters,
the company shall forecast on the basis of historic billing parameters to obtain
an estimate of current month's billing parameters. This estimate shall be
subject to modification or replacement based on known and quantifiable operating
conditions of the current month.

Issued: 12-21-09
By J F Schott
VP Regulatory Affairs
Green Bay, Wisconsin

Michigan Public Service Commission
December 29, 2009
Filed

Effective for Service
On and After: 1-1-10
Issued Under Auth. of
Mich Public Serv Comm
Dated: 12-16-09
In Case No: U-15988
# Conceptual Model Standby Rate Tariff (DRAFT 10/14/16)

<table>
<thead>
<tr>
<th>Monthly Customer Charge</th>
<th>Monthly Reservation Fee</th>
<th>On-Peak Daily, Daily or Hourly Demand Charge</th>
</tr>
</thead>
</table>
| ● Zero, assuming this is already included in the customer’s supplemental power tariff (Based on administrative costs)  
  AND  
  ● Charge or Credit to reflect greater or lesser administrative costs associated with partial use customer. | ● Zero (instead recover in demand charge)  
  OR  
  ● Fixed fee to recover utility’s embedded costs for generation capacity (or capacity market purchases) and transmission based on FOR of best performing CHP systems | ● Zero  
  OR  
  ● Low variable demand charge proportionate to hours of planned usage reflecting utility’s lower costs due to planning at times that impose zero or low cost to utility.  
  AND  
  ● Reduced (or zero) variable demand charge for off-peak usage to reflect utility’s lower costs during off-peak hours. |
|  |  | Scheduled  
  Unscheduled  
  ● If no Reservation Fee, variable demand charge designed to recover proportion of utility’s embedded costs for generation capacity (or capacity market purchases) and transmission based on CHP partial-use customer’s hours of unscheduled use.  
  OR  
  ● If a fixed Reservation Fee is also charged, variable demand charge designed to recover utility’s embedded costs for |
generation capacity (or capacity market purchases) and transmission based on CHP partial use customer’s proportionate use above FOR assumed in Reservation Fee

AND

● Reduced (or zero) variable demand charge for off-peak usage to reflect utility’s lower costs during off-peak hours.

<table>
<thead>
<tr>
<th>Energy Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>● If no Reservation Fee and Demand Charge, recover proportion of utility’s embedded costs for generation capacity (or capacity market purchases) and transmission in energy charges based on CHP partial-use customer’s hours of use.</td>
</tr>
<tr>
<td>● Pricing should reflect utility’s lower costs for scheduled usage and off-peak usage.</td>
</tr>
<tr>
<td>OR</td>
</tr>
<tr>
<td>● If embedded generation capacity (or capacity market purchases) and transmission are recovered in Reservation Fee and/or Demand Charge, energy pricing should reflect utility’s average fuel and purchased energy costs (or utility’s spot energy market purchases in the case of capacity market purchases).</td>
</tr>
<tr>
<td>AND</td>
</tr>
<tr>
<td>● Pricing should reflect peak and off-peak energy prices or real time energy prices.</td>
</tr>
</tbody>
</table>

Notes:

1. On-Peak Daily, Daily and Hourly demand billing units should be calculated as the customer’s demand in excess of its supplemental service demand billing units. For example, assume a customer has a 50 MW generator and 50 MW of supplemental demand. If the customer in a given hour has a 25 MW generation derate, but its supplemental demand is simultaneously down by 25 MW such that the customer’s net demand is still below 50 MW, the standby demand for that customer for that hour should be zero.

2. Delivery (i.e., distribution) service charges for standby service should generally be the same for standby service as they are for supplemental service (including any credits for a customer ownership of their own substation). However, where there are distribution networks whose costs are driven by the peak demand on that network rather than the non-coincident peak demand of individual customers, consideration should be given to the expected contribution of the standby service to the peak demand placed on that distribution network.
Appendix C: Standby Service Rate Comparison

### Scenario 1: No Generator Outage

<table>
<thead>
<tr>
<th></th>
<th>Consumers</th>
<th>DTE</th>
<th>UMERC</th>
<th>UPPCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Charge</td>
<td>200</td>
<td>275</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Delivery Capacity/Distribution Charge</td>
<td>8,100</td>
<td>6,760</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Reservation Fee</td>
<td>0</td>
<td>3,500</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Demand Charges</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Energy Charges</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>8,300</td>
<td>10,535</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

### Scenario 2: Scheduled Generator Outage 16 hours off-peak

<table>
<thead>
<tr>
<th></th>
<th>Consumers</th>
<th>DTE</th>
<th>UMERC</th>
<th>UPPCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Charge</td>
<td>200</td>
<td>275</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Delivery Capacity/Distribution Charge</td>
<td>8,100</td>
<td>6,760</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Reservation Fee</td>
<td>0</td>
<td>3,500</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Demand Charges</td>
<td>0</td>
<td>0</td>
<td>1,182</td>
<td>1,106</td>
</tr>
<tr>
<td><strong>Energy Charges</strong></td>
<td>946</td>
<td>1,122</td>
<td>1,036</td>
<td>1,805</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>9,246</td>
<td>11,657</td>
<td>2,218</td>
<td>2,911</td>
</tr>
</tbody>
</table>

### Scenario 3: Scheduled Generator Outage 16 hours on-peak

<table>
<thead>
<tr>
<th></th>
<th>Consumers</th>
<th>DTE</th>
<th>UMERC</th>
<th>UPPCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Charge</td>
<td>200</td>
<td>275</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Delivery Capacity/Distribution Charge</td>
<td>8,100</td>
<td>6,760</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Reservation Fee</td>
<td>0</td>
<td>0</td>
<td>1,182</td>
<td>1,106</td>
</tr>
<tr>
<td>Demand Charges</td>
<td>2,232</td>
<td>10,400</td>
<td>1,916</td>
<td>2,777</td>
</tr>
<tr>
<td><strong>Energy Charges</strong></td>
<td>1,113</td>
<td>1,218</td>
<td>1,916</td>
<td>2,777</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>11,645</td>
<td>18,653</td>
<td>3,098</td>
<td>3,883</td>
</tr>
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</table>

### Scenario 4: Scheduled Generator Outage 8 hours on-peak, 8 hours off-peak

<table>
<thead>
<tr>
<th></th>
<th>Consumers</th>
<th>DTE</th>
<th>UMERC</th>
<th>UPPCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Charge</td>
<td>200</td>
<td>275</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Delivery Capacity/Distribution Charge</td>
<td>8,100</td>
<td>6,760</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Reservation Fee</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Demand Charges</td>
<td>1,116</td>
<td>5,200</td>
<td>1,182</td>
<td>1,106</td>
</tr>
<tr>
<td><strong>Energy Charges</strong></td>
<td>1,775</td>
<td>1,170</td>
<td>1,476</td>
<td>2,291</td>
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<td><strong>TOTAL</strong></td>
<td>11,191</td>
<td>13,405</td>
<td>2,658</td>
<td>3,397</td>
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</table>

21 Energy charges calculations for Consumers provided by Consumers.
### Scenario 5: Scheduled Generator Outage 32 hours on-peak

<table>
<thead>
<tr>
<th></th>
<th>Consumers</th>
<th>DTE</th>
<th>UMERC</th>
<th>UPPCO</th>
</tr>
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<tbody>
<tr>
<td>Service Charge</td>
<td>200</td>
<td>275</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Delivery Capacity/Distribution Charge</td>
<td>8,100</td>
<td>6,760</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Reservation Fee</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Demand Charges</td>
<td>4,463</td>
<td>20,800</td>
<td>2,364</td>
<td>2,212</td>
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<tr>
<td>Energy Charges</td>
<td>2,070</td>
<td>2,436</td>
<td>3,832</td>
<td>5,554</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>14,833</td>
<td>30,272</td>
<td>6,196</td>
<td>7,766</td>
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</table>

### Scenario 6: Unscheduled Outage 8 hours on-peak, 8 hours off-peak

<table>
<thead>
<tr>
<th></th>
<th>Consumers</th>
<th>DTE</th>
<th>UMERC</th>
<th>UPPCO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Charge</td>
<td>200</td>
<td>275</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Delivery Capacity/Distribution Charge</td>
<td>8,100</td>
<td>6,760</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Reservation Fee</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Demand Charges</td>
<td>1,116</td>
<td>9,340</td>
<td>29,060</td>
<td>29,340</td>
</tr>
<tr>
<td>Energy Charges</td>
<td>1,775</td>
<td>1,170</td>
<td>1,476</td>
<td>2,291</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>11,191</td>
<td>17,545</td>
<td>30,536</td>
<td>31,631</td>
</tr>
</tbody>
</table>
Appendix D-Comments
June 2, 2017

Julie Baldwin
Manager
Renewable Energy Section
Electric Reliability Division
Michigan Public Service Commission

Re: Michigan Public Service Commission Standby Rate Working Group

Dear Ms. Baldwin:

On behalf of the Association of Businesses Advocating Tariff Equity (“ABATE”), we wish to thank the Michigan Public Service Commission Staff (“Staff”) for providing an opportunity for stakeholders to provide comments on its May 2017 draft Standby Working Group Supplemental Report (“Draft Supplemental Report”).

In general, ABATE believes the Staff has done a good job in summarizing the views expressed by stakeholders during the discussions of the Standby Working Group and in the comments submitted by stakeholders. However, ABATE believes the report would benefit from additional detail being provided on certain issues raised by ABATE that were captured in summary form in the Draft Supplemental Report. To this end, we have attached to these comments our comments from March 17, 2017, and ask that they be included in the appendix of the final version of the Staff’s Standby Rate Working Group Supplemental Report.
With one modification, ABATE supports the seven recommendations that the Staff has included in the Draft Supplemental Report. In particular, ABATE is very pleased with Recommendation No. 3, which calls for standby capacity and delivery demand charges to be based on net load for customers taking both supplemental and standby service. Implementing this recommendation will help eliminate the possibility of over-recovery of capacity and delivery service costs from these customers.

The one modification ABATE proposes to the recommendations is with respect to Recommendation No. 1. Specifically, Recommendation No.1 calls for improving standby service tariff transparency by having the utilities work with Staff. ABATE believes that utilities should be required to work with stakeholders as well as Staff. This would ensure input is being provided by those who utilize, or would utilize, the standby service tariffs, in addition to Staff. To address this, ABATE proposes that Staff modify Recommendation No.1 as follows:

1. To assist with standby service tariff transparency, a clear and concise description of the tariff structure and each term used should be included. Utilities should work with staff and stakeholders to ensure a good understanding of 1) the standby service tariff; 2) information available on the company’s website; and 3) the company’s preferred process for developers and customers to get standby service questions answered.

As a final note, while ABATE believes the Draft Supplemental Report provides a good review of the standby service tariffs of Michigan’s largest utilities to ensure equitable revenue allocation and rates that are correlated to cost of service, transparent, and designed to send a clear price signal for the most efficient interface between utility and customer resources, we note that the Draft Supplemental Report does not directly achieve these results. The Draft Supplemental Report leaves many outstanding issues for resolution in the current and forthcoming general rate proceedings of the utilities. As a result, the work will not be complete until those issues are reasonably resolved in those proceedings. It is very important for that work to be completed in order to ensure customer generation is not an underutilized resource in Michigan.

ABATE appreciates the opportunity it had to both provide these comments and to participate in the Standby Rate Working Group. We look forward to the opportunity to participate in the current and forthcoming general rate proceedings of the utilities in order to ensure the standby service tariffs of Michigan’s utilities provide equitable revenue allocation and rates that are correlated to cost of service, transparent, and designed to send a clear price signal for the most efficient interface between utility and customer resources. If you have any questions regarding our comments, please do not hesitate to reach out to our consultant, Jim Dauphinais at either (636) 898-6725 or jdauphinais@consultbai.com.
Thank you.

Rod Williamson
Executive Director of ABATE

Attachment: March 17, 2017 Comments of ABATE re: Standby Rate Working Group

cc: Jim Dauphinais
    Sean Gallagher
Attachment to June 2, 2017 ABATE Comments

MPSC Standby Rate Working Group:
March 17, 2017 ABATE Comments
March 17, 2017

Julie Baldwin
Manager
Renewable Energy Section
Electric Reliability Division
Michigan Public Service Commission

Re: Michigan Public Service Commission Standby Rate Working Group

Dear Ms. Baldwin:

We wish to thank the Michigan Public Service Commission Staff (“Staff”) for providing an opportunity for stakeholders to provide comments prior to Staff drafting its Standby Rate Working Group report. Today, in concert with many other global manufacturers with operations, employees and customers in Michigan, the Association of Businesses Advocating Tariff Equity (“ABATE”), on behalf of its members, has participated in a joint letter to Chairman Talberg emphasizing the need to ensure standby service rates in Michigan are fair and reasonable. As stated in the letter to Chairman Talberg, it is important that the standby service tariffs of Michigan’s utilities be reviewed to ensure equitable revenue allocation and rates that are correlated to cost of service. In addition, these rates should be transparent and designed to send a clear price signal for the most efficient interface between utility and customers resources.

To this end, we today offer the following additional comments with respect to accomplishing the outcome outlined above. These comments may be publicly shared and we ask that the Staff post them on the webpage for the Standby Rate Working Group.
Separate Rate Class

Standby service customers should be placed in their own separate rate class recognizing the very low load and coincidence factors of these customers as a whole. For example, data provided by Consumers Energy Company and DTE Electric Company indicated that, as a whole, existing standby service customers have load and coincidence factors in the neighborhood of 20% -- much lower than for any other group of customers.

In addition, to the extent the utility's own generation is providing this service and there is sufficient normalized data available, revenue should be allocated to this class of customers consistent with a reasonably performed class cost of service study. If there is not sufficient normalized data available, reasonable proxy data may need to be utilized for the class. This may in particular be necessary when a standby service rate is first being introduced (since there would be no existing standby service customers) or when it is expected there will be a large expansion of the use of the rate and that expansion is expected to change the characteristics of the class as a whole. In the case where a utility is providing standby service from the wholesale market, the basis of the revenue requirement for the rate should be based on the cost of the utility to purchase capacity in the market.

Reservation Charges

Reservation charges are monthly demand charges for generation capacity and transmission (“Power Supply”) usually applied to a customer’s contracted standby service demand (“Reservation Charges”). In general, we do not support the use of Reservation Charges and instead support recovery of the Power Supply costs through daily, or daily on-peak, demand charges applied to a customer’s actual daily, or daily on-peak, standby service demand. This sends an important price signal for the customer to minimize its draw of standby service demand. This said, if a Reservation Charge is used for Power Supply, it should be based on no more than the equivalent of a single day’s daily, or daily on-peak, demand charge for the rate and daily, or daily on-peak, demand charges should be waived for the first day of outage for a customers during a given month. Reservation Charges based on multiple days of outages should be avoided. For example, one of the Michigan utilities currently has a Reservation Charge which collects revenues equal to that of approximately 12% of the full service monthly demand charge of that same utility. Essentially, the utility is requiring its standby service customers to pay for a minimum of 2.4 on-peak days of standby service even if the customer does not draw any standby service in that month. This eliminates any price signal there might be for the customer to minimize its use of standby service below 2 days of on-peak standby service. It also requires members of the standby service class with better performance to subsidize those with poorer performance. Again, we believe it is best not to use a Reservation Charge at all, but if one is used, it should be based on no more than one day’s, or one on-peak days, worth of daily, or on-peak daily, demand charges.

Daily, or On-Peak Daily, Standby Service Demand Charges

As we have noted, we believe Power Supply costs for the provision of standby service are best recovered through the use of daily, or on-peak daily, demand charges. To be consistent with the principles of FERC PURPA rules for standby service (18 CFR Ch. I, § 292.305 (c)) and the principles of good rate design, these demand charges need to be designed in such a fashion as they do not assume that forced outages or other reductions in electric output by all customer generation on an electric utility's system will occur simultaneously, or during the system peak, or both. In addition, the standby
service demand charges should take into account the extent to which scheduled outages of customer generation can be usefully coordinated with scheduled outages of the utility's facilities. To this end, we believe the best practice is to use a flat prorated daily, or on-peak daily, demand charge for unscheduled outages and a daily, or daily on-peak, demand charge of no greater than 50% of this amount for scheduled outages that have been coordinated with the customer’s utility. This rate design applies charges to customers in proportion to their likelihood of drawing standby service for an unscheduled outage at the time of the system peak and sends a price signal to customers to minimize their draw of standby service regardless of the amount of standby service they have already drawn in a given month. It also assures standby service customers with better performing generation are not subsiding standby service customers with poorer performing generation.

If a utility’s Power Supply revenue requirement has been reasonably allocated to the standby service class, the daily or on-peak daily demand charge for unscheduled outages should be very close to 3.3% and 5%, respectively, of the monthly Power Supply demand charge for the full service rate the customers would have used if it did not have its own generation. In the case of a utility using the wholesale market to provide standby service, the daily or on-peak daily demand charge for unscheduled outages should be set at 3.3% or 5%, respectively, of the utility’s market cost for capacity and transmission. In both cases, the daily or daily on-peak demand charge for scheduled outages coordinated with the customers’ utility should no more than 50% of the daily or daily on-peak demand charge for unscheduled outages as the coordination of these outages with the customer’s utility should ensure they have little to no effect on a utility’s total need for generation capacity and transmission facilities.

Another important consideration for standby service is the basis of daily, or on-peak daily, demand. In many cases, a customer is taking both standby service under a standby service tariff and supplemental service under a full service tariff. In these situations, it is important that the interaction between the two rates not lead to the over-recovery of costs by the utility. One major way in which over-recovery can occur is with respect to the determination of a customer’s daily, or on-peak daily, demand. Specifically, it is important that when a customer’s daily, or on-peak daily, demand is determined that it account for the amount of supplemental service the customer is taking at the time. For example, if the monthly supplemental service demand of the customer is 20,000 kW and the customer’s total demand at the time of an outage of its 5,000 kW generator is only 20,000 kW, the customer’s

---

1 A daily demand charge should be designed to collect revenue in proportion to the number of days of standby service is actually taken. Thus, if standby service is taken for all the days of the month, there should be little difference between the full service demand charge and the total demand charges collected for standby service from that customer for that month. However, if standby service is taken by a customer for only a single day of that month, the demand charge should be proportionally reduced to 1/30th or 3.3% of the full service monthly demand charge reflecting that there are typically 30 days in a month. This can be accomplished by using a daily demand charge that is approximately equal to 3.3% of the full service monthly demand charge. Such a demand charge provides a price signal to the customer to minimize the amount of standby service taken over the course of a given month regardless of the amount standby service the customer has already taken during that same month. When daily on-peak demand charges are used, the same effect can be accomplished by using a daily on-peak demand charge equal to approximately 1/20th or 5% of the full service monthly demand charge consistent with there be typically being 20 on-peak days in a month.
daily, or on-peak daily standby service demand, should be zero, not 5,000 kW. The reason for this is that the customer is already paying supplemental service monthly power supply charge to the utility for 20,000 kW of demand. The outage of the customer’s generation did not create any additional need for capacity for the utility, since the customer’s supplemental demand during the time of the generation outage was down from its monthly peak value by an amount more than sufficient to cover for the outage of the customer’s generation. If the utility were permitted to assess a daily, or on-peak daily, standby service demand charge of 5,000 kW for this generation outage, the utility would recover the cost for that 5,000 kW of power supply twice – once through the supplemental service rate monthly demand charges and again through the standby service rate.

Delivery Service Demand

It is also important to avoid a possibility of over-recovery of delivery service charges when a customer is taking both standby service and supplemental service. For the supplemental service, the customer will be paying a delivery service demand charge for the highest supplemental service demand during the month. To this end, delivery service demand charges should only be assessed on the basis of the largest net demand the customer places on the system. This can be accomplished if daily, or daily on-peak, standby delivery service demand is determined in the manner outlined above.

Customer Charges

Another area of potential over-recovery is with respect to customer charges. A customer taking both standby service and supplemental service should not be required to pay the same customer charge twice. It should only pay a customer charge for supplemental service. If there is a customer charge for standby service, it should only recover the true incremental customer-related costs that the utility to incurs provide standbys service to the customer in addition to supplemental service, to avoid over-recovery.

Existing Consumers Energy Company and DTE Electric Company Standby Service Rates

Consumers Energy Company’s (“Consumers”) current Rate GSG-2 standby service rate is generally consistent with many of the principles discussed above in that it does not included Reservation Charges and uses daily on-peak demand charges that are based on an on-peak day proration of Consumers’ highest monthly market cost of capacity. However, it is still not clear at this time whether Consumers calculates a customer’s standby service demand in consideration of the amount supplemental service the customer is also taking. As we have discussed above, when a customer’s generation is having an outage or has otherwise had a reduction in output, its daily on-peak standby service demand should only be equal to the amount of its total demand that is in excess of its monthly supplemental service demand. In addition, Consumers’ current standby service rate does not include provisions for lower daily on-peak demand charges for scheduled customer generation outages that are coordinated with Consumers. As noted above, daily on-peak demand charges for schedules outages should be set at 50% or less of the daily on-peak demand charge for unscheduled outages because the coordination of these outages with Consumers should ensure they have little to no effect on a utility’s total need for generation capacity and transmission facilities.
Unlike with Consumers, DTE Electric Company’s (“DTE”) current Rider 3 standbys service rate is generally inconsistent with many of the rate design principles discussed above. It includes a Reservation Charge which is currently set at approximately 12% of the full-service rate’s Power Supply monthly demand charge. As discussed, a properly designed standby rate should not have such a charge at all, or it should at least be limited to the equivalent of one on-peak day per month (i.e., 5% instead of 12%). In light of the principles discussed above, we find it more troubling that the current daily on-peak standby demand charge for Rider 3 is set at approximately 31.9% of the full-service rate’s Power Supply demand charge. This is level of charge is extreme when compared with the 5% that would result from an on-peak day proration of the full-service rate’s monthly demand charge. During the Standby Rate Working Group discussion, it became apparent that the underlying cause of the problems with DTE’s Rider 3 may be related to a very dated allocation of DTE’s revenue requirement to Rider 3 customers. In particular, rather than treating standby service customers as a separate rate class in its class cost of service studies, DTE was assigning a percentage of the revenue requirement assigned to Rate D11 to Rider 3 based on assumptions that are many years old. We are hopeful that modeling Rider 3 customers as a separate rate class in future class cost of service studies will largely address the forgoing issues. However, other adjustments may also ultimately be needed with respect to the design of the Reservation Charge and daily on-peak demand charges for Rider 3 in order to make them reasonable.

DTE’s Rider 3 does consider monthly supplemental service demand when determining a customer’s daily on-peak standby service demand. In addition, Rider 3 also includes lower daily on-peak demand charges for maintenance outages. However, neither of these provisions mitigates the serious problem that currently exists with the magnitude of the Rider 3 Reservation Charge and daily on-peak demand charges.

ABATE appreciates the opportunity it had to both provide these pre-report comments and to participate in the Standby Rate Working Group. We look forward to the opportunity to provide comments on the Staff’s draft report upon its release. If you have any questions regarding our comments, please do not hesitate to reach out to our consultant, Jim Dauphinais at either (636) 898-6725 or jdauphinais@consultbai.com.

Thank you.

Rod Williamson
Executive Director of ABATE

cc: Jim Dauphinais
    Sean Gallagher
Hi Julie,

Sorry for the delay in getting comments to you on this report. Our comments are as follows:

- The report does a good job at explaining the various components of standby rates – which they do through explanation of the DTE and Consumer’s standby tariffs. Overall the report is balanced and represents the view of the participants.
- The rate comparisons to UMERC and UPPCO included emphasizes the vast difference in standby charges, but we wouldn’t want to characterize those tariffs as being more appropriate because they charge lower standby charges for minimal outages – that isn’t necessarily reflective of cost-based service.
- The Concept Model Standby Rate Tariff (draft) provided by MCA should be identified as such, so others do not view it as a consensus document nor take it as Staff’s recommendations (which it does not represent). Some of the recommendations in that concept draft are counter to cost-based ratemaking.
- The solar standby tariff (#7) recommendation was a surprise. No major disagreement with it, but more time is needed to consider this recommendation.

Please let me know if you would like to discuss further with the team or have questions or comments.

Thank you.

Jessica Woycehoski
Energy Resources - Client Liaison
Rates & Regulatory Affairs
O: 517-393-2465 | C: 517-315-7365
WORKING TO DELIVER THE ENERGY YOU NEED, WHENEVER YOU NEED IT.
THAT’S OUR PROMISE TO MICHIGAN!

Please consider the environment before printing this email
June 6, 2017

Ms. Julie Baldwin  
Electric Reliability Division  
Michigan Public Service Commission  
7109 West Saginaw Highway  
Lansing, MI  48917

RE: DTE Electric Company Comments on the Standby Rate Working Group Supplemental Report

The purpose of Standby Rate Work Group (SRWG) Supplemental Report is to address the additional work performed by the SRWG which was primarily focused on evaluating standby service for Combined Heat and Power (CHP) applications. The original report issued on August 19, 2016, was more focused on evaluating standby service for renewable generation applications. The Michigan Public Commission (MPSC) Staff once again did a commendable job in organizing the sessions and providing all parties opportunities to make presentations and provide comments throughout the meetings. DTE Electric Company (DTE or Company) believes the additional SRWG meetings examining the standby service requirements for CHP projects provided benefits to all members of the SRWG.

DTE is supportive of economic distributed generation resources and has appreciated the opportunity to further explain its current standby tariff, as well as participate in discussions of other proposals.

The Company provides the following comments (in bold) with respect to Staff’s seven recommendations provided in the SRWG Supplemental Report.

1) To assist with standby service tariff transparency, a clear and concise description of the tariff structure and each term used should be included. Utilities should work with staff to ensure a good understanding of 1) the standby service tariff; 2) information available on the company’s website; and 3) the company’s preferred process for developers and customers to get standby service questions answered.

DTE supports this recommendation. In its current general rate case filing (Case No. U-18255), DTE has proposed adding additional definitions and explanation in its Standby Service Tariff Rider No. 3. In addition, DTE will
be providing a guide to understanding standby service including the process for requesting standby service on the Company’s website later in 2017.

2) Table 1 highlights the inconsistency in standby service tariffs across the state. Staff recommends that the Commission develop a standardized framework for standby service tariffs where possible. Staff recognizes there may be reason to deviate from the standard. Any differences should be justified and supported by the company.

DTE supports using a standardized framework for standby service tariffs which are consistent with the guiding principles and standby services outlined in PURPA and that follow cost of service principles.

3) For customers taking both supplemental and standby service, the standby service tariff should be structured to allow the standby capacity and delivery demand charges to be based on net load.

The Company is not clear on what is meant by “net load” in this recommendation. However, DTE does support that standby tariffs should be structured to recognize the demand interactions between supplemental and standby service.

4) Standby service tariffs, including the monthly customer charges, should be reviewed and, if necessary, updated in each utility’s rate case to ensure they are based on the most up-to-date cost of service principles. Daily capacity demand charges and the use of generator reservation fees and how the fee relates to the daily demand charge/pro-rated daily demand charges should be considered and discussed by the parties.

The Company is not clear who this recommendation is directed to. However, the Company supports the rights of any party to recommend or challenge components of standby rates in general rate case proceedings.

5) Standby service tariffs should include a reasonable capacity price differential to encourage scheduled maintenance, which in turn may reduce unscheduled outages. Limiting options to only off-peak time periods may not result in least cost to the utility.

DTE supports capacity price differentials related to scheduled maintenance. DTE’s standby service tariff currently provides a lower price capacity rate for schedule maintenance during on-peak periods.
6) Time of use charges for capacity and energy should be an available option for standby service customers.

The Company opposes this recommendation. DTE’s standby service tariff currently provides an on-peak demand charge and separate on-peak and off-peak energy charges. The Company does not currently offer hourly capacity pricing on any of its tariff offerings and does not assign capacity costs on an hourly basis in its cost of service modeling.

7) The method for determining the solar standby tariff billing criteria should be made clear on the tariff. Customers with solar generators should have the option to stay on their supplemental service rate schedule provided it has a demand charge for delivery services. A time of use charge for capacity and energy should be considered for these customers.

As stated in response to recommendation #6, DTE opposes using a time of use capacity charge as it is inconsistent with current cost allocation principles. Given the unique nature of solar as a distributed generation resource, the Company’s current tariff allows for standby contract capacity to be set based upon mutual agreement in order to meet the customer’s standby load.

Other Comments
With respect to comments made at the SRWG regarding a separate cost of service class for standby, DTE expressed the concerns with creating a separate cost of service class for standby service to the SRWG and in its filed testimony in Case U-18255. Creating a separate cost of service class for Rider 3 presents several cost of service concerns in addition to those mentioned in the Supplement report. Fundamentally, assigning power supply costs based on 4CP to a standby cost of service (COS) class where loads can be very irregular and can vary significantly at any point in time compared to normal loads, does not follow proper cost allocation principles. This is especially true in a small class, where generation size varies greatly and when one customer can influence the outcome of the entire class. In addition, the cost allocation process cannot be relied on to accurately assign costs to such a small class. Rider 3 revenues represent less than a quarter of 1 percent (0.25%) of the company’s revenues. Currently, the Company’s smallest COS class is 4 times larger than Rider 3. It is also appropriate to maintain Rider 3 in the D11 and Other COS class since the majority of standby service is provided to customers taking supplemental service on D11 and keeping the cost responsibility within the D11 and Other COS class thereby limits cross subsidies to other rate classes. Finally, there are power supply demand charge interactions between standby service and supplemental service that support keeping both Rider 3 and D11 in the same COS class.

In the Supplement report, a statement is made regarding cost of service for the D11 / R3 class. The report claims that 99% of the cost of service is assigned to D11 and 1% is assigned to Rider 3. Although accurate from a mathematical standpoint, this is not how DTE assigns costs to Rider 3. First, costs in the D11 and Other Class are only power supply related costs and, second, Rider 3 costs are not assigned based on 1% of the D11 and Other costs. Power supply costs are allocated to each rate in the D11 and Other cost of service
class based on each rates present revenues. This cost allocation method is not unique to Rider 3. This is the same method used to assign costs for any cost of service class with more than one rate product, such as D1 and Other class and the D3 and Other class.

**Summary**
As a result of the SRWG, there has been an increased common understanding of Standby service concepts and Standby rate design. This would not have been accomplished but for the efforts of the SRWG. The Company also learned through these meetings that it can improve upon the language contained in its Standby tariff, and more transparency may be needed with respect to Standby rate calculations. The Company is always open to suggestions from its customers and the MPSC Staff on how to enhance communication and enable our tariffs to be better understood, and thus will initiate efforts as listed above in both its tariff and on its website.

Any suggestions by parties to change DTE Electric’s Standby cost of service or rate design should be considered in the context of cost based rate making so that a specific small group of customers do not receive preferential treatment or subsidies at the expense of the larger customer base (or general population).

Sincerely,

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June 2, 2017

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Julie Baldwin, Manager
Renewable Energy Section
Electric Reliability Division
Michigan Public Service Commission

Re: PSC Standby Rate Working Group – Combined Heat & Power
Midwest Cogeneration Association and the Great Plains Institute
Comments on May 2017 Standby Rate Working Group Supplemental Report
MPSC Case No. U-17735

Dear Ms. Baldwin:

The Midwest Cogeneration Association (MCA) and the Great Plains Institute (GPI) appreciate this opportunity to comment on the Michigan Public Service Commission (“Commission”) Staff’s May 2017 Standby Rate Working Group Supplemental Report (“Staff Report”) in this proceeding. As you know, MCA and its partner GPI, together with GPI’s consultant 5 Lakes Energy, were active participants in the Standby Rate Working Group (“SRWG”) in 2016 and 2017, submitting presentations, written comments and analysis on the issues discussed in the Report. We commend the Commission for providing this informal forum for an in-depth discussion of standby rate tariff structure.

We appreciate the comments and information shared by the Staff, utility representatives, and other participants in the course of the SRWG’s proceedings. We believe the process resulted in an open discussion and greater appreciation of the issues faced by both standby customers and the utilities serving those customers. The Commission’s leadership in providing this forum is a model for the rest of the country.

We commend the Staff Report for generally capturing very well the issues, discussion, and positions of various participants in the SRWG. We believe the Report is well-organized and articulates the major issues involved in establishing fair standby tariffs. The following are our overall comments and some further suggestions for finalizing the Staff Report to fully reflect the MCA and GPI positions.
1. **Overarching Goal**

We concur with the Report’s statement that the “overarching goal of the SRWG is to ensure that any resulting standby service tariffs are based on the cost to serve self-generation standby customers and to increase transparency of the tariffs.” (Report p.1) We believe there was general agreement on these goals.

2. **Organization of the Report**

The Report properly reflects the SRWG’s identification of cost-of-service and rate design as distinct elements for review. It also properly reflects the key elements of rate design for standby tariffs that were discussed by the SRWG, and appropriately emphasizes the importance that standby charges be transparent to the customer.

3. **Cost of Service**

   A. **Separate Rate Class Issue**

The Report reflects the SRWG discussion of whether standby customers should be placed in a separate rate class. The Report notes that the Commission’s January 31, 2017 Orders in U-18014 for DTE and in U-17990 for Consumers require the utilities to perform separate cost of service analyses for standby customers in their next rate cases. Report p. 6. The Report makes the point that the Commission’s Orders in those cases do not necessarily mean that standby customers should be in a separate rate class for rate design.

The Report mentions: “Several SRWG participants commented that standby service customers should be placed in their own separate class so that the load and capacity and energy coincidence factors can be recognized and factored into the rates.” Report p. 6.

**Comment:** MCA/GPI support the Commission’s Orders requiring separate cost of service studies for standby customers and agree with the Report’s conclusion that “Establishing that the costs allocated to standby customers are cost of service-based will build the foundation for developing an effective rate design and standby service tariff.” Report, p. 6. We believe DTE and Consumers should provide standby service cost of service studies in the new pending rate proceedings, U-18255 and U-18322. MCA/GPI believe separate cost of service studies for standby customers is critical, particularly for base-load non-intermittent standby customers such as cogeneration customers, and that the assumptions underlying that analysis must be examined and supported with utility data.

   B. **Cost of Service Assumptions Affecting Rate Design**
Comment: The Report touches on the SRWG’s discussion of the cost-causation assumptions underlying some elements of DTE’s and Consumer’s current standby tariffs in the section titled “Standby Service Tariff Fairness,” at p. 18. We offer the paragraphs below as an addition to the Report summarizing the other SRWG participants’ different views on standby customer cost causation:

“A key cost of service issue and related rate design issue for standby tariffs is whether standby rate customers impose the same capacity and delivery costs on a utility as does a full-service customer. In the SRWG proceedings, the utilities took the position that they are required to maintain firm power and delivery capacity equivalent to a standby customer’s load at all times because a forced outage may occur at any time.

“However, PURPA provides:

“The rate for sales of back-up power or maintenance power: (1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility’s system will occur simultaneously, or during the system peak, or both. 18 CFR § 292.305(c)(1)

“MCA/GPI and ABATE took the position that the utilities’ assumption that they are required to maintain excess capacity for standby customers is unsupported, especially for non-intermittent baseload standby customers, such as cogeneration customers, because of the low rate of forced outages experienced by those customers (5%), the corresponding demand taken off the grid the remainder of the time (95%), and the diversity of cogeneration and other customer load and demand in the utilities’ customer base. MCA/GPI provided the SRWG with a 2004 study performed by Oak Ridge National Labs on the operational reliability of 125 cogeneration systems, including a variety of cogeneration technologies, which found a forced outage rate (FOR) of approximately 5%, with half of the outages (2.5%) occurring during peak periods.

“To examine whether the utilities’ assumption was true, MCA/GPI and 5 Lakes Energy requested that DTE and Consumers provide customer data, without customer identification, allowing a determination of the coincidence of customer demand on the utilities’ capacity and delivery resources. The utilities declined to provide that data due to privacy concerns and the small number of customers in their territories currently utilizing their standby tariffs. To address this absence of data, MCA/GPI asked 5 Lakes Energy to undertake an analysis of typical cogeneration customer standby service coincidence utilizing the continuous operating data collected by the New York State Energy Development Agency (NYSERDA) in its unique, long-standing cogeneration database. 5 Lakes
Energy based its study on nineteen cogeneration facility customers in the New York ConEd territory for which the NYSERDA database had two years of continuous operating data (8760 hrs), including those customers’ usage of the ConEd standby service during that period. 5 Lakes Energy presented its study to the SRWG, including its findings on demand coincidence and recommendations for billing determinant accuracy. One of the key findings of the 5 Lakes NYSERDA analysis was that the standby users’ demand variation was inconsequential based on ConEd’s overall load diversity. 5 Lakes’ recommendation from that data was that “No distinction between standby and supplemental power appears warranted.”

“SRWG participants discussed 5 Lakes Energy’s analysis, but did not reach consensus on this issue. This is a subject which should be addressed in the new rate cases.”

4. Rate Design

A. Customer Charge

The Report notes that a customer’s normal rate schedule will include a monthly customer charge and also notes that Consumers’ standby tariff has an additional customer charge, while DTE’s does not. The Staff recommends that standby customer charges be reviewed by interested parties in the next rate case.

**Comment:** MCA/GPI’s position, as indicated in our best practices “model tariff” proposal presented to the SRWG and our written comments, is that standby riders should not include customer charges which are duplicative. However, an additional standby customer charge may be justified based on any additional administrative costs incurred by a utility as a result of the customer’s standby service. We concur that this is a subject which should be addressed in the new rate cases.

B. Generation Reservation Fee

The Report notes the rationale for a generation reservation fee is “to compensate the utility for the capacity that the utility must have available to serve a customer during an unscheduled outage of the customer’s self-generation unit.” The report then discusses the various parties positions on reservation fees ranging from no reservation fee to a fixed fee based on nameplate capacity times 12%, and the price signals sent by each approach for efficient cogeneration system operation.

**Comment:** MCA/GPI believe our position on this important point is not fully explained in the Staff Report. We offer the paragraphs below as an addition to the Report summarizing MCA/GPI’s position:
“MCA and GPI take the position that reservation fees are a poor mechanism for recovering a utility’s generation capacity costs which can more accurately and transparently be recovered in a daily, ‘as used’ generation demand charge. They point out the poor relationship between reservation fees and utility costs as demonstrated by the 5 Lakes Energy statistical analysis of billing determinants presented to the SRWG. The 5 Lakes Energy NYSERDA analysis indicates no excess capacity is required to be maintained for standby customers. MCA/GPI believe a utility capacity cost for ‘standing ready’ must be cost justified by the utility in the pending rate cases.

“MCA/GPI further note that DTE’s reservation fee formula results in a minimum charge to standby customers which is equivalent to a 12% outage rate, while the 2004 ORNL Report MCA provided to the SRWG found that cogeneration systems back in 2004 averaged a 5% FOR. MCA/GPI also believe cogeneration system reliability, if anything, has improved since 2004.

“MCA/GPI also believe that reservation fees are a counter-productive charge in terms of incentivizing a customer’s minimum use of utility capacity. In the best case, where a customer’s forced outage rate (FOR) is the basis of the reservation fee, it is still just an estimate and fails to incentivize better self-generator performance. In the worst case, it is a fixed charge, such as DTE’s formula, with no relationship to cost causation, which actually dis-incentivizes better self-generation performance.

“MCA/GPI are also concerned that generation reservation fees may duplicate generation demand charges that are also justified by utilities as necessary to recover costs for capacity which must be maintained for standby customers.”

C. Power Supply Standby Charges – Demand

i. Statement of the Purpose of Demand Charges

The Report states that the “purpose of [power supply standby demand] charges is to recover costs for the capacity and energy used by the customer and contribute to the utility’s cost to have generation capacity standing ready to serve the customer in the event of an outage.” Report, p.10.

Comment: MCA/GPI respectfully believe this sentence misstates the rationale for power supply demand charges and could be misleading in terms of the identification of costs that should be recovered under a demand charge.
First, it isn’t clear what “energy” costs are included in a “demand” charge. For the sake of clarity and transparency, we believe all of a utility’s “energy” costs should be recovered separately under the “energy” charge.

Second, we are concerned that this sentence suggests that the demand charge serves the same function as a reservation fee – compensating the utility for “standing ready to serve the customer in the event of an outage.” As stated above on the topic of reservation fees, we believe utility costs for “standing ready” have not been demonstrated and must be cost justified by the utility in a cost of service study. Indeed, the 5 Lakes Energy NYSERDA analysis indicates no excess capacity is required to be maintained for standby customers. But, even more troubling, DTE and Consumers also charge a reservation fee based on the same rationale. Including “standing ready” as a rationale for both reservation fees and demand charges could result in confusion in the identification of costs and double recovery for the utility.

MCA/GPI suggest that the rationale for standby customer demand charges should be re-stated on p. 10 simply as follows:

“The purpose of [power supply standby demand] charges is to recover the costs for the capacity used by the customer.”

ii. DTE’s Power Supply Demand Charge

a. Definition of Standby Demand

The Report correctly points out that DTE’s Rider 3 includes a good definition of “Standby Demand” which allows a standby customer who is able to reduce its load (or otherwise reduce use of the utility’s power) to avoid standby demand charges when the customer is operating below its contracted supplemental demand.

Comment: MCA/GPI concurs that this is an appropriate definition which allows the standby customer “self-help” flexibility and avoids double charging for supplemental and standby demand. We found Consumer’s standby tariff to be unclear on this point and suggest that this same, clear definition of “Standby Demand” should be included in Consumer’s tariff.

b. DTE’s Demand Charge Calculation

The Report also correctly points out that DTE’s Rider 3 effectively sets standby demand charges per kW day at 32% of the cost of full-service. As a result, “After three full, on-peak outages during the month, the standby customer is paying the full service rate power supply demand charge.” Report, p. 13. Also, DTE limits standby demand charges by way of a “Daily Demand Cap.” The three calculations that a standby
customer must perform to determine its power supply demand charge are shown on p. 12 of the Report.

Comment: MCA/GPI believe the DTE power supply demand charge formula is both unnecessarily complicated and unfair to standby customers. With a daily charge set at 32% of the cost of a full month of service, DTE’s tariff on its face is excessive and unrelated to DTE’s actual daily capacity costs, and thus not cost justified. Further, the demand “cap” sends precisely the wrong price signal for efficient use of the utility’s generation resources. To ensure that MCA/GPI’s position on this important point is preserved in the record, MCA/GPI request that the following paragraphs be included in the final Report:

“MCA/GPI take the position that DTE appropriately charges a daily, on-peak demand charge, but that DTE’s daily charge at the rate of 32% of a full month of service is excessive, is not proportional to the costs a standby customer imposes on the utility, and discriminates against standby customers. MCA/GPI believes these charges must be cost justified by the utility in a cost of service study.

“MCA/GPI also point out that the combination of DTE’s minimum reservation fee, high daily charges, and “daily demand cap” penalizes standby customers who operate with high reliability and few forced outages with higher charges, while giving a cost reduction to standby customers who operate less efficiently. This incentivizes inefficient use of the utility’s generation resources.

“MCA/GPI believe DTE’s formula of high daily demand charges, a maximum daily cap, and a minimum reservation fee is also overly complicated and lacks transparency. This approach of minimum and maximum charges “hides the ball” on cost causation.”

D. Power Supply Standby Charges – Energy

Comment: MCA/GPI favor simplicity, transparency, proportionality, and efficiency in standby charges. All four of these goals are achieved by “time of use” energy charges where peak vs. off-peak pricing sends a strong signal to reduce grid consumption whenever possible during the utility’s peak demand.

E. Delivery Charges

The Report discusses the different methodologies used by DTE and Consumers to calculate the delivery charge. Consumers uses the self-generator customer’s generation name plate capacity times a fixed rate. DTE uses the customer’s contract capacity which is calculated based on its 1001st highest ½ hour of operation during June through October.
Comment: The separate high delivery charges contained in both DTE’s and Consumers’ standby tariffs were discussed in the SRWG in the course of reviewing the 5 Lakes Energy “Apples-to-Apples” comparisons and breakdown of each utility’s charges. MCA/GPI respectfully request that further discussion of this issue reflecting MCA/GPI’s position on these charges be included in the Report. We offer the following paragraphs for possible inclusion:

“MCA/GPI believe both of these methodologies suffer from the same inherent defect—i.e., they apply a fixed fee based on generation capacity (kW), effectively ratcheting this charge over a full month and not reflecting the low proportional delivery costs imposed by the self-generation customer. As can be seen in 5 Lakes Energy’s “Apples-to-Apples” comparison of charges for the scenario of a 2 MW cogeneration customer, the result of this ratchet is a high delivery charge, rendering the Michigan utilities’ standby charges substantially higher than they would be if based on the standby customer’s low proportion of use of the utility delivery resources. This can be seen in DTE’s and Consumer’s standby charges in every operating scenario examined in 5 Lakes Energy’s “Apples-to-Apples” breakdown of charges.

“As shown below, even in a “No Outage” month, DTE’s and Consumer’s standby customers who place zero demand on the utilities’ delivery resources must pay this high fixed delivery charge.

<table>
<thead>
<tr>
<th>No outage</th>
<th>Consumers</th>
<th>DTE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Charge</td>
<td>200</td>
<td>275</td>
</tr>
<tr>
<td>Delivery Capacity/Distribution Charge</td>
<td>8100</td>
<td>6760</td>
</tr>
<tr>
<td>Reservation Fee</td>
<td>0</td>
<td>3500</td>
</tr>
<tr>
<td>Demand Charges</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Energy Charges</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Subtotal of Monthly Delivery and Customer Charges</td>
<td>8300</td>
<td>7035</td>
</tr>
<tr>
<td>Subtotal of Monthly Reservation and Daily Demand</td>
<td>0</td>
<td>3500</td>
</tr>
<tr>
<td>Subtotal of Energy Charges</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>TOTAL</td>
<td>8300</td>
<td>10,535</td>
</tr>
</tbody>
</table>

“MCA/GPI question why Michigan utilities’ delivery charges should be a fixed monthly fee based on capacity rather than an “as used” daily demand charge, as both DTE and Consumers charge for power supply...
demand. MCA/GPI believe this fixed delivery charge fails the “best practice” design parameters as well as the Michigan Public Act 341 requirement that standby tariffs be non-discriminatory, “cost-based and just and reasonable” and the PURPA requirement for non-discriminatory standby charges. 18 C.F.R. 292.305(a)(1)(ii) (“Rates for sales ...shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.”) As a fixed monthly fee is not proportional to a cogeneration customer’s low use of the delivery resources, MCA/GPI take the position it is discriminatory and not cost-based, just or reasonable. They also argue the fixed monthly delivery charge discourages efficient use of those resources.

“The Staff recommend that this issue be addressed in the pending DTE and Consumers rate cases.”

**F. Standby Service Tariff Complexity**

The Report makes the statement that “Standby service tariffs are very complex, and staff realized early in the SRWG process that a cost of service based standby service tariff can only be simplified to a certain point.” Report, p. 16. The Report refers to standby customers’ interest in transparency and the significant technical potential for greater cogeneration deployment in Michigan and the utilities’ approach to working with customers. The Report recognizes the prospective standby customer’s “need to be able to understand the standby service tariff well enough to run some initial economic evaluations to determine whether the customer is a reasonable candidate for a project.”

**Comment:**

MCA/GPI take the position that standby tariffs need not be complex and offered in the SRWG meetings both a “Model Tariff” and a one-page “Summary of Charges” table as specific mechanisms for breaking through the complexity of standby tariffs, focusing on “best practices” in four distinct buckets of charges, and summarizing charges succinctly for customers.

To ensure these recommendations are included in the Report, MCA/GPI suggest the addition of the following language in this section:

“**MCA/GPI’s Proposed Model Tariff**

“MCA and GPI take the position that standby charges should be unbundled, but need not be overly complex. The four key elements of a standby tariff are those “buckets” of charges depicted in MCA/GPI’s “Model Tariff” -- Customer Charge, Reservation Fee, Demand Charge, and Energy Charge. In Michigan, the Demand Charge is broken into a power supply demand charge and a delivery charge.
While MCA/GPI believe “standardization” of standby tariffs is not required, they argue incorporation of best practices for these four types of charges should be required and believe MCA/GPI’s “Model Tariff” presented to the SRWG provides a framework for reviewing each tariff for the elements of best practices in each category of charges. They argue that tariff provisions that incorporate these best practices should be as straightforward as possible. They believe DTE’s complicated formula for determining the power supply demand charge is an example of an overly complex approach. Unpacking this complexity, MCA/GPI argue that DTE’s approach hides high daily demand charges, a reservation fee based on unrealistic outage rates assumptions, and a misguided “demand charge cap.” They contend a better approach is a simple “as used,” non-duplicative daily demand charge. While Michigan law requires that the delivery charge be stated separately, they see no reason it should not also be based on an “as used” daily charge.

“MCA/GPI’s Proposed Summary of Charges Table

“MCA/GPI makes the point that the standby customer simply wants to know what his/her cost will be. While standby tariffs may differ, they recommended in the SRWG that the Commission require each utility to translate their tariff charges into a one-page “Summary of Charges” table clearly showing the tariff rates in each “bucket” of charges. In the SRWG proceedings, MCA/GPI offered two examples of such a table in Ameren Missouri’s standby rider and Otter Tail Power’s ‘standalone’ standby tariff.”

5. Standby Service Tariff Fairness

See our comments in Section 3.B above.

6. Standby Service Tariff Comparisons

We appreciate that the Report refers to 5 Lakes Energy’s “Apples-to-Apples” standby tariff comparisons of seven utilities provided by MCA/GPI and presented to the SRWG by 5 Lakes Energy and that the slides from that presentation are attached in the Report. The Report notes that the comparison tables highlight some dramatic differences in standby service costs across the four Michigan utilities studied.

The Report also notes that both Consumers and DTE agree that “benchmarking is important, but more research is needed to determine whether the comparisons are truly on an ‘apples-to-apples’ basis” and that “some state jurisdictions may have policy goals that might impact whether the standby service tariff is structured to fully collect costs from each rate class.” Report, p. 19.

Comment:
We concur that the “Apples-to-Apples” comparison of the utilities’ tariffs is helpful in identifying the range of different charges the cogeneration customer faces in different utility territories. The 5 Lakes breakdown of different operating scenarios and separate “snapshots” of different “buckets” of charges also highlight how different rate designs result in different overall standby service costs and different price signals for the customer. The “snapshots” also allow us to unpack how the utility is recovering its costs and whether the charges imposed are cost justified.

With regard to the issue of discerning whether other states share the same goals in standby rate design, MCA/GPI note that the primary other state used in the presented comparison – Minnesota – is similar to Michigan in a number of important ways, including in its focus on cost-justification. In Minnesota’s current standby tariff docket, in which Minnesota’s four major utilities proposed revised standby tariffs based on recommended best practices, the Minnesota Department of Commerce laid out the following key goals:

- Standby rates should be transparent, flexible, and promote economically efficient consumption;
- Standby rates should accurately account for all relevant value streams including both costs and benefits;
- Standby rates should simplify input data sets & methodology, where possible and warranted;
- Standby rates should provide neither an incentive nor a disincentive for distributed generation.\(^1\)

Because Michigan and Minnesota share the same goals with regard to improving standby rates, and in light of the fact that Minnesota specifically states that it does not wish to provide an incentive or disincentive for distributed generation, we believe it is clear that the “Apples-to-Apples” comparison with Minnesota utilities is valid. It should also be noted that Minnesota utilities include unbundled generation, transmission and distribution costs in their reservation fees and demand charges\(^2\). Therefore, the suggestion made by the utilities in our SRWG discussion that Michigan utilities’ separate delivery charges may be recovered in other charges in Minnesota is incorrect. Furthermore, the wide disparity among utilities within Michigan itself should not be ignored, as these are important flags for further discussion and analysis with regard to cost justification.

MCA/GPI believe that the data provided in the 5 Lakes “Apples-to-Apples” comparison is valuable not only for benchmarking, but also for facilitating a constructive conversation about the transparency of each utility’s standby tariff, and the impact that a utility’s approach to standby service has on real-world customers who may be interested in installing CHP. Wide discrepancies among utilities across state lines, or within a state, might be justified based on the actual costs incurred by the utility in serving

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\(^2\) Ibid, p. 4.
standby customers, but a key problem with the current approach to standby service is that the link between what standby customers pay and the costs they impose on a utility is extremely unclear. Without transparent rate structures, and without a clear understanding by utility representatives, regulators and stakeholders of how proposed tariffs are applied in a variety of outage scenarios, such discrepancies will naturally raise red flags as to fairness, and will raise important questions about whether a utility’s approach to standby service is discriminatory under PURPA.

7. Michigan Public Act 341

The Report references Michigan’s new Public Act 341 and its provisions expressly requiring Commission review to ensure that standby tariffs are non-discriminatory and are “cost-based and just and reasonable.”

Comment: MCA/GPI appreciates the reference to this new law and concurs with the Staff recommendation that this review should take place in rate cases wherever possible. We note that the two new pending rate cases for DTE and Consumers are a ready vehicle for this review.

8. Staff Recommendations

Comment:

MCA/GPI whole-heartedly support the Staff Recommendations and appreciate the leadership of the Staff in providing a path forward following the SRWG process.

With regard to recommendation No. 1, we respectfully suggest that a uniform “summary of charges” table, such as Ameren Missouri and Otter Tail Power include in their standby tariffs, would be most helpful in achieving tariff transparency and should be required by the Commission, as well as discussed with the utilities.

With regard to Recommendation No. 2, we respectfully suggest that the “model tariff” framework we presented to the SRWG may provide a starting point for the Commission’s development of a “standardized framework” for standby service tariffs in Michigan.

With regard to Recommendation No. 4, we agree it is essential that Michigan utility standby tariffs be reviewed in each utility’s rate case to ensure they reflect up to date cost of service principles. We concur that there is a particular need for the Commission to review the relationship between reservation fees and power supply demand charges. We also believe the Commission should review how those charges are structured, e.g., DTE’s outage rate assumptions, high daily charges, and “demand cap,” and the cost-justification and reasonableness of DTE’s and Consumers’ fixed monthly delivery charges.
MCA and GPI appreciate the opportunity to comment on the Staff Report and would again like to thank the Commission and Staff for their leadership on this important issue.

Sincerely,

Patricia F. Sharkey
Policy Director
Midwest Cogeneration Association

Anna Dirkswager
Program Manager
Great Plains Institute
June 2, 2017

Julie Baldwin, Manager
Renewable Energy Section
Electric Reliability Division
Michigan Public Service Commission
By email: Baldwinj2@michigan.gov

Dear Ms. Baldwin:

The Michigan Energy Innovation Business Council (Michigan EIBC), a business association of 100 companies engaged in Michigan’s advanced energy industry, is pleased to support many of the conclusions contained in the Michigan Public Service Commission Staff Supplemental Draft Report (Draft Report) of the Standby Rate Working Group organized under U-17735. Specifically, we endorse the Commission Staff’s statement that the “overarching goal of the [Standby Rate Working Group] is to ensure that any resulting standby service tariffs are based on the cost to serve self-generation customers and to increase transparency of the tariffs,” including “clear and concise definitions of the terms and billing determinants used within the tariff and all of the rate information necessary to calculate a monthly bill.” MPSC Staff Supplemental Report of the Standby Rate Working Group, May 2017, pg. 1. This goal is consistent with the comments previously filed by Michigan EIBC as part of the Working Group process, in which we urged the Commission “to ensure that any standby rates are transparent, reflect cost of service principles, and do not create arbitrary barriers to the installation of CHP systems in Michigan.”

Beyond simply requiring definitions of terms and conditions, Michigan EIBC urges the Commission to require a simple, one-page summary that details how the tariff actually works, allowing a prospective customer the ability to fully evaluate the economics of installing self-generation systems and decide whether to go forward. Adding this requirement would be consistent with the Staff’s stated goal “to simplify the standby service tariffs and make it easier for current standby service customers to understand the billing calculations and how their bills could be reduced” and for potential customers “to be able to fully evaluate how their utility rates will change if they undertake a self-service generation project.” Id., at 16. Indeed, as Staff noted in the Draft Report, “CHP project developers need to be able to understand the standby service tariff well enough to run some initial economic evaluations to determine whether the customer is a reasonable candidate for a project. Increased transparency in the tariff will be helpful for these early screening analyses.” Id., at 17.

In addition to transparency issues, Michigan EIBC applauds the Draft Report’s focus on developing a standardized framework for standby service tariffs where possible,
requiring utilities to justify and support deviations from the standard. As has been shown in comparing the treatment of similarly situated standby customers across four Michigan utilities, wide variations exist that appear not to be grounded in cost of service principles, serving instead to create serious and unjustified barriers to CHP utilization and stymie additional private investment in these systems. As noted in our initial comments, Michigan EIBC believes that standby rates are appropriate “only when they are based on accepted cost of service principles and fully reflect the costs and benefits of CHP to the larger grid – including capacity, diversification and reduction of load, and reduction of line losses. Rates that overstate the likelihood or impact of outages distort the market and serve as arbitrary disincentives to the installation and use of CHP systems.” With the inclusion of CHP as a system resource to be considered in utility integrated resource plans under 2016 PA 341, as well as the Commission’s recent decision on avoided cost calculations under the Public Utility Regulatory Policies Act (PURPA) in U-18090, there are well-grounded policy reasons to support efforts to encourage deployment of CHP resources in Michigan.

In order to ensure that rates are, indeed, based on cost-of-service principles, Michigan EIBC further supports establishing standby customers as a separate rate class. While Michigan EIBC notes the Staff’s argument that “there may not be enough standby service customers to warrant a separate class,” Id., at 5, we caution that the lack of numbers may in fact be at least partially attributable to arbitrary costs and a lack of transparency that causes many potentially interested customers not to install systems. Only by treating standby customers as a separate class for rate design purposes can the Commission fully ensure that rates are truly based on cost of service.

Michigan EIBC again applauds Commission Staff for their work in developing this draft Supplemental Report. We urge the Commission to continue to move forward with recommendations that increase transparency, ensure rates are based on accepted cost-causation principles, and remove remaining barriers to deployment of CHP systems in Michigan.

Sincerely,

Liesl Eichler Clark
President
Michigan Energy Innovation Business Council