Michigan Public Service Commission

Staff Report on Net Metering and Electric Utility Interconnection Issues

Case No. U-15113

October 1, 2007

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Executive Summary

Simplified Approach to Net Metering

On February 27, 2007, the Commission issued an Order in Case No. U-15113 which included directing the Michigan Renewable Energy Program Ratemaking and Net Metering Committee to form a task force comprised of representatives from MPSC Staff, utilities, and interested parties to seek a new consensus and report to the Commission within 90 days on a simplified approach for net metering for inverter based systems smaller than 10 kW. The Staff report on interconnection procedures is due by September 30, 2007.[1]

To initiate the process, Staff reviewed the net metering issues identified during the investigation and developed a draft net metering proposal (March 2007 Staff Net Metering Proposal). All proposals and comments received can be found in Appendix 1 to this report. The March 2007 Staff Net Metering Proposal was posted on the Under 10 kW Net Metering & Interconnection Procedures Workgroup webpage and written comments were requested by April 16, 2007. A public meeting was held on May 2, 2007 to discuss the proposal. At this meeting both Consumers Energy and Detroit Edison explained how they would implement the March 2007 Staff Net Metering Proposal. Both utilities indicated they were in agreement with some portions of the March 2007 Staff Net Metering Proposal but there were some elements, such as allowing customers to use their existing meters, where the utilities did not agree with Staff.

Staff continued working with Consumers Energy and Detroit Edison to try to reach agreement on further simplifications to their net metering programs. Both utilities worked with Staff to explain cost recovery implications of further simplification. In August 2007, Staff developed a new net metering proposal for the workgroup's review. Comments from 19 parties were received on September 10, 2007. Based on the comments it is clear that consensus on a simplified approach to net metering could not be reached by this workgroup.

Since the workgroup did not reach a consensus, for the Commission's consideration, Staff proposes that utilities offer, at least to all net metering customers with 10 kW and under inverter-based systems, the net metering program shown in **Box 2**. This provides a simplified approach to net metering and is a compromise between the true net metering program sought by net metering advocates and the complex programs offered by Consumers Energy and Detroit Edison. The Staff proposal requires only one meter. Because both utilities are planning to commence AMI programs, meter upgrade costs should be minimized. Any relevant rate making issues can be addressed in the utility's rate case.

Staff's net metering recommendation should not prevent utilities from offering a true net metering program. Utilities currently offering this type of net metering program may continue these offerings and the remaining utilities are encouraged to give serious consideration to adding this option.

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[1] See p. 8 of the Order in Case No. U-15113 at http://efile.mpsc.cis.state.mi.us/efile/docs/15113/0048.pdf.

Utilities with cost recovery issues should propose a plan for rate recovery in a rate case. If the Commission agrees with the Staff's recommendation, utilities should be directed to file revised net metering tariffs.

10 kW and Under Interconnection Procedures

In the February 27, 2007 Order, the Commission directed the Engineering Section of the Commission's Operations and Wholesale Markets Division to establish a workgroup to develop faster and less complex interconnection procedures for 10 kW and under interconnection projects.

As a starting point for the workgroup, in March 2007, Staff issued a proposal with new interconnection procedures and revised interconnection standards documents and requested comments. The proposed interconnection procedures were based on the language in the Interstate Renewable Energy Council's model interconnection procedures applicable to inverter based interconnection projects sized 10 kW and less.

Seventeen parties filed comments on April 16, 2007. Most of those comments referred to the net metering proposal but several commenters supported the Staff's interconnection procedures proposal, too. The utilities raised many concerns.

A public meeting was held on June 19, 2007 for the 30 kW and larger interconnection procedures workgroup. Some of the issues discussed were applicable to 10 kW and under interconnections also. Comments received on these issues indicated that the utilities would like to consider adopting interconnection rules that are very similar to those used in Wisconsin. The utility comments included a copy of Chapter PSC 119 Rules for Interconnecting Distributed Generation Facilities (Wisconsin Rules).[2]

Staff prepared a summary document comparing the key elements of the Wisconsin Rules to the current Michigan Rules. See Appendix 2 for the comparison document. Staff and at least several of the workgroup participants agree that many of the issues presently affecting Michigan interconnections would be addressed in a positive way, through implementing the Wisconsin Rules. An added benefit would be the administrative efficiencies Michigan's multi-state utilities with Wisconsin customers would be able to realize if very similar interconnection procedures are utilized for both states.

Staff requested comments from the workgroup on the Wisconsin Rules by September 7, 2007. The two sets of comments received indicate that there is support for using the Wisconsin Rules as a basis for Michigan's updated interconnection rules. Comments are included in Appendix 2.

Progress toward developing faster and less complex interconnection procedures is expected to continue. Staff anticipates that the Michigan Rules will be completely replaced with a new set of rules and that a new set of interconnection procedures will be developed to correspond with the new rules.

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[2] See Wisconsin Chapter PSC 119 Rules for Interconnecting Distributed Generation Facilities http://www.legis.state.wi.us/rsb/code/psc/psc119.pdf.

For UL 1741 certified equipment, Staff recommends that Michigan utilities be ready to complete installations with minimal delays. Staff suggests an approach whereby utilities would identify which inverters are being considered for future interconnections and that utilities analyze those inverters to learn whether there are any potential IEEE 1547 issues. If a possible IEEE 1547 issue is discovered through this process, the utility should identify the system modifications to accommodate the inverter and establish its process for completing such interconnections within the time allotted under the Michigan Rules.

30 kW and Larger Interconnection Procedures

The February 27 Order, directed the Engineering Section of the Commission's Operations and Wholesale Markets Division to convene a workgroup with these objectives:

1. Identify reasonable and achievable interconnection time deadlines.
2. Propose a system for determining whether interconnection costs are reasonable, actual costs.
3. Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections).
4. Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.
5. Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system.

The first task undertaken by this workgroup was to consider these five objectives and comment on the best way to achieve them. These comments were due on April 20, 2007 and are included in Appendix 2. Four sets of comments were received. An additional interconnection issue was identified by interested parties and Staff regarding insurance requirements and liabilities.

Staff reviewed the comments and developed a Staff discussion paper that was presented at a workgroup meeting held on June 19, 2007. Also at this same meeting, Detroit Edison made a presentation on power factor issues.[3]

Workgroup participants were invited to comment on the June 19, 2007 Staff discussion paper. Five sets of comments were received. Comments received on these issues indicate Michigan utilities desire to consider adopting interconnection rules similar to those used in Wisconsin.

Many of the issues presently affecting Michigan interconnections would be addressed by the Wisconsin Rules. An added benefit would be the administrative efficiencies Michigan’s multi-state utilities with Wisconsin customers would be able to realize if very similar interconnection procedures are utilized for both states.

[3] See the Detroit Edison presentation on power factor at http://www.michigan.gov/documents/mpsc/Unity_Power_Factor_Discussion_Latest_version_199782_7.pdf.

Based on issues identified during the interconnection investigation, several additions to the Wisconsin Rules were included in the Staff proposal sent to the workgroup for comments on August 22, 2007. Those additions were:

- Provide for a pre-application meeting between utility and project developer.
- Include a provision for the Commission to appoint expert(s) to provide technical expertise related to interconnection issues.
- Require distribution utilities to consult with transmission owners for all generator projects >2 MW and when total generation on a distribution line will exceed 10 MW.

Staff requested comments from the workgroup on the Wisconsin Rules and proposed additions by September 7, 2007. Two sets of comments were received and indicate that there is some support for using the Wisconsin Rules and several of the Staff's proposed additions as a basis for Michigan's updated interconnection rules.

Comments received indicate that Michigan utilities are generally receptive to adopting interconnection rules similar to those used in Wisconsin. Many of the issues presently affecting Michigan interconnections would be positively affected by adoption of the Wisconsin Rules. An added benefit would be the administrative efficiencies that multi-state utilities with Wisconsin customers would be able to realize by using similar interconnection procedures in Michigan.

Staff notes that Wisconsin has both Rules and Interconnection Guidelines. Michigan has Interconnection Standards (which are Administrative Rules) and Generator Interconnection Requirements (also referred to as Interconnection Procedures) which are approved by the Commission. Based on the progress of this workgroup, Staff is anticipating that the entire set of Interconnection Standards will be replaced with a new set of Administrative Rules similar to the Wisconsin Rules. It is expected that the new Michigan Administrative Rules will also trigger the need for a revised set of interconnection procedures.

Staff expects large portions of Michigan's existing interconnection procedures can be maintained intact, since great effort went into their development and they contain a lot of technical information related to Michigan utility distribution systems. Updating the current interconnection procedures to reflect the Wisconsin Rules should be an option considered by this workgroup. However, the standardized application form and interconnection agreement used in Wisconsin should be given serious consideration. During the rulemaking process, consideration must be given to whether some of the more technical information in the Wisconsin Rules, might be better placed in the Interconnection Procedures so that if future changes are necessary, these changes can be accomplished with a Commission Order; without formal rulemaking.

Introduction

On October 24, 2006, the Commission, in Case No. U-15113, commenced an investigation into the interconnection of independent power producers with utility systems. As part of the investigation, a Staff Report on Utility Interconnection Issues was submitted to the Commission on January 31, 2007.[4]

On February 27, 2007, the Commission issued an Order (February 27 Order)[5] in Cases Nos. U-15113 and U-15239 which commenced a rulemaking proceeding in docket number U-15239 to amend the Interconnection Standards R460.481 to R460.489, approve certain recommendations and direct the development of the following workgroups to further examine net metering and interconnection issues:

- The Michigan Renewable Energy Program Ratemaking and Net Metering Committee was directed to form a task force comprised of representatives from the Staff, utilities, and interested parties to seek a new consensus and report to the Commission within 90 days on a simplified approach for net metering for inverter based systems smaller than 10 kW.

- The Engineering Section of the Commission's Operations and Wholesale Markets Division was tasked with the responsibility of establishing a workgroup to develop faster and less complex interconnection procedures for 10 kW and under interconnection projects. A Staff report on the progress of the workgroup is due no later than September 30, 2007.

- The Engineering Section of the Commission's Operations and Wholesale Markets Division was directed to convene a separate workgroup for interconnection projects of 30 kW or larger. A Staff report on the progress of the workgroup is due no later than September 30, 2007.

Webpages were developed for the Under 10 kW Net Metering & Interconnection Procedures Workgroup[6] and the 30 kW and Larger Interconnection Procedures Workgroup.[7] To simplify the administration of issues applicable to under 10 kW sized generators, the net metering and interconnection topics were covered on one webpage with one email list. As of September 5, 2007 there were 45 email participants on the 30 kW and Larger Interconnection Procedures Workgroup and 84 email participants on the Under 10 kW Net Metering & Interconnection Procedures Workgroup[8].

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[4] See the January 31, 2007 Staff Report on Utility Interconnection Issues, at http://efile.mpsc.cis.state.mi.us/efile/docs/15113/0047.pdf.

[5] See http://efile.mpsc.cis.state.mi.us/efile/docs/15113/0048.pdf

[6] See http://www.michigan.gov/mpsc/0,1607,7-159-16377_43420_45811-164471--,00.html

[7] See http://www.michigan.gov/mpsc/0,1607,7-159-16377_47107_47111---,00.html

[8] Both workgroup email lists are open to the public. See http://www.cis.state.mi.us/mpsc/about/subscribe-listserv.htm to participate.

Simplified Approach to Net Metering

The Michigan Renewable Energy Program Ratemaking and Net Metering Committee was directed to form a task force comprised of representatives from the Staff, utilities, and interested parties to seek a new consensus and report to the Commission within 90 days on a simplified approach for net metering for inverter based systems smaller than 10 kW (These inverter based systems will likely be solar photovoltaic and wind.) Many of the people interested in participating on the net metering task force also wanted to be part of the 10 kW and under interconnection procedures workgroup, so a single webpage and email list was developed for the combined Under 10 kW Net Metering & Interconnection Procedures Workgroup.[9] It was generally assumed, for purposes of the workgroup discussions, that Michigan's existing tariffs for net metering would continue to apply to customers with non-inverter based systems and generators larger than 10 kW.

As directed by the Commission in the February 27 Order, on May 25, 2007, Staff issued a report on the workgroup's progress toward reaching a new consensus on a simplified net metering program design (May 25 Report).[10] This interim report includes a brief net metering history and background, a summary of current net metering billing methods available to utilities based on the framework of the Commission approved consensus agreement,[11] and Staff's March 2007 draft simplified net metering proposal. The May 25 Report also includes descriptions of Consumers Energy's and Detroit Edison's responses, explaining how those utilities proposed to implement the Staff's proposal. Staff concluded in the May 25 Report that progress was being made toward resolving net metering issues, but that more time was needed. Staff committed to addressing net metering issues in this final report.

In an effort to make this report a complete record of the interconnection investigation activities subsequent to the February 27 Order, all substantive information included in the May 25 Report is repeated here.

Brief Net Metering History

In its May 18, 2004 Order in Case No. U-12915, the Commission directed Staff to work with the newly created Michigan Renewable Energy Program (MREP) Ratemaking & Net Metering committee to develop a statewide net metering proposal for the Commission's consideration.[12] Commission Staff, representatives of regulated utilities, and other interested parties worked

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[9] See the webpage for the Under 10 kW Net Metering & Interconnection Procedures Workgroup at http://www.michigan.gov/mpsc/0,1607,7-159-16377_47107_47112---,00.html.
[10] See the May 25, 2007 Staff report at http://efile.mpsc.cis.state.mi.us/efile/docs/15113/0050.pdf
[11] See the consensus agreement at http://efile.mpsc.cis.state.mi.us/efile/docs/14346/0001.pdf.
[12] See the Order at http://efile.mpsc.cis.state.mi.us/efile/docs/12915/0136.pdf.

cooperatively during late 2004 and early 2005 to develop a net metering proposal. A consensus agreement was approved by the Commission, with amendments, in a March 29, 2005 Order in Case No. U-14346.[13] The consensus agreement defines net metering:

> "Net metering is an accounting mechanism whereby retail electric utility customers who generate a portion or all of their own retail electricity needs are billed for generation (or energy) by their electric utility for only their net energy consumption during each billing period." (Consensus Agreement, p. 3).

The net metering program is for customers with generator capacity sized under 30 kW. A utility may voluntarily set its limit to under 150 kW; however, all Michigan utility net metering tariffs currently set the size limit at under 30 kW.[14] A second size limit requirement is that a customer's generator must be sized to meet the customer's needs. The intent is for the net metering program to assist the customer in meeting their own power and energy requirements, but net metering is not intended for customers who expect to make money through the sale of electricity. A third size limit is for the combined capacity of all net metered generators on any utility's system; not to exceed either 100 kW or 0.1% of the utility's peak system demand, whichever is greater.

Net metering tariff sheets for each utility are available on the Commission's website.[15] The consensus agreement requires utilities to report net metering data annually to the MPSC MREP Staff by September 30 of each year to cover the 12-month period ending June 30.

Current Status of Michigan's Net Metering Program

As of June 30, 2006 (the most recent net metering reporting period), Michigan had 8 customers participating in net metering. All but two of these customers began net metering well before 2005, when the current net metering program became effective.[16]

Most utilities are reporting increased numbers of customer inquiries about net metering, and on that basis the utilities believe interest in the program is growing. Commission Staff has also received an increase in the number of net metering inquiries.[17]

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[13] See http://efile.mpsc.cis.state.mi.us/efile/docs/14346/0031.pdf .

[14] The Consensus Agreement provides for multi-state utilities presently offering net metering in Michigan and other states through MPSC-filed tariffs to continue those offerings in their present form as compliance with the consensus. We Energies and Xcel Energy, notified the Commission they would continue providing net metering service under existing tariffs.

[15] See http://www.michigan.gov/netmetering. MPSC does not regulate municipal utilities in Michigan. Staff is presently unaware of net metering programs, if any, for the 42 municipal electric utilities in Michigan.

[16] The three We Energies participating customers indicated in Table 1 have been net metering since the 1980s. Ontonagon Rural Electric Association has one customer that began net metering around 1999.

[17] Prior to 2007, Commission Staff did not have a specific tracking mechanism for net metering inquiries. Codes were established for this purpose in early 2007, so that the Commission's Service Quality Inquiries data tracking system now includes specific codes for net metering and interconnection. Staff will track and report net metering inquiries in future reports.

Table 1 shows a summary of net metering installations for the three Michigan utilities with net metering customers. During this first year of the program, there have been some reported difficulties related to the timely completion of utility interconnection procedures. Utilities reported 7 pending net metering applications, as of June 2006.

Table 1: Summary of Net Metering by Utility, Year Ended June 30, 2006

Company	Number of Participating Customers (June 2006)	Net Metering Technology Types			
		Wind	Solar	Biomass	Hydro
Alger Delta Co-op	3	1	1		1
Ontonagon County REA	2[1]		2[1]		1[1]
We Energies	3	1			2
Michigan Total	**8**	**2**	**3**		**4**
[1]One customer has a combined system including both solar and wind generators.					

Michigan Net Metering Programs

Michigan utility net metering programs are not identical for all utilities. In the May 29, 2005 Order, the Commission noted that the consensus agreement provides enough of a framework so that all of the programs will be substantially similar.

The consensus agreement offers utilities flexibility in billing methods and provides for at least four different net metering billing methods. Below, Staff has explained the four billing methods available to utilities under the consensus agreement.[18]

Staff believes that all Michigan utilities are currently using billing methods 1, 2, or 3 and that none is using billing method 4. In general, each utility uses one billing method for all its net metering customers. However, whether a customer has three-phase or single-phase service may impact available metering methods and even billing methods.

[18] Staff attempted to prepare a complete listing of possible billing methods; however, there may be billing methods and slight variations that were inadvertently missed. The information used to compile the Michigan utility net metering billing method descriptions included utility tariff sheets and sample bill calculations filed as part of the U-15113 interconnection investigation.

Billing Method 1 – Customer Site Usage

This billing method determines the customer's total site usage. Total site usage is the sum of electricity delivered by the utility and the portion of on-site generation utilized by the customer. The total site usage quantity is either directly measured or calculated. Metering must be installed to determine the customer's total on-site generation output, electricity deliveries from the utility (inflow), and customer generation delivered to the utility (outflow). The necessary data can be gathered using 2 or 3 meters.[19] The state's two largest utilities – Consumers Energy and Detroit Edison – use variations of this billing method.

The bill is calculated based on the customer's total site usage. Then, the following credits are calculated and applied to the bill:

1. Generation Credit (Power Supply and PSCR[20] charges, applied toward the sum of on-site generation utilized by the customer and net excess generation or NEG[21])
2. Distribution Credit[22] (multiplied by the on-site generation utilized by the customer)
3. Surcharge Credit – for certain surcharges[23]

The consensus agreement provides that a utility may opt to record the Distribution Credit, Surcharge Credit, and the above market price value of the Generation Credit (if any) as net metering program costs that may be eligible for rate recovery, if the Commission so authorizes in a future rate proceeding.[24]

Detailed sample net metering calculations for Consumers Energy and Detroit Edison are provided in Appendix 1.

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[19] Consumers Energy generally uses a bi-directional meter that records both inflow and outflow and a standard meter on the generator, and the Company has been charging net metering customers approximately $477 for the installation of these two extra meters. Detroit Edison generally uses three standard meters to determine the customer's total generation output, inflow, and outflow, and the Company has been billing the net metering customer approximately $60 for the meters; payable in 12 monthly payments of $5 each. With this billing and metering approach, in addition to the meter charges from the utility, the customer is also responsible for the installation of extra meter sockets and their associated wiring.

[20] PSCR– Power Supply Cost Recovery factor is billed to customers for the current month per the PSCR clause in each utility rate book and pursuant to Act 304, Public Acts of 1982.

[21] Generation quantities in excess of the current monthly site usage will be carried over as NEG on a month-to-month basis until the end of the annual net metering billing cycle when any cumulative NEG quantities are granted to the utility. NEG quantities are the sum of the customer's generation in excess of the customer's current month on-site usage and the previous month NEG balance, if any.

[22] Detroit Edison calls this "Program Credit." For Detroit Edison net metering customers, this credit is equivalent to the distribution charges (per kWh) multiplied by the on-site generation utilized by the customer, in the month it is generated.

[23] Detroit Edison provides a surcharge credit to reflect surcharges applicable to the company's Program Credit (see footnote 13). Consumers Energy net metering customers are being billed for surcharges based on the customer's total site usage, which applies surcharges to both the energy generated and used on-site by the customer and the energy delivered by the utility.

[24] See the discussion of rate recovery issues, at p. 27.

Billing Method 2 – Utility Deliveries

Bills are calculated based on the electricity delivered by the utility (inflow). Net metering credits are given for the customer's generation deliveries to the utility (outflow) and are usually valued at the generation portion of the retail electricity rate including PSCR charges. On customer bills, Michigan utilities typically term this generation portion, "Power Supply Charge." Metering for this option can be accomplished using a single bi-directional meter that separately records and reports both inflow and outflow quantities or two standard meters can be used, one each for measuring inflow and outflow.[25] NEG is carried forward to the next month in the same manner as Billing Method 1. Utilities opting for this simplified method are most likely not able to track program costs for lost distribution revenue for the portion of customer generation utilized on site.

For sample bill calculations using this billing method, please refer to the sample UPPCo bill included in Appendix 1.

Billing Method 3 – Net Energy Usage

Under this method, the customer bill is calculated using only the customer's net electricity usage (inflow kWh minus outflow kWh). This is also referred to as "true net metering." Metering for this option could include an electronic meter programmed to calculate the customer's monthly net energy usage, a single bi-directional meter capable of recording both inflow and outflow numbers, two standard meters for measuring inflow and outflow, or a single standard meter that can spin in either direction while accurately recording both inflow and outflow. This latter metering option is commonly referred to as having a meter that "spins backwards" or registers in reverse. Under this method, NEG would not necessarily accumulate. If the customer's rate schedule provides for a monthly customer charge, the customer will most likely be responsible for paying that full charge, as a minimum monthly payment, even if their net usage for the month is negative. Under this billing and metering scenario, customers are receiving the full retail rate (including both generation and distribution) for generation they export to the grid. This appears to be the simplest billing method with the lowest administrative burden to the utility. Utilities opting for this simplified method are not keeping track of lost distribution revenue for the portion of customer generation utilized on site.

For tariff sheets and sample bill calculations using this billing method, please refer to the sample We Energies bill included in Appendix 1.[26]

[25] If two meters are used, then in addition to any meter charges from the utility, the customer is also responsible for the installation of an extra meter socket and its associated wiring.

[26] Staff notes that the We Energies net metering program was already in place prior to the consensus agreement. The consensus agreement provides for multi-state utilities presently offering net metering in Michigan and other states through filed tariffs to continue those offerings in their present form as compliance with the agreement.

Billing Method 4 – Fixed Monthly Charge

No Michigan utility is currently using this method; however, the consensus agreement provides for utilities to recover transmission, distribution and other eligible costs through a separate rate charge designed to assure that the utility recovers approximately the same share of fixed transmission and distribution costs it would have received from the customer, absent net metering.

Net Metering Task Force Proposals

(for inverter based systems 10 kW or less)

Staff presented two proposals for the task force to review. The first proposal was presented in March 2007. After receiving comments from the task force, a revised Staff proposal was issued in August 2007.

March 2007 Staff Net Metering Proposal

In March 2007, Staff proposed a simplified net metering program for the workgroup to review. This program design closely mirrors Billing Method 4 described above. Staff did not propose any actual numbers for the minimum monthly fixed charge referenced in item number 4 in the outline of the March 2007 Staff proposal shown in the following Box.

March 2007
Staff Draft Net Metering Proposal

1. All inverters that comply with the following codes and standards shall be considered pre-certified, with no additional testing or certifications required:

a. UL 1741 Inverters, Converters and Controllers for Use in Independent Power Systems.

b. IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems and IEEE 1547.1 Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.

2. No later than 45 days after the Commission approves this [March 2007 Staff proposal], all utilities shall provide, and keep continuously updated on the utility's website, a listing of inverter models that are pre-certified for use with installations of systems sized 10 kW and less. The inverters listed must be generally considered suitable for connection with the distribution system and a detailed review of the inverter's engineering design, characteristics, or suitability shall not be necessary to approve its use or installation by a project developer. A utility's list may reference or incorporate by reference inverters certified by a recognized national testing laboratory. A utility may either provide a list of all specific inverters that it considers pre-certified, or a utility may simply provide a statement indicating that all inverters that are UL 1741 listed shall be considered pre-certified.

3. If any additional interconnection equipment shall be required in specific circumstances, such as disconnects or monitoring equipment, each item of equipment shall be specified and included in the utility's pre-certified equipment listing on its website.

4. Net metering customers will pay a minimum amount each month to cover an appropriate portion of customer-based fixed charges. This minimum monthly fixed charge will be the only contribution made by net metering customers to utility customer-based, fixed, and variable distribution costs. This minimum bill amount will be established by the Commission for each utility. Each utility shall provide its proposed net metering rate information and draft tariff sheets for each eligible rate class based on this methodology not later than 30 days after the Commission approves this consensus.

All other charges for net metering customers shall be paid through the utility's variable energy charge rate, according to the customer's net metered use, after accounting for net excess generation, if any, as described in paragraph 6.

5. A rule change to R480.3605 will be sought to allow meters to reverse register (that is, to spin backward). R480.3605 presently reads as follows:

> R 460.3605 Metering electrical quantities.
> (3) Metering facilities located at any point where energy may flow in either direction and where the quantities measured are used for billing purposes shall consist of meters equipped with ratchets or other devices to prevent reverse registration and shall be so connected as to separately meter the energy flow in each direction.

6. Net metering for these customers can then utilize the simplest single-meter approach, where customer net excess generation is credited either on a per kWh basis, or at the same retail price as the customer pays for energy received from the utility. Utilities shall be strongly encouraged to use the least expensive meter available, such as an electromechanical, energy-only meter.

Net metering customers will pay for their metered utility service on a per kWh basis, including only variable energy charges. The customer credit per kWh for net excess generation shall be based on the retail price paid by the customer, including all energy and power supply cost recovery charges.

7. If a participating utility seeks additional metering data to assist with utility planning needs or for the evaluation of the net metering program, then with customer approval the utility could be allowed to install and operate additional meters, but all costs associated with the additional meters would not be the responsibility of the net metering customer.

8. At the end of a net metering year, the utility will carry the customer's net excess generation forward to the next year or issue a check to the customer with the net excess generation valued at the utility's average annual avoided cost rate for the year.[27] If a customer moves outside the utility's service territory, any remaining net excess generation balance is payable to the customer at the utility's last annual average annual avoided cost rate.

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[27] A utility's "avoided cost rate" is already determined by the Commission through its regular rate setting processes.

Fifteen parties filed comments including one set of comments from the regulated utilities. A complete set of comments is included in Appendix 1.

A public meeting was held at the Commission offices on May 2, 2007. Twenty-two people attended the meeting in person and several more attended via teleconference. Staff presented its net metering proposal and then both Detroit Edison and Consumers Energy presented descriptions of how they would propose to implement the Staff net metering proposal. Discussion was held throughout the meeting.

During the meeting, Staff requested that Detroit Edison and Consumers Energy provide their proposals in writing and include sample bills for the task force to review by May 16, 2007. Both proposals are summarized below.

<u>Consumers Energy Proposal</u>

Consumers Energy proposes the following for less than 10kW Net Metering generators that are IEEE 1547 and UL compliant:

- A single bidirectional meter which eliminates the requirement for the customer to install a generation meter and lowers the incremental metering costs. Customers will have the option to purchase and have installed a generation meter, but it will not be used for billing purposes.

- The bidirectional meter will measure energy provided by Consumers Energy (input) and separately measure the customer's excess on-site generation sent back to the electric grid (outflow). This configuration is compliant with existing metering standards and maintains data on energy provided by the utility, for use in the Commission's PSCR process.

- The typical incremental cost for a residential customer is approximately $420 and may be paid by the net metering participant in one of 3 ways (to prevent intraclass subsidization as stated in the Net Metering Consensus Agreement);[28]

    1. a single payment up-front,
    2. in 12 equal installments on the customer's electric bills, or
    3. a flat monthly charge that is determined by applying an appropriate fixed rate charge to the incremental cost (would result in a perpetual monthly charge of roughly $4 per month for a typical residential net metering participant.)

- Continuous carry-over of Net Excess Generation (NEG) credits - which eliminates setting the customer NEG balance to zero at the end of the program year.

[28] This analysis assumes that a new specialized electric meter is required. The estimated $420 cost includes both the meter and Consumers Energy labor costs associated with its installation. New "smart meters" planned for installation in both Consumers Energy and Detroit Edison service territories are thought to be capable of measuring and recording both inflow and outflow, at little if any incremental cost. See discussion on p. 24.

- A monthly fixed distribution charge based on the customer's average kWh monthly consumption using the most recent 12-month history prior to net metering. Consumers will review and modify the average kWh consumption used for purposes of determining the distribution charge if the customer has a verifiable change in their connected electric load. This charge was approximately $20 per month in the example calculation provided for a residential customer using 750 kWh per month.

- Consumers Energy proposes to continue to inspect and test each installation to ensure it properly de-energizes from a de-energized circuit through the period covered by the Consensus Agreement. The customer will be responsible for this cost.

- The Net Metering customer is provided NEG credit for (1) Power Supply (energy charges) and (2) Power Supply Cost Recovery (or PSCR) charges and adjustment factors, at the same rates as specified in the customer's tariff. Customer credits for Power Supply and PSCR will be applied up to the amount charged on the customer's current monthly bill for those items.

- Consumers Energy will streamline the application process for projects of this size and improve customer program materials for the Net Metering Program.

Detroit Edison's Proposal

1. Detroit Edison proposes to eliminate the meter charge for all net metering customers regardless of size. Detroit Edison does not require customers with on-site generation that purchase standby service and sell excess energy to the utility to pay for their inflow, outflow, or generator meters. Placing the meters into rate base will have an inconsequential impact on ratepayers even at high levels of participation and utilizing the most costly metering configuration conceivable. Furthermore, meters being evaluated for potential automated meter interrogation applications purchased in quantity will provide the data for inflow, outflow and generation at a lower cost.[29]

[29] For customers with on-site generation on rates other than net metering, Detroit Edison does not require payments for inflow, outflow, or generator meters. Charges for the meters for non-net-metering customers have been included in Detroit Edison's rate base. It is expected that placing net metering meters into rate base will have inconsequential impact on ratepayers, even at high levels of participation and utilizing the most costly metering configuration conceivable. Furthermore, new "smart meters" are presently being evaluated by some Michigan utilities for potential automated meter infrastructure (AMI) applications. Smart meters are expected to be capable of providing required net metering data at no incremental cost.

2. Detroit Edison proposes to offer all net metering customers the option of installing the generation meter at a remote location accessible to the customer's telephone line if the customer agrees to allow Detroit Edison to use their personal telephone service to interrogate the meter. This will significantly reduce or eliminate the customer's wiring expense associated with locating all metering at the service drop, while providing the customer with all the benefits of the full metering option.

3. Detroit Edison proposes to utilize, whenever feasible, meters capable of metering inflow and outflow independently for residential net metering customers that will replace the existing meters without modifying or changing the existing meter enclosures. This will completely eliminate any expense associated with metering inflow and outflow for residential net metering customers. Bidirectional meters may also be utilized for non-residential customers if suitable metering is available.

4. Detroit Edison proposes to offer a net metering tariff alternative (hereinafter the "10 kW Option") for inverter based systems with on-site capacity of ten kilowatts or less as an option to qualified customers.
    a. Customers must take service on energy only rates.
    b. Greenfield sites, which by design include generation that qualifies for net-metering to be constructed with the site development, will not qualify for the alternative net metering tariff option.
    c. Generation will not be metered.
    d. Inflow and outflow will be metered independently.
    e. NEG as measured by the outflow meter will be carried over from month to month limited to a 12-month billing cycle specified by the customer.
    f. Inflow will first be supplied from the customer's NEG balance from previous months and then be supplied by Detroit Edison.
    g. At the end of the customer-specified 12-month cycle the NEG balance if any will be set to zero. The value of any NEG balances set to zero, at the annual average avoided cost value paid to customers selling excess energy to Detroit Edison, will be applied to recoverable costs associated with the net metering program.
    h. The customer will be charged a system use charge equal to:
        i. 1/12 of the site use for the twelve months preceding generation installation times the Distribution Energy Charge plus delivery surcharges specified for the customer's base rate. Or,
        ii. An estimate of 1/12 of the site use for twelve months without generation times the Distribution Energy Charge plus delivery surcharges specified for the customer's base rate. The estimate will be made from available site data and data for like facilities.
            1. If the customer and the Company cannot agree on an appropriate value for site use, the customer must take service under the full metering option.

       This charge would be approximately $36 per month for a residential customer using 750 kWh per month.
    i. The customer will not be charged any additional amount above the system use charge for the distribution system used by the customer to import power from the

utility, to export power to the utility and for using the utility to accomplish the storage effect of the battery system [the customer] avoid[s] [by net metering].

j. The customer will be billed for all power delivered to the site at the power supply rates and power supply surcharges specified for the customer's base rate

k. The customer will be given a credit for all power supplied from the customer's NEG balance from previous months delivered to the site at the power supply rates and power supply surcharges specified for the customer's base rate.

5. The existing three-meter configuration will continue to be offered without the current meter charges as the following benefits are provided which will not be provided by the proposed 10 kW Option: [30]

   a. The three-meter configuration provides a precise calculation of the customer's electric savings. There is no way to conclusively determine what the customer would have paid absent [their] generation without metering on generation.
   b. The three-meter configuration provides generation data, from billing grade meters, suitable for billing Renewable Energy Certificates the customer wishes to sell for profit. This data will not be available for customers selecting the proposed 10 kW Option.
   c. The three-meter configuration provides site consumption data for comparison to the historical use for customer usage evaluation. This data (previous month, previous year) will not be available for customers selecting the proposed 10 kW Option. The three-meter configuration allows a Program Credit to be provided for generation utilized on-site during the current billing period. This Program Credit will not be provided to customers selecting the proposed 10 kW Option as no measure of generation will be available.

Staff met with Consumers Energy and Detroit Edison over the summer to develop an understanding of their net metering proposals developed in response to the March 2007 Staff Net Metering Proposal. It was hoped that by having the customer make a full monthly payment toward distribution costs, a simple net metering program design whereby the customer's existing meter would spin backwards whenever electricity was sent out to the utility grid would be sufficient, but Staff concluded that the responses were, in fact, not markedly simplified, compared to the status quo. A key element of the Staff draft proposal was the use of the customer's existing standard electric meter. Many of the meters currently in use will spin backwards when a net metered generator exports electricity to the grid.[31] Meter upgrades and associated electrical wiring to add

[30] MPSC Staff does not fully agree with Detroit Edison's analysis of these issues. Most, if not all, inverters used for net metering will provide customers with data regarding the output of the customer's on-site generation. And, based on conversations between Staff and representatives from the Midwest Renewable Energy Trading <continued> <continued> System (MRETS; http://www.m-rets.com), it does appear that viable options will be available for those customers who wish to market renewable energy certificates (RECs) from their on-site generation, even if that generation is not metered using a separate billing grade meter.

[31] A rule change to the current MPSC Rule 480.3605 is being sought to allow meters to reverse register, which is the technical term for "spin backwards." See the discussion about Reverse Registration of Meters at p.25.

additional meters can cause the customer to incur substantial installation costs, depending on the type, quantity, and location(s) of meter(s) a utility might require. Staff believes, as many comments received from customers and installers indicate, that the extra costs associated with complex metering and billing approaches have resulted in what effectively result in significant and unnecessary disincentives to net metering.

Detroit Edison's response to the March 2007 Staff Net Metering Proposal included upgrading the customer's meter to a bi-directional meter, and putting the cost of the meter in base rates. Consumers Energy proposed to charge the net metering customer over $400 to obtain and install a bi-directional meter.

Net Metering Customers, Installers, Energy Office, and Advocacy Groups Request

During this interconnection investigation, potential and current net metering customers, installers, the Energy Office, and advocacy groups clearly told Staff that they wanted Michigan utilities to offer a simpler net metering program similar to the net energy usage method described above as Billing Method 3. This is also sometimes referred to as "true net metering". The net metering programs offered by Xcel Energy and We Energies include program design elements important to these workgroup participants. These utilities offer this type of net metering program to their Michigan customers because of the administrative efficiencies of offering a program similar to what is offered to their Wisconsin customers. The customer's current meter is used whenever possible and is allowed to spin forward and backward. This net metering program design is simple for the customer to understand and provides the largest financial incentive to net metering customers. Some commenters have suggested that net metering customer billing can be further simplified by implementing an annual or semi-annual billing system. Staff notes, however, that existing billing rules necessitate monthly billings.

Xcel Energy and We Energies Net Metering Tariff Highlights

- Available to any retail electric customer with generation of 20 kW or less.

- For non-time-of-day service customers, the existing meter used for retail electric service will normally serve to determine net energy usage and no additional charges are required.

- A participating customer receives a credit for energy delivered each month in excess of the amount used that month. The credit is equal to the full retail rate. We Energies customers receive a check from the utility when the credit exceeds $25.

- All Xcel Energy residential Michigan customers with normal metering configurations currently pay a $4.25 monthly customer service charge, regardless of their electricity usage. We Energies residential Michigan customers currently pay a $9.60 monthly facilities charge, regardless of their electricity usage.

Copies of Xcel Energy's and We Energies tariffs are included in Appendix 1. Based on comments and discussions that were part of this interconnection investigation, Staff believes that this type of net metering program design is the simplest, most easily understood, and most preferred by customers due to its simplicity and financial incentive. Some Michigan utilities, however – notably Consumers Energy and Detroit Edison –, have expressed fervent concern about the basic elements of this proposal. They believe this approach raises serious problems with respect to both cost recovery and possible intra-class cross subsidization (that is, subsidies from non-net metering customers paid to net metering customers). These issues are discussed in detail at p. 27.

Staff August 2007 Net Metering Proposal

While working with Consumers Energy and Detroit Edison over the summer and reviewing their proposals for implementing the March 2007 Staff Net Metering Proposal, both utilities were comfortable with charging customers a monthly fixed distribution charge, based on the customer's previous usage. For example, a residential customer who averaged 750 kWh per month over the last 12 months would pay a monthly charge equal to 750 kWh multiplied by Consumers Energy's or Detroit Edison's distribution charge found on that utility's residential tariff. This monthly charge was estimated at approximately $20 for Consumers Energy and $36 for Detroit Edison. With this information in mind and also knowing that both utilities have cost recovery concerns with meters spinning backwards, Staff developed its August 2007 proposal as a compromise.

Box 2:
Summary of Staff's August 2007 Net Metering Proposal

- **Use a single bi-directional meter to measure and record the following quantities: (1) electricity delivered from the utility (kWh); and (2) electricity delivered to the grid by the customer (kWh).**
- **Bill the customer based on their rate schedule for electricity delivered from the utility.** This part of the bill will not be based on "net" energy usage. Instead, the customer will be billed in the identical manner as a non-net-metering customer, for all electricity delivered by the utility.
- **Provide a net metering credit** on the bill, equal to the utility's retail generation rate (Retail Rate less distribution charge) for electricity, including all power supply charges and surcharges. Staff expects this will be a credit expressed as a dollar amount for the month. The bill should show kWh delivered, monthly power supply charge credit per kWh, and total $ amount.
- **Apply the net metering credit toward the customer's bill total.** Net metering credit can be applied to bring the bill down as low as the minimum bill. Any excess credit will be carried over month to month.

  At the end of each year, the utility would either: (1) give the customer a check for the amount of any unused net metering credits; or (2) continue to allow net metering credits to accumulate. MPSC Staff proposes checks might not be written for any amount less than $50, for example.

  The utility may treat net metering credits as a recoverable power supply cost.
- The utility may choose to calculate the distribution and surcharges the customer would have paid, based on their previous year's usage, absent net metering, but this is done as part of utility accounting for the purpose of making a request to the Commission for future cost recovery and not shown on the customer's bill.

Customer bills will have a normal billing section for the electricity delivered by the utility and then the following extra lines:

- Carryover net metering credit from past months (in $).
- Current month net metering credit based on current month electricity deliveries to the utility (in $). This is the kWh of electricity generated by the customer and delivered to the utility, multiplied by the total power supply charges. (Staff prefers this line item will also indicate the number of kWh and amount of credit per kWh. The per kWh credit is expected to vary each month, along with changes in the utility's PSCR factor.)
- Total net metering credit applied to this month's bill.
- Net metering credit carried over to the next month.
- Minimum bill/monthly customer charge
- Total bill due

The Staff proposal included a bi-directional meter capable of recording both inflow and outflow quantities, since it appeared that consensus could not be reached on allowing the customer's existing meter to spin backwards. The meter would measure the quantity of electricity delivered by the utility and the quantity of electricity the customer exported to the grid. The customer would continue to pay for electricity deliveries from the utility based on their current retail rate schedule. Net metering customers would receive a credit equal to the current month's generation portion of the retail rate, in dollars and cents, for every kWh exported to the grid. Currently, this amount is approximately equal to $0.054 plus PSCR and surcharges for Consumers Energy and $0.045 plus PSCR and surcharges for Detroit Edison. This dollar amount credit would be applied to the current month's bill. The customer would always pay at least the minimum monthly charge for a customer on their specific electric service tariff. Additional remaining credit, if any, would be carried forward to the next month.

This type of net metering program is a compromise between the simplest form of net metering used by Xcel Energy and We Energies and the Billing Method 1 based on total customer site usage used by Consumers Energy and Detroit Edison. The customer is not billed on their net usage like Xcel Energy and We Energies program, which would give a credit equal to the full retail electricity rate. The net metering incentive to the customer under the Staff's program is actually very similar to the current Billing Method 1 used by Consumers Energy and Detroit Edison. The financial difference between Billing Method 1 and the Staff proposal is that monthly net excess generation is immediately converted to a dollar amount and carried as a credit on the customer's bill to the end of the net metering year. Another difference is the treatment of this credit at the end of the year. Under the Staff's program, this credit is considered a power supply cost and at the end of the year, the utility will issue a check to the customer for any remaining credit or roll the credit over to the next year. However, during every month, the net metering customer would pay at least the minimum charge or monthly customer charge as a distribution contribution.

The simplification between Billing Method 1 and the Staff proposal is that only one bi-directional meter is used and customer bills are based on the actual quantity of electricity delivered by the utility and a credit is given for customer generation exported to the grid. Instead of the complicated customer site usage calculation, the utility may estimate lost distribution revenues in a similar fashion to what Consumers Energy and Detroit Edison proposed in response to Staff's draft May 2007 net metering proposal (e.g., valuing lost distribution revenues at 1/12 of the customer's previous 12 months distribution payments). Staff is proposing that the retail generation rate paid for the customer's generation that is exported to the grid be considered a power supply cost and fully recoverable by the utility. However, using a bi-directional meter will allow the utility to track the difference between the retail generation rate paid to net metering customers for generation exported to the grid and its avoided cost rate, if desired.

Comments Received on the Staff August 2007 Proposal

Nineteen sets of comments were received on the Staff August 2007 proposal. A complete set of comments is included in Appendix 1. There is still much concern about the cost of upgrading to a bi-directional meter. Net metering customers, installers and advocacy groups urge Staff to propose using the current meter and allowing it to spin backwards. They strongly recommend valuing the customer's on-site generation at the full retail rate and not just the generation portion of the retail rate.

Consumers Energy and Detroit Edison express two major concerns. One is that not being able to determine a customer's actual site usage could possibly prevent a utility from seeking cost recovery, in a future rate case, for what those companies could allege to be lost distribution revenues. Alternatively, the utilities raise the concern that, in a future rate case, non-net metering customers could conceivably have to make up for lost distribution revenues, thereby subsidizing net metering customers by paying slightly higher distribution costs. Similar to the analysis of the value of directly metering a customer's on-site generation for the purpose of determining potential renewable energy certificate (REC) sales, Staff does not agree with the utility's assessment of this risk. Staff believes any solution to this concern must eventually be grounded by a Commission determination on fundamental principles regarding cost causation and ratemaking treatment. Staff expects that engineering estimates of generator output, for 10 kW and smaller generators, will provide sufficient accuracy for any required analysis of what the utilities might characterize as lost distribution revenues.

Summary of Net Metering Issues

Metering Costs

Almost all Michigan net metering tariffs require the net metering customer to pay for meters used for net metering. Depending on the billing method chosen by a customer's utility, meters other than the customer's current meter are usually required. Meters and billing methods are discussed above. Based on net metering inquiries and/or complaints received by the Staff, these metering costs can be as high as $450 to $600. These amounts represent charges from the utility for meters, including installation. In some Michigan utility programs, the customer also faces charges associated with the placement and wiring of meter sockets, ready to accept a second (outflow) and sometimes a third meter (generation). One commenter said the extra cost of routing an additional meter socket to the exterior of his home has been approximately $400 in materials and $600 in labor. Some customers who otherwise would qualify for net metering have thus far opted not to participate in the program due to these metering charges.

In the foreseeable future, both Consumers Energy and Detroit Edison are planning to install upgraded, digital, "smart meters" for every residential customer. According to Detroit Edison, the new meters will be capable of functioning as bi-directional meters. It is expected that the new meters chosen by Consumers Energy will also have this capability. Because both utilities are planning to commence "smart meter" programs, meter upgrade costs should be minimized. Any relevant rate making issues can be addressed in the utility's rate case. The new meters are likely to be capable of recording additional data that will be helpful for net metering program evaluation, too, such as time of use and time of excess generation delivery to the electric grid.

It should be understood, however, that the meter capabilities alone will not necessarily ensure that net metering can be accommodated at no incremental charges to the net metering customer. In addition to the meters themselves, the utility automatic metering infrastructure (AMI) will have to be capable of interrogating the meters, obtaining required readings, and translating those readings into billing determinants. One net-metering customer of a cooperative utility, for example, was charged $650 for an AMI meter that could automatically record and report both inflow and outflow.

During the investigation, Detroit Edison proposed to eliminate the meter charge for all net metering customers regardless of size. Detroit Edison does not require customers with on-site generation that purchase standby service and sell excess energy to the utility to pay for their inflow, outflow, or generator meters.

Reverse Registration of Meters

The consensus agreement does not require that utilities offer customers the option to allow the meter to reverse register (that is, to spin backward). However, some utilities prefer this type of net metering system.

A rule change to the current MPSC Rule 480.3605 is presently being sought, to allow meters to reverse register when used in a Commission-approved net metering program. This rule change has already received approval from both MPSC Staff and representatives of Michigan utilities. R480.3605 presently reads as follows:

> R 460.3605 Metering electrical quantities.
> (3) Metering facilities located at any point where energy may flow in either direction and where the quantities measured are used for billing purposes shall consist of meters equipped with ratchets or other devices to prevent reverse registration and shall be so connected as to separately meter the energy flow in each direction.

The proposed language is:

> Metering facilities located at any point where energy may flow in either direction and where the quantities measured are used for billing purposes shall consist of meters equipped with ratchets or other devices to prevent reverse registration and shall be so connected as to separately meter the energy flow in each direction, unless used to implement a utility tariff approved by the Commission for service provided under a net metering program .

Rates and Incentives

The Commission noted in the May 29, 2005 Order approving the consensus agreement that the most successful net metering programs in other states offer the most customer incentives. During the Commission’s interconnection investigation in Case No. U-15113, many members of the public said they want to receive more than the utility's retail price of generation as a net metering credit. They point out that a higher price is fair compensation for net metering customers because renewable energy generators are providing clean power on the utility's distribution system without incurring transmission line losses that inevitably occur when power is generated at a central station coal or nuclear plant. Additionally, they point out that solar photovoltaic installations will be generating electricity during times of peak electricity demand, when the value to the utility is typically highest. On the other hand, this power is variable, and cannot be scheduled in advance, and the quantity provided by any one net metering customer is extremely small, compared to a utility's total load. The Commission Order discusses the incentive situation:

> "Although not as significant as some state programs, an incentive is offered in the consensus agreement in the form of the mechanism of net metering itself, which provides net metering customers a built-in buyer for the excess power that they generate without incurring transmission or distribution costs, and obviates the need for any storage capacity to be purchased or maintained by the net metering customer." May 29, 2005 Order, p. 6

Staff notes that the current Michigan program provides some incentive to net metering customers by using the full retail power supply charge (retail generation rate) as a credit for NEG. Without extensive calculations of the specific time periods when NEG is delivered to the grid, however, it is not possible to determine the utility's exact avoided cost for the energy delivered by a specific net metered customer or net metering customers in general.[32]

Currently, for most of the billing methods, the kWh charge for electricity from the utility is not equal to the kWh credit for customer generation going out on the grid. This difference is due to the distribution component of the kWh charge, because net generation provided by these net metering facilities does not eliminate the need for the investment in distribution equipment made by the utility in order to serve the customer. Using two different kWh rates, however – one for customer usage and another for NEG credits – necessitates the use of quite complex metering and billing protocols. The consensus agreement does provide, though, for the application of a fixed monthly charge to provide compensation for fixed distribution costs. This method is described above as billing method 4. Under this billing method, the customer's monthly fixed distribution costs would be separated from their charges for variable energy use. This sets the kWh charge roughly equal to the generation portion of the retail rate. When the kWh charge is equal to the kWh net metering credit, simplified and less costly metering can be used to bill the customer. Staff believes that customer satisfaction with net metering will increase when the kWh net metering credit is equal to the kWh charge for electricity.[33]

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[32] The MREP Solar Committee is working with volunteers from the Great Lakes Renewable Energy Association to complete a sample analysis of the expected time and value of solar electricity production, for representative solar photovoltaic systems interconnected and operating in net metering fashion. That report will be made public as soon as it is completed.

[33] A phone survey about net metering programs was conducted by contacting state regulatory commissions in the region. Indiana and Wisconsin utilities generally use one meter that reverse registers when customers export electric generation to the utility grid.

Treatment of Net Excess Generation (NEG)

Under Michigan's present net metering program, at the end of each 12-billing-month cycle, cumulative NEG credits, if any, are retained by the utility and the customer's credit is reset to zero. A utility may voluntarily propose a program where customers are awarded a cash payment for NEG. No cumulative NEG credits were reported for any net metering customer for the last net metering year for which data has been compiled, ending June 2006.[34]

Granting NEG credits to the utility is an incentive to the customer to size the generator not to exceed their self-service needs. Under the current consensus agreement, the value of the NEG credits retained by the utility is intended to be used to offset costs associated with the utility's operation of the net metering program.

Both Consumers Energy and Detroit Edison have offered to give net metering customers the option of selecting the starting month for the 12-billing-month cycle. This will give customers the best opportunity to use up their NEG. For example, a solar installation would produce the most NEG during the summer months. Starting the 12-billing-month cycle at the beginning of the summer would give customers the entire fall, winter and spring to use up any NEG. A wind installation in Michigan might be expected to produce most of its annual generation during the winter months. Therefore, starting the 12-billing-month cycle in the fall would give wind generating net metering customers the best opportunity to fully recover their NEG.

The August 2007 Staff net metering proposal provides for utilities to pay net metering customers for NEG at the retail generation rate. This provides a small financial incentive to net metering customers. Staff believes these NEG quantities will be small for most customers, and that this incentive will not have a noticeable impact on customer rates. Table 2 lists avoided cost rates for Consumers Energy and Detroit Edison.

Utility Rate Recovery

There is a concern that under a simplified net metering program, participants would not make a fair contribution towards the utility's distribution costs; especially fixed distribution costs. The foundation of the consensus agreement is that each utility will be allowed to recover from its customers all costs associated with its net metering program. However, accurately calculating these costs requires recording quantities of utility deliveries to the customer, customer deliveries to the utility, and the quantity of customer generation used by the customer (unless the customer makes a fixed distribution payment each month). The quantity of the customer's generation used on-site by the customer is used by Consumers Energy and Detroit Edison to calculate lost distribution revenues due to net metering.

Utility distribution costs are not noticeably reduced as a result of customer owned generation, at least while the total number of self-generating customers and their deliveries of excess energy to the grid are both small. On the contrary, utilities will likely incur significant added distribution costs associated with developing their systems so that they will be capable of routinely managing

[34] The consensus agreement directs utilities to file annual net metering reports by September 30 of each year for the year ending June 30. These reports are electronically filed in the U-14346 docket. Data and analysis of these reports will be reported to the Commission in the 2007 MREP Net Metering Report.

growing quantities of distributed electricity generation.[35] Therefore, some utilities contend net-metering customers should not be entitled to any credit for distribution costs. When a customer uses electricity they generate, the utility must be standing by, ready to supply the customer's full electricity needs. One utility commented that customers are not entitled to standby service without compensating the utility for the cost of providing standby service. If the net metering customer does not pay their fair share of utility distribution costs, then other customers will have to pay more, to make up the difference. It is this possibility that raises the concern about subsidies from one customer group to another.

However, residential tariffs for both Consumers Energy and Detroit Edison do not presently require customers to make any specific minimum distribution contribution, beyond the minimum monthly payments. Residential customers who reduce their usage through employing conservation or energy efficiency measures are currently not required to make any specific distribution contribution, beyond monthly minimum charges (currently, approximately $5 per month for Consumers Energy and Detroit Edison residential customers). Consumers Energy and Detroit Edison are the only regulated Michigan utilities without monthly customer charges in their residential service tariffs. However, this issue is expected to be addressed in both utility's current rate cases.[36]

Paying customers the retail generation rate or the full electric retail rate is above the market rate the utility pays for electricity. Consumers Energy and Detroit Edison already have avoided cost rates set by the Commission that apply to the purchase of renewable energy.[37] These rates for recent months are shown in Table 2. Utilities are concerned that if they pay net metering customers more than avoided cost rates for their electricity and that cost is recovered from other rate payers, then rate payers are paying more than is reasonable for electric supply.

Net metered generation is not valued as highly as dispatchable utility generation by utility supply planners because they can not count on a known quantity of generation being available at a certain time. The argument has been made that solar generated electricity will be valuable to the utility. The logic is that solar electric output in Michigan corresponds to the same days and times

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[35] For a thorough examination of the potential benefits associated with distributed generation, see Lovins, A. B., Kyle Datta, Thomas Feiler, Karl R. Rábago, Joel N. Swisher PE, André Lehmann, and Ken Wicker <continued> <continued> (2002); *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*; Snowmass, CO: Rocky Mountain Institute; http://www.smallisprofitable.org.

[36] See Consumers Energy's current rate case filing in the electronic docket for Case No. U-15245 at http://efile.mpsc.cis.state.mi.us/efile/viewcase.php?casenum=15245; Consumers Energy's proposed residential fixed charge of $6.60 per month is discussed in http://efile.mpsc.cis.state.mi.us/efile/docs/15245/0002.pdf#209. See Detroit Edison's current rate case filing in the electronic docket for Case No. U-15244 at http://efile.mpsc.cis.state.mi.us/efile/viewcase.php?casenum=15244. The $5 estimated monthly minimum charge for residential customers of Consumers Energy and Detroit Edison is not a "customer charge" per se, but is based on minimum kWh use. For example, if a residential customer used enough kWh to generate a bill equal to or greater than $5, the minimum charge would not apply.

[37] See Consumers Energy's Rate CG rate schedule for more information on renewable energy purchase rates. Utility rate schedules are available at http://www.michigan.gov/mpsc/0,1607,7-159-16377-118910--,00.html. Avoided energy costs methodologies were developed in Case No. U-6798 for all utilities. For more information see the Commission's August 27, 1982 Order at http://www.cis.state.mi.us/mpsc/orders/archive/pdfs/U-6798_08-27-1982.PDF.

as peak electricity usage, when the electricity has above average value.[38] However, the opposite argument has been made for wind, since the times of peak wind generation are not expected to correspond with times of peak electricity demand; times when the value of electricity is below average. Each kWh of customer generation from a net metering customer that is sent out on the utility grid causes some other generation to be backed off in equal measure. The question to be addressed is whether a utility's average avoided cost rate for net metered electricity will be more or less than the company's average retail generation rate. The answer to this question could well depend on the ratio of solar to wind generation in the net metering program.

Table 2: Consumers Energy and Detroit Edison Average Monthly On- and Off-Peak Avoided Cost Rates (July 2006 – June 2007)

	Consumers Energy1		Detroit Edison2	
	On–Peak $/kWh	Off-Peak $/kWh	Off-Peak $/kWh	Off-Peak $/kWh
July 2006	0.0479	0.0296	0.0658	0.0420
August 2006	0.0481	0.0298	0.0691	0.0371
September 2006	0.0489	0.0317	0.0336	0.0261
October 2006	0.0536	0.0328	0.0327	0.0244
November 2006	0.0512	0.0315	0.04231	0.029529
December 2006	0.0485	0.0280	0.033278	0.023606
January 2007	0.0463	0.0275	0.032522	0.021581
February 2007	0.0517	0.0292	0.044162	0.02573
March 2007	0.0515	0.0300	0.051897	0.033237
April 2007	0.0565	0.0332	0.026575	0.021293
May 2007	0.0593	0.0353	0.079315	0.037444
June 2007	0.0636	0.0359	0.041506	0.024927

[1] Data is for purchase rate CG. This rate is the energy-only purchase price to be paid for the purchase of energy from qualifying generating installations of 100 kW or less. Consumers Energy's rate is calculated using the running average for the previous three months.
[2] Average marginal cost for cogenerators (avoided energy cost from Case No. U-6798). Detroit Edison's rate is calculated from the average for the present month.

This data is provided for informational purposes only. Actual rates applicable to specific customers vary according to MPSC approved tariff rules and actual utility avoided costs each hour.

An issue to consider here is whether it is reasonable for this group of inverter-based 10 kW and under net metering customers to make a distribution contribution equal to either: (a) the same amount as prior to the installation of on-site generation; or (b) some other amount. Particularly if obtaining all data necessary to precisely assign distribution charges will require either a bi-directional meter or 2 or 3 standard meters, the concern for accuracy in assigning distribution charges has led to increased costs and complicated customer bills for net metering customers.

[38] As discussed in footnote 32 (p. 3), some research is already underway to help answer this question.

Mr. Joshua Barclay, a Detroit Edison residential customer with a 3.2 kW freestanding, solar tracking photovoltaic system, provided data on the total monthly quantity of electricity generated in kWh. He noted that his since his system is solar tracking it would likely produce more energy than a roof-mounted or non-solar tracking system. To provide some background on the amount of kWh produced by this type of renewable energy generator, data is presented in Table 3. The typical utility customer usage averages between 600 and 800 kWh each month.

Table 3: 3.2 kW Solar Tracking PV System, Monthly kWh Generation

Month	Energy Generated by PV array (kWh)
September-06	292
October-06	362
November-06	236
December-06	212
January-07	191
February-07	391
March-07	528
April-07	517
May-07	698
June-07	753
July-07	691
August-07	561
Total	**5,433**

Net metering program design and billing methods used by some Michigan utilities and in particular, Consumers Energy and Detroit Edison, can be considered unreasonably complex for these smaller net metering customers. In Staff's opinion, they are. The Commission has clearly envisioned the possibility of different net metering tariffs for smaller net metering installations. In the March 29, 2005 Order approving the amended consensus agreement, the Commission encouraged utilities to consider offering one set of net metering tariff rules for systems up to 5 kW and wind generators up to 25 kW, with different net metering rules applicable to larger systems (p. 4 of consensus agreement).

Consumers Energy and Detroit Edison had no net metering customers as of June 2006 when the most recent utility net metering reports were last filed, on September 30, 2006. The net metering program has been available for customers since the fall of 2005. The next set of utility net metering reports is being filed by September 30, 2007 for the period ending June 30, 2007.

Simplified Approach to Net Metering

Conclusion

The utilities point out that the consensus agreement provides for the net metering program to run through 2009. They request letting the program continue its course until then. After the fourth year of the net metering program, the consensus agreement directs MREP Staff to prepare an evaluation report with recommendations about the continuation and any proposed alterations of the program. During this interconnection investigation, Staff has become aware that there is significant dissatisfaction with the net metering program as it is currently being offered by some utilities.

Staff also understands that legislative activity on net metering might address net metering issues. Net metering is the subject of proposed HB 5121, which lists Representative Paul Opsommer as the primary sponsor, with eight co-sponsors. Purchasing arrangements for renewable energy generation, including small generators, are also among the elements included in HB 5218, the Michigan Renewable Energy Sources Act, recently introduced by Representative Kathleen Law.

The participants in this collaborative effort have been unable to reach a consensus on a simplified net metering program.

Obtaining accurate data for cost recovery of lost distribution revenues and the difference between the retail generation rate and avoided cost, as Michigan's two largest electric utilities have proposed, can require both complex billing and calculation methods. As Staff notes, however, a plausible alternative is the use of analysis based on readily available utility data and generally accepted engineering estimates.[39] The metering required to do this can be expensive for the customer. However, the added net metering program complexity and metering costs to the net metering customer must be weighed against the benefit of obtaining this data, especially for 10 kW and under inverter-based net metering customers. Also, the numbers of customers currently participating and expected to participate in net metering programs should also be considered. For the time being, customer-sited wind and solar generators designed to serve individual customers are expensive and the high cost can be expected to keep the numbers of net metering customers small. It should also be emphasized that without additional explicit Commission approval, the current net metering program will not be expanded beyond 0.1% of a utility's peak load or 100 kW (whichever is larger).[40]

Uncertainty with regard to expected changes in utility net metering programs is causing some customers to delay their renewable energy generation projects or at least delay applying for net metering treatment.[41] Staff is aware that customers, dealers, and installers alike are all awaiting some form of immediate relief through the process initiated for Case No. U-15113.

[39] See footnote 30 on p. 19, and the discussions about the use of engineering estimates on p. 24, and Utility Rate Recovery beginning on p. 27.

[40] As it now stands, the Michigan net metering program specifies that any utility seeking an alternative maximum program limit, either higher or lower, shall request and obtain Commission approval. Consensus Agreement, p. 5

[41] A customer with a qualifying renewable energy generator may complete an interconnection with the utility company while having their inverter set so that electricity can not be exported to the grid.

Staff recommends that the Commission continue working toward revising the administrative rule that prohibits reverse registration of meters (R 460.3605).

Since the workgroup did not reach a consensus, for the Commission's consideration, Staff proposes that utilities offer, at least to all net metering customers with 10 kW and under inverter-based systems, the net metering program shown in **Box 2**. This provides a simplified approach to net metering and is a compromise between the true net metering program sought by net metering advocates and the complex programs offered by Consumers Energy and Detroit Edison. The Staff proposal requires only one meter. Because both utilities are planning to commence AMI programs, meter upgrade costs should be minimized. Any relevant rate making issues can be addressed in the utility's rate case.

The cost some utilities are charging customers for the inspection and testing of net metering installations will be considered during the 10 kW and under rulemaking process. Staff is recommending interconnection rules very similar to the Wisconsin Rules, which do not allow utilities to charge customers for performing anti-islanding tests or verifying the protective equipment settings. Incorporating this recommendation for Michigan will require changes to be made through a rulemaking process, though.

Staff's net metering recommendation should not prevent utilities from offering a true net metering program. Utilities currently offering this type of net metering program may continue these offerings and the remaining utilities are encouraged to give serious consideration to adding this option to current net metering offerings.

Utilities with cost recovery issues should propose a plan for rate recovery in a rate case. If the Commission agrees with the Staff's recommendation, utilities should be directed to file revised net metering tariffs.

Interconnection Procedures

History of Interconnection[42]

Public Act 141 of 2000[43] directed the MPSC to establish interconnection standards for the interconnection of merchant plants with the transmission and distribution systems of electric utilities. Public Act 141 does not explicitly require utilities to interconnect with generating facilities with a capacity of less than 100 kW; however, the Commission encouraged development of interconnection standards which include smaller systems.

The Commission issued a June 19, 2000 Order in Case No. U-12485 directing the Staff to consult with electric utilities operating in Michigan, owners and operators of merchant plants and proposed merchant plants in Michigan, and other relevant stakeholders to develop

[42] Staff *History of Interconnection* document is available at http://www.dleg.state.mi.us/mpsc/electric/capacity/energyplan/alttech/mi_interconnection_stds01.pdf
[43] PA 141 of 2000, Section 10e(3) (MCL 460.10e(3); http://legislature.mi.gov/doc.aspx?mcl-460-10e.

recommendations for the standards.[44] Further Orders and Staff reports on this matter are available in the electronic docket for Case No. U-12485.[45] Electric Interconnection Standards (Michigan Rules) were developed and on March 26, 2003 the Commission established Case No. U-13745 as a formal rulemaking proceeding.[46]

The Commission formally adopted the Michigan Rules on September 11, 2003. The Michigan Rules can only be changed in a formal rulemaking proceeding. Rule 2 directed each utility to file proposed interconnection procedures for approval. Michigan utilities made efforts to develop a uniform set of interconnection procedures. For administrative efficiency Northern States Power Company (d/b/a Xcel Energy) and Indiana Michigan Power Company (d/b/a American Electric Power) filed interconnection procedures that were consistent with procedures adopted in other states, where a majority of their customers reside. The remaining sixteen Michigan regulated utilities adopted a uniform set of interconnection procedures.

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Interconnection procedures for all regulated utilities were approved by Commission Order on August 10, 2004 in the following cases:

Case No. U-14085[47]
Northern States Power Company (Xcel Energy)

Case No. U-14088[48]
Alpena Power Company, Consumers Energy Company, The Detroit Edison Company, Edison Sault Electric Company, Upper Peninsula Power Company, Wisconsin Electric Power Company, d/b/a We Energies, Wisconsin Public Service Corporation, Alger Delta Cooperative Electric Association, Cherryland Electric Cooperative, Cloverland Electric Cooperative, Great Lakes Energy Cooperative, Tri-County Electric Cooperative, Midwest Energy Cooperative, The Ontonagon County Rural Electrification Association, Presque Isle Electric & Gas Co-op, and Thumb Electric Cooperative of Michigan.

Case No. U-14091[49]
Indiana Michigan Power Company (American Electric Power)

This report focuses on the interconnection procedures approved in U-14088 that are applicable to all but Xcel Energy and American Electric Power.

Michigan's interconnection standards and procedures have 5 size categories:

- under 30 kW,
- 30 kW or more but less than 150 kW,
- 150 kW or more but less than 750 kW,

[44] See Order at: http://efile.mpsc.cis.state.mi.us/efile/docs/12485/0001.pdf.
[45] See http://efile.mpsc.cis.state.mi.us/efile/viewcase.php?casenum=12485.
[46] See http://efile.mpsc.cis.state.mi.us/efile/viewcase.php?casenum=13745. See the Michigan Rules at http://www.state.mi.us/orr/emi/admincode.asp?AdminCode=Single&Admin_Num=46000481&Dpt=LG&RngHigh.
[47] See http://efile.mpsc.cis.state.mi.us/efile/viewcase.php?casenum=14085.
[48] See http://efile.mpsc.cis.state.mi.us/efile/viewcase.php?casenum=14088.
[49] See http://efile.mpsc.cis.state.mi.us/efile/viewcase.php?casenum=14091

- 750 kW or more but less than 2 MW, and
- 2 MW or more.

Generator Sizes for Recently Completed Utility Interconnections in Michigan

As part of this interconnection investigation, the Commission directed each regulated utility to provide a listing of completed interconnections processed under the new interconnection procedures by November 28, 2006. Information on the timing of each step in the process and any problems encountered was also requested. Table 4 shows the data summarized by generator size. The February 27 Order requires utilities to file every 6 months interconnection reports listing pending and completed interconnection projects. The first set of reports is due by September 30, 2007.

Table 4: Summary of Michigan Interconnections by Utility for Projects Completed or Pending by Size (in kW), November 28, 2006

Regulated Utility	Number of Completed or Pending Projects	10 kW and under	>10 kW to under 30 kW	30 kW to under 150 kW	150 kW to under 750 kW	750 kW to under 2 MW	2 MW and greater
Alger Delta Co-op	1	1					
Alpena Power	2	1	1				
American Electric (Indiana Michigan) Power Co.	0						
Cherryland Electric Co-op	0						
Cloverland Electric Co-op	1	1					
Consumers Energy	22	6			2	9	5
Detroit Edison	21[1]	7[1]			1[1]		
Edison Sault	0						
Great Lakes Energy Co-op	1		1				
Midwest Energy Co-op	0						
Ontonagon County REA	2[2]	2[2]					
Presque Isle Electric & Gas Co-op	0						
Thumb Electric Co-op	0						
Tri-County Electric Co-op	0						
Upper Peninsula Power Co.	3	1			1		1
We Energies[6]	2	1				1	
Wisconsin Public Service Corp.	0						
Xcel Energy	0						
Total	55	20	2	0	3	10	6

[1]The Detroit Edison and Total rows do not add across the table because the generator size for Detroit Edison interconnections was not known for all applications. At least 7 interconnections are 10 kW and under and one is the Laker Schools three 65 kW wind turbines (195 kW total). The generator sizes for the remaining Detroit Edison interconnections are not known.

[2]Intalled pre-2004.

10 kW and Under Interconnection Procedures

The largest number of interconnections, nearly half as shown in Table 3, have been for generators 10 kW and under. A review of interconnection procedures applicable to other states indicates that 10 kW is a common size category for specific, simplified and streamlined interconnection procedures. Consensus was reached at the January 9, 2007 interconnection investigation public meeting on the idea of developing a separate set of faster and less complex interconnection procedures for 10 kW and under projects.

In the February 27 Order, the Commission directed the Engineering Section of the Commission's Operations and Wholesale Markets Division to establish a workgroup to develop faster and less complex interconnection procedures for 10 kW and under interconnection projects.

As a starting point for the workgroup, in March 2007, Staff issued a proposal with new interconnection procedures and revised Michigan Rules documents and requested comments. The proposed interconnection procedures were based on the language in the Interstate Renewable Energy Council's (IREC) model interconnection procedures applicable to inverter based interconnection projects sized 10 kW and less.

Seventeen parties filed comments on April 16, 2007. Most of those comments referred to the net metering proposal but several commenters addressed the Staff's proposal for interconnection procedures. The Staff's March 2007 proposal and complete set of comments is included in Appendix 2. The utilities raised numerous issues concerning the use of the IREC model interconnection procedures. Issues raised in other comments include utility acceptance of UL 1741 certification and the use of equipment manufactured prior to standards/revised standards becoming effective.

In the spring of 2007, Staff became aware that the National Renewable Energy Laboratory (NREL) has a program in place to provide assistance to state commissions in the process of developing or updating interconnection rules. Staff began working with Brad Johnson of ACN Energy Ventures (contractor to NREL). Mr. Johnson has extensive knowledge of interconnection issues due to his involvement in the ongoing Maryland interconnection rules development process. A public meeting was held on June 19, 2007 for the 30 kW and larger interconnecttion procedures workgroup and Mr. Johnson attended to help facilitate the discussion. Some of the issues discussed are applicable to 10 kW and under interconnections also. At this meeting Staff presented its strawman proposal for handling 30 kW and larger interconnection issues. Comments received on these issues indicated that the utilities would like to consider adopting interconnection rules that are very similar to those used in Wisconsin. Utility comments included a copy of Chapter PSC 119 Rules for Interconnecting Distributed Generation Facilities (Wisconsin Rules).[50] A 31-page document titled Wisconsin Distributed Generation Interconnection Guidelines (Wisconsin Guidelines) was developed in response to the Wisconsin Rules to provide guidance about the requirements for interconnection.[51] This section of the Staff

[50] See the Wisconsin Rules at http://www.legis.state.wi.us/rsb/code/psc/psc119.pdf.
[51] See the Wisconsin Guidelines at http://www.wisconsindr.org/library/PSC/WI_InterconnectionGuidelines.pdf.

report focuses on what the Wisconsin Rules refers to as Category 1; 20 kW and under. The Wisconsin Rules provide for a standardized interconnection application and interconnection agreement forms.[52] There are two sets of forms, one for Category 1 interconnections and then one set for all other Categories.

Staff prepared a comparison document comparing the key elements of the Wisconsin Rules to the current Michigan Rules. The comparison document in included in Appendix 2. Many of the issues presently affecting Michigan interconnections would be addressed by the Wisconsin Rules. An added benefit would be the administrative efficiencies our multi-state utilities with Wisconsin customers would be able to realize by using similar interconnection procedures for both states.

Wisconsin Rule Highlights for Interconnection Projects Sized 20 kW or less – Category 1

- Requires utilities to appoint a single point of contact for interconnection matters. Utilities must have current contact information on file with the Commission.
- Utilities use the same statewide application.
- Utilities use the same Interconnection & Operating Agreement.
- No application review fee.
- Simplified application: 3 page form with the following attachments: one-line diagram, site plan, certificate of insurance (applicant must have $300,000 in liability insurance), copy of proof of equipment certification.
- Utility shall notify applicant within 10 working days of receipt whether application is complete. (There is no requirement, like Michigan presently has, for utilities to acknowledge receipt of the application within 3 working days.)
- Utility has 10 days after the application is complete to complete its application review and determine if an Engineering Review is necessary.
- If an Engineering Review is necessary, it must be completed within 10 working days. The Engineering Review will determine whether a Distribution Study is necessary.
- If a Distribution Study is necessary, it must be done within 10 days.
- The interconnecting customer is not charged for an Engineering Review or Distribution Study.
- Applicant must pay for any distribution modification or upgrade costs.
- Utility may perform an anti-islanding test only.
- Applicant shall notify the utility in writing that the DG installation is complete and that it is available for testing at least 15 working days before applicant interconnects to distribution system. Utility may witness the applicant's test or perform its own test.
- Utility may not charge customer for performing an anti-islanding test or verifying the protective equipment settings.
- External disconnect switch may be required.
- Interconnected Category 1 generators must be operated at a power factor greater than 0.9.

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[52] See the Wisconsin Interconnection Applications and Agreements at http://psc.wi.gov/utilityinfo/electric/distributedGeneration/electricgenerationForms.htm.

Based on issues identified during the interconnection investigation, several additions to the Wisconsin Rules were included in the Staff proposal sent to the workgroup on August 22, 2007.

Proposed Additions to Wisconsin Rules

The proposed additions are generally applicable to larger sized interconnections and are discussed in the 30 kW and larger section of the report.

- Provide for a pre-application meeting between utility and project developer.

- Include a provision for the Commission to appoint expert(s) to provide technical expertise related to interconnection issues. This function would be similar to the provision in the Animal Contact Current Mitigation Rules or PA 30 Electric Transmission Line Certification Act. Excerpts from these MPSC Administrative Rules appear in Attachment E. In particular, this expert would provide assistance to the Commission, in the event there are any cost-related or technical issue complaints.

- Require distribution utilities to consult with the area's transmission owner(s) for all generator projects >2 MW and when total generation on a distribution line will exceed 10 MW.

Staff requested comments from the workgroup on the Wisconsin Rules and proposed additions by September 7, 2007. Two sets of comments were filed. Comments indicate there is support for using the Wisconsin Rules as a basis for Michigan's updated interconnection rules. Comments are included in Appendix 2.

UL 1741 Certification and the IEEE 1547 Standard

The UL 1741 standard covers inverters and interconnection system equipment intended to be operated in parallel with the utility. IEEE 1547 is the IEEE standard for interconnection of distributed resources with electric power systems. UL 1741 and IEEE 1547 are coordinated. For example, the anti-islanding test in Section 46.3 of UL 1741 was deleted effective May 7, 2007 and the new unintentional islanding test is located in IEEE 1547.1, Section 5.7.1.

During this interconnection investigation, one of the major issues raised was determining exactly how UL 1741 and IEEE 1547 standards should be incorporated into the interconnection process. The workgroup did not reach consensus on this issue. Non-utility commenters tell us that if an inverter is UL 1741 certified then the utility should allow interconnection with no further study and investigation.[53] During the interconnection investigation, utilities were asked if they would accept UL 1741 certified equipment. Several utilities commented that there can be situations where the UL certification, in and of itself, does not insure acceptability for interconnection.

[53] An inverter is an electrical device that changes direct current generated by a wind turbine or solar photovoltaic system, for example, into alternating current.

Staff is aware of two recent interconnection applications where a utility had concerns with interconnecting an inverter, even though it was UL certified. The specific issue for both interconnections was determining that the disconnect time of the inverter during a utility system fault was less than the utility's reclosing time on the circuit.[54] IEEE 1547 requires that the inverter cease to energize the area electric power system circuit to which it is connected prior to reclosure by the area electric power system. For these two interconnection projects, the utility insisted on seeing the test data to verify this information. In both instances, the utility was able to approve the interconnections after receiving the data, but only after significant delay. Unfortunately, the actual test data is reportedly considered confidential by both the testing laboratory and inverter manufacturer and there can be substantial delay while the utility works to obtain this data. However, once the utility has this data for a particular inverter, future interconnection applications for this inverter will not be held up due to this issue.

Staff does not believe that any rule change will resolve this issue. Even if an inverter is UL 1741 certified, if it does not safely respond to a variety of specified abnormal distribution system conditions, it violates IEEE 1547. However, a serious barrier to interconnections is raised if installers and developers cannot be sure a particular inverter make or model will be accepted by the utility.

This issue would not be resolved by adopting the Wisconsin Rules. They say the applicant may use certified paralleling equipment for interconnection to a distribution system without further review or testing of the equipment design by the public utility, but the use of this paralleling equipment does not automatically qualify the applicant to be interconnected to the distribution system at any particular location. The public utility may still require an engineering review to determine the compatibility of the distributed generation system with the distribution system capabilities at the selected point of common coupling. (Excerpt from PSC 119.26, Certified paralleling equipment).

As Staff understands this general issue regarding UL certification, however, there can be circumstances when it is possible that UL 1741 certification, in and of itself, is insufficient proof of full compliance with the IEEE 1547 standard. In those circumstances, Staff believes it is incumbent upon the utility to ascertain how the interconnection can be completed in a manner that meets the standard.

For UL 1741 certified equipment, Staff recommends that Michigan utilities be ready to complete installations with minimal delays. If a Michigan utility believes that a UL 1741 certified inverter

[54] A recloser is an automatic, high-voltage electric switch. Like a circuit breaker on household electric lines, it shuts off electric power when trouble occurs, such as a short circuit. Where a household circuit breaker remains shut off until it is manually reset, a recloser automatically tests the electrical line to determine whether the trouble has been removed. And, if the problem was only transient, the recloser automatically resets itself and restores electric power. See http://www.cooperpower.com/Library/Literature/R280908/ to read more about reclosers.

installed on its distribution system would fail to meet the IEEE 1547 standard, one approach that Staff would support is that the utility undertake actions to resolve that concern as follows:

> First, a utility determines which inverters are being considered for installation on its system. The utility can then analyze those inverters to learn whether there is any potential incompatibility between them and the utility's system.
>
> Second, if a possible incompatibility is discovered through this process, the utility identifies the system modifications to accommodate the UL 1741 certified inverter and establishes its process for completing such interconnections within the time allotted under the Michigan Rules.
>
> Third, the utility establishes regular communications with Michigan dealers and installers to make certain these first two steps are repeated, as necessary.

Staff expects these provisions can be accommodated quickly and with minimal expense.

<u>Engineering and Distribution Reviews</u>

The Wisconsin Rules do not specify what criteria would trigger an engineering or distribution review. The Michigan interconnection procedures for under 30 kW generator interconnection projects say that the utility will perform an Interconnection Study. However, the Project Developer is not required to pay Interconnection Study fees if the Project's aggregate export capacity meets certain criteria based on a calculation done by the utility using information about the distribution system at the interconnection location. The Interconnection Procedures say that it is typical for projects under 30 kW to not be required to pay Interconnection Study fees.

Wisconsin utilities have 10 days to complete their Application Review after the application is complete. If determined necessary by the utility, a Category 1 Engineering Review and Distribution Review can take up to 10 additional working days each. There is no charge to the applicant for these reviews and if the utility determines these additional reviews are necessary, the Wisconsin Rules require the utility to contact the applicant.

This Michigan Rules provide for the utility to have 2 weeks to complete all of its interconnection obligations after the application is complete. The Wisconsin Rules would give the utility more than two weeks if an Engineering or Distribution Review was undertaken. While increasing the time for utilities to complete the interconnection process may seem like a step backward, it does provide an interconnection process where applicants are aware that these studies may be done and sets clear time limits for the utilities. The utilities have commented that they have concerns with the timelines in the Michigan Rules, and in practice to date the Michigan timelines have frequently been exceeded. The Wisconsin process does require that the utilities notify the applicant before starting each review. Therefore, adopting the Wisconsin Rules means the applicant will know the status of the interconnection process at each step. Staff recommends adopting this combination of fixed time frames for the utility to complete the various studies and the ongoing maintenance of consistent communications between utility and applicant. Staff believes these proposed modifications will constitute a significant process improvement.

10 kW vs. 20 kW Generator Size Category

The Commission has directed the workgroup to develop faster and less complex interconnection procedures for 10 kW and under interconnection projects. The smallest size category in the Michigan Rules is for under 30 kW sized generators. Category 1 in the Wisconsin Rules is for interconnection projects sized 20 kW and less. Detroit Edison and Consumers Energy support continuation of the existing Michigan size categories. Utilities serving customers in both Wisconsin and Michigan prefer the Wisconsin size categories. A small generation owner commented that he prefers keeping the size category at under 30 kW. This is an issue that can be worked out during the rulemaking process. At this time, Staff does not have a preference on the size categories to be incorporated into revised Michigan Rules; however, Staff strongly recommends that the same size categories will apply to all Michigan utilities.

Liability Insurance and Indemnity Language

Currently, in Michigan, requirements for liability insurance and indemnity language are not standard across utilities. These requirements are generally included in each utility's interconnection and operating agreement. The Wisconsin Rules have very clear liability insurance requirements based on the size of the interconnecting generator. One commenter said that his homeowner's insurance, which covers his solar photovoltaic array, meets the Wisconsin Rule requirement of $300,000 in liability insurance. The utilities like that the Wisconsin Rules require the applicant to provide a certificate of insurance with the application and comment that the levels of coverage are acceptable to some. The utilities want to have the opportunity to consider alternatives to the Wisconsin indemnity language. Staff recommends following the provisions regarding liability insurance from the Wisconsin Rules, unless the evidence from the rule making proceeding indicates a revision is needed and Staff expects to support reasonable, fair indemnification language.

10 kW and Under Interconnection Procedures

Recommendations and Conclusions

Progress toward developing faster and less complex interconnection procedures is expected to continue. Comments received in August 2007 on adopting rules very similar to the Wisconsin Rules indicate there is support. Staff anticipates that the Michigan Rules will be completely replaced with a new set of rules and that a new set of interconnection procedures will also be developed to correspond with the new rules. The next step in this process will be assembling a draft set of new rules.

For UL 1741 certified equipment, Staff recommends that Michigan utilities be ready to complete installations with minimal delays. Staff suggests an approach whereby utilities would identify which inverters are being considered for future interconnections. Staff recommends that utilities analyze those inverters to learn whether there are any potential IEEE 1547 issues. If a possible IEEE 1547 issue is discovered through this process, the utility should identify the system modifications to accommodate the inverter and establish its process for completing such interconnections within the time allotted under the Michigan Rules.

30 kW and Larger Interconnection Procedures

The February 27 Order, directed the Engineering Section of the Commission's Operations and Wholesale Markets Division to convene a workgroup with these objectives:

1. Identify reasonable and achievable interconnection time deadlines.
2. Propose a system for determining whether interconnection costs are reasonable, actual costs.
3. Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections).
4. Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.
5. Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system.

During this interconnection investigation, issues affecting the 30 kW and larger interconnections were previously identified through written comments and discussions at public meetings. This report centers on moving toward resolving these issues by considering the above objectives with a focus on what can be done to improve the interconnection process. Details on interconnection problems and issues are discussed more fully in the January 31, 2007 *Staff Report on Utility Interconnection Issues*.[55]

APRIL 20, 2007 COMMENTS

The first task undertaken by this workgroup was to consider the five objectives above and comment on the best way to achieve them. These comments were due on April 20, 2007 and are included in Appendix 2. Four sets of comments were received. An additional interconnection issue was identified by interested parties and Staff regarding insurance requirements and liabilities.

[55] See the *Staff Report on Utility Interconnection Issues*, January 31, 2007 at http://efile.mpsc.cis.state.mi.us/efile/docs/15113/0047.pdf.

Time Deadlines

Utilities said that the time deadlines for projects 30 kW and larger are typically subject to site specific work requirements and other matters (right-of-way, equipment availability, labor, operating agreement, testing) that may not directly correlate with the project size categories used in the rules. Utilities may be able to stock some items of equipment with long lead times. Depending on the circumstances, they commented, time requirements could extend out to six months or more.

The utilities attached a copy of the Wisconsin Rules for informational purposes.

Cost Issues

One commenter said that extensive, costly, and time-consuming interconnection studies aren't done when the customer is a user rather than a generator. Several commenters suggested that utility grade relays are too expensive and that industrial grade relays should be sufficient. The cost of metering is another issue raised by one commenter. He further explained that the utility charged $4000 for a set of meters of which they retained ownership. When his project failed and the contract was canceled, the meters were removed and no money was refunded.

The utilities commented that they already charge customers the actual cost of modifications for an interconnection project. They explained that the process involves billing based on scope of project for materials and labor in a manner similar to customer line extensions. They specified that use of utility overheads in this practice is consistent with approved MPSC accounting practices. Utilities said they are willing to provide actual detailed cost breakdowns based on major components of the project such as the easement, materials and labor. They cautioned that customers are not permitted to perform work on utility assets.

Transmission Owner Notification Issue

ATC proposes two alternative threshold tests to determine when consultation with the transmission owner by the distribution utility should be required. Generators, especially in the lower range of the 30 kW and above class, would not trigger either of the tests.

The alternative threshold tests that ATC recommended are:

> Where a single generator request or the aggregation of existing and new generation, measured at the transmission-to-distribution point of interconnection, exceeds a) the minimum distribution load or, b) the total connected generation is 10 MVA or greater, transmission consultation should be required. (These are the two alternate tests.) In these cases some, but not most, interconnection requests will require detailed study.

In cases where more study is necessary, ATC said that the transmission owner should be able to provide a formal response to the distribution utility within 10-15 business days following receipt of certain basic generator-related information regarding the interconnection request.

ATC suggested that the Commission may want to consider whether the construction of transmission-related facilities that are required by virtue of distribution interconnection requires a further inquiry into how those costs are to be allocated among the interested parties.

The utilities said that many or even most generator projects connecting at the distribution level would not impact the transmission system or adjacent distribution system. If, however, the interconnection project is large enough to affect these other systems, the transmission owners should be consulted. The smaller projects (likely those under 2 MW) are less likely to impact other systems (although they could) and utilities suggest considering projects under 2 MW as a cutoff point for requiring the independent power producer to consult with the affected transmission or distribution system. Further, the utilities explained that each project is evaluated to determine the impact of capacity needs, flow back potential, effects on connected distribution systems, and upstream coordination in relation to the transmission system. Utilities will notify the transmission provider of potential impacts to the transmission system; however, the independent power producer should apply with the transmission provider as well as the utility, where appropriate (i.e. 2 MW or more). The MISO tariff governs the payment of cost of transmission system improvements by the project developer to the transmission provider.

Acceptable Power Factor

The utilities proposed that unity (1.0) power factor on the high side of the step up transformer should be the base requirement for all interconnected generator projects. They explain that this is consistent with recommendations contained in the document "Final Report on the August 14, 2003 Blackout in the U.S. and Canada: Causes and Recommendations" (April, 2004) prepared by the U.S. – Canada Power System Outage Task Force.

The standards could provide for mutual agreement on deviation from the base requirement and the utilities suggest that if a project deviates from the unity base, voltage regulation should be required for the system at the developer's cost. They explain that a low or high power factor appears as load on the system and could affect the function of existing regulators, capacitor banks, etc.

Identification of Areas of Opportunity on each Utility's Distribution System

The utilities recommend that the suitability of location might best be left to discussions at the pre-application meetings for a specific project. They say that general public identification of such areas may create concerns regarding security and terrorism and that for this reason, it is unwise to make too much knowledge of the utility system function available in a public manner.

The large size and dynamic nature of utility distribution systems makes this a difficult task. Changes to the system from storm damage, capacity planning and other modifications could alter the "areas of opportunity" over time, note the utilities. Utilities are concerned about possible liability claims based on performance of a project after selection of the optimal location. However, they do say there could be feedback in the discussions regarding the best choice among several locations presented by the developer for a project.

Insurance and Liability Issues

One commenter said that additional liability insurance can be dispensed with because there are no instances of linemen being injured due to a small power producer keeping the line energized. He further explained that protective relaying and lineman training make this a needless expense.

June 19, 2007 Staff Discussion Paper

Staff reviewed the comments and developed a Staff discussion paper that was presented at a workgroup meeting held on June 19, 2007.[56] The meeting also included presentation on power factor issues by Detroit Edison.

[56] See the Staff discussion paper at http://www.michigan.gov/documents/mpsc/MPSC_Staff_Discussion_Paper_for_30_kW_and_Larger_Interconn_206333_7.pdf.

MPSC Staff Strawman Proposals
for Improvements to Interconnection Procedures

DRAFT Document
for Discussion at June 19, 2007 Meeting of
30 kW & Larger Interconnection Procedures Workgroup

INTRODUCTION

MPSC Staff has reviewed all comments received to date. In the following strawman proposal, Staff has attempted to accommodate, as best as possible, all comments. Staff presents this strawman proposal with the intention of leading to a productive dialogue and consensus on as many aspects of the proposal as possible.

Staff has categorized all comments into the following major categories:

1. Timelines, and ideas for developing reasonable and achievable timelines;
2. Interconnection costs, and ideas for assuring project developers will pay reasonable and actual costs;
3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.; and,
4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.

In addition to those issues, Staff is researching:

5. Other miscellaneous issues raised in comments, but not covered in one of the previous four topic areas (including: insurance requirements and liabilities; pre-approved equipment lists; etc.); and
6. Possible power factor requirements for interconnected distributed generators.

Here are preliminary MPSC Staff recommendations for consideration. It should be noted that although the focus of this work group is on interconnections for systems 30 kW and larger, many of the concepts being discussed here could also be applicable to systems smaller than 30 kW.

As a matter of general perspective regarding the recommendations that will ultimately issue from this workgroup process, MPSC Staff has a preference for recommendations that can be adopted by consensus, and will improve the existing interconnection procedures to the extent possible, without having to await a new rulemaking proceeding to alter the existing rules. The Commission already noted, however, that some recommendations may require rulemaking, and established a new docket for that purpose, Case No. U-15239.[57] Thus, MPSC Staff has attempted in the following recommendations to identify whether it believes each recommendation does or does not require rules changes prior to implementation.

MPSC Staff invites review and comment on these recommendations, and will present this information for discussion at a June 19, 2007 meeting at MPSC Offices, Hearing Room A, scheduled for 10 a.m. to noon.

1. Timelines, and ideas for developing reasonable and achievable timelines:

   1.1 Developers or customers may request pre-application meetings with the utility. The pre-application meeting will allow the project developer and/or customer to seek preliminary guidance from the utility regarding engineering and design alternatives, including preferred locations for interconnection (see section 4 in this list, on page 48).

   1.2 Utilities will note the date when an application for interconnection is received, and the utility will notify the applicant within 3 business days, in writing, that the application has been received.

   1.3 Utilities will notify the applicant in writing within 10 business days of the date the application is received, if the application has been determined to be incomplete. If the application is determined to be incomplete, this notification will explain to the applicant what information is missing and will provide adequate direction to the application to allow them to correct any deficiencies in the application.

   1.4 In general, for the time being and until any changes in timelines are completed through a rulemaking procedure, MPSC Staff recommends that the currently adopted interconnection procedures timelines be utilized, with the utility response time tolled during periods when the project is delayed due to events that are outside of the utility's control. Tolling of the utility response time will, in all cases, require notification from the utility to the applicant, in writing, explaining: (a) the date further action on the interconnection process has been delayed; (b) the reason for delay; (c) the party whose action or inaction has resulted in the reason for delay; and (d) what is required to resolve the issue and re-start the interconnection process. When the issue is resolved, then the utility will again notify the applicant, in writing, of the date when the problem or issue has been resolved and the interconnection process continues.

   1.5 Utility companies could stock some equipment that will be commonly used in interconnections. Utilities should first develop lists of commonly used equipment, and work with suppliers to reduce the time required to obtain equipment when it is ordered. Then, to the extent that the costs of stocking equipment are reasonable and prudent, utilities should do so.

[57] February 27, 2007 Order in Cases Nos. U-15113 and U-15239, pp. 6, 7, 9, 10.

MPSC Staff believes action can be taken to implement recommendations 1.1 through 1.5, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

2. Interconnection costs, and ideas for assuring project developers will pay reasonable and actual costs

   2.1 Utilities will develop conceptual cost estimates for representative installations, based on generic interconnection parameters (subject to change based on actual circumstances for a specific project).

   2.2 Utilities shall maintain a list of qualified contractors as required by R 460.487(5).

   2.3 Utilities shall be required to obtain from qualified contractors three bids for the completion of interconnection work, and the customer shall be required to pay the amount associated with lowest of the three bids. The utility may utilize its own personnel to complete the interconnection work, but may not charge the customer more than the amount associated with the lowest of the three competitive bids.

MPSC Staff believes action can be taken to implement recommendations in 2.1 through 2.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

3. Consultations with transmission utilities, and ideas about who will be responsible for consulting with transmission utilities, under what circumstances, etc.

   3.1 Utilities should determine whether distribution level interconnections are likely to affect the transmission network. If effects on the transmission system are anticipated, then the utility should notify both the Midwest Independent System Operator (MISO) and the transmission owner (TO) of the interconnection request.

   Both MISO and the TO should be notified if the interconnected distributed generator: (a) is larger than 2 MW; or (b) will be capable of producing generation in excess of the minimum load on the distribution circuit. The utility shall notify the applicant, in writing, both that it has determined there is a need to notify MISO and the TO, and when the utility has completed that notification. Such notification to the three parties shall take place within not more than 10 days of the utility's receipt of a completed interconnection application.

   3.2 As part of the notification provided under item 3.1 above, the distribution utility should inform MISO and the TO of the distribution utility's study schedule and the date by which the distribution utility needs information from MISO and the TO, to coordinate studies and consider transmission impacts, if needed. Within the timeframe requested, it is expected that MISO and the TO will notify the distribution utility whether they will be a participant in the study or do not believe additional analysis of the transmission system impacts is warranted at that time.

3.3 The utility should request that MISO and the TO: (a) acknowledge receipt of the notification within not more than three business days; and (b) notify the utility of their interest in participating in system studies within not more than 10 business days.

MPSC Staff believes action can be taken to implement recommendations 3.1 through 3.3, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239. Staff notes that MPSC does not have regulatory authority over MISO or Michigan transmission owners, who are the subject of recommendation 3.2 and at least partly of recommendation 3.3. Staff understands that MISO and TOs are ready and willing to cooperate with this proposed procedure, and Staff seeks guidance from interested parties about this recommendation.

4. Identifying areas of opportunity for distribution system interconnections, where interconnection costs will be as low as possible and even where interconnection of distributed generation could reduce or avoid utility system costs.

4.1 MPSC Staff believes this recommendation must be considered for three different types of interconnection location decisions: (1) on or adjacent to the premises of a single customer; (2) within a small prescribed area defined by the applicant or system developer; and (3) within larger areas identified by the utility company. Whenever possible, the utility company should provide information suitable for decision making regarding (1) and (2) at or as soon as possible following a pre-application meeting with the applicant and/or developer. Information regarding the third type of location decision should be developed by the utility and made available to all interested parties, with updates no less frequent than every 24 months.

4.2 For type (1) decisions, the utility shall notify the customer of interconnection options and the likely costs associated with interconnecting at any reasonable point on or very near to the customer's premises.

4.3 For type (2) decisions, the applicant or system developer will be responsible for letting the utility know the general area where an interconnection is proposed, and/or a choice of possible locations. For example, a project might be proposed for installation anywhere within an area that is a specific distance from a specified point on the utility network, or another project might be proposed for installation at any of several multiple properties all owned or controlled by one entity.

For both type (1) and (2) decisions, the utility shall determine whether system studies are required in order to determine specific information adequate to provide the applicant or developer with reasonably accurate information upon which an interconnection location decision can be made. If the utility determines that further study is required, then the utility should notify the applicant or developer of that fact, and provide a schedule for the completion of that study.

4.4 For type (3) decisions, the utility should develop a map that indicates locations that are most suitable for the interconnection of distributed generation and are most likely to minimize interconnection costs. MPSC Staff is aware of similar efforts at Pacific Gas & Electric (reported in Lovins, et al., 2002, *Small is Profitable*), Commonwealth Edison, and Consolidated Edison, 2006, DSM 'Load Relief' RFP).

MPSC Staff believes action can be taken to implement recommendations 4.1 through 4.4, prior to completing any formal revision of the interconnection rules. Formal revisions to the rules to accommodate these proposed recommendations will be developed as needed, for presentation in Case No. U-15239.

5. Other miscellaneous issues raised in comments

5.1 Liability insurance. Comment from one developer is that additional liability insurance is unnecessary. MPSC Staff notes that insurance provisions are not presently included in Michigan's interconnection rules, but the Commission did approve the interconnection procedures document which explains that insurance and liability will be among those subjects covered in the utility interconnection and operating agreement.

It would be imprudent for a generator not to have ample insurance coverage, but MPSC Staff does not believe the existing rules allow the utility company to require any specific coverage. Interconnection contracts may include a statement to the effect that the generator acknowledges and accepts their potential liability in the event of an accident, however.

MPSC Staff recommends that all interested parties review the Wisconsin PSC Chapter 119 Rules for Interconnecting Distributed Generation Facilities, part PSC 119.05, and consider whether the Wisconsin insurance and indemnification provisions should be applicable for Michigan, too. (See http://www.michigan.gov/documents/mpsc/30_and_Larger_April_20_Comments_194118_7.pdf, pp. 9-10.)

5.2 Streamlining engineering studies. Recommendation is that utilities should make a determination quickly, whether studies are needed. MPSC Staff supports this concept, and believes this goal can be met by incorporating the recommendations listed under 1 through 4, above.

5.3 Simplified one-line diagrams. Recommendation is that the one-line diagrams required by utilities are presently too complex and should allow for further simplification. MPSC Staff seeks further clarification on this issue, and invites interested parties to submit more specific information.

5.4 Standby rates. Recommendation is that standby rates are presently excessive and should be lowered. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this issue in utility rate cases or other appropriate venues. MPSC Staff notes it believes that MISO Midwest Market rates are now available to provide backup power to customers, as needed, in lieu of purchasing standby and backup service from the utility company.

5.5 Criteria/Standards for Grid Interface Equipment. Comments state that requiring utility grade equipment is unnecessary and that industrial grade relays should be sufficient. MPSC Staff believes that decisions about equipment specifications should be determined by the appropriate national or international standards. IEEE 1547 specifies the performance that an interconnected system must meet. For customer-purchased equipment, the requirement should be for the interconnected system to meet performance specifications – subject to utility verification through a witnessed test –, and the customer should have discretion regarding equipment grade.

Comments also recommend that interface equipment be standardized, insofar as that is possible. This issue is addressed in recommendations 1.5 and 2.1.

5.6 Payments/Ownership of Interface Equipment. Recommendation is that the customer should be compensated for the residual value of interconnection equipment, if any, if the customer has paid for the installation of equipment which later turns out not to be needed for that customer's installation (if the generator ceases operation, for example). MPSC Staff recommends that current accounting practices be reviewed in order to determine the practicality of implementing this type of recommendation.

5.7 Utility financial self-interest. Recommendation is to consider how financial incentives can be changed to make utility cooperation with interconnections to be in the financial interest of the utility. MPSC Staff notes this issue is beyond the scope of the interconnection procedures process being investigated in U-15113, and suggests that interested parties address this issue in utility rate cases or other appropriate venues.

6. Possible power factor requirements for interconnected distributed generators

MPSC Staff recommends Michigan apply the general standard that the power factor requirements for distributed generators should match the requirements for customer loads, for the rate under which the distributed generation customer is served. MPSC Staff recommends Michigan utilize this language from the recently approved Maryland interconnection standards:

Reactive Power

The Interconnection Customer shall design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the power factor range required by the [utility's] applicable tariff for a comparable load customer. [The utility] may also require the Interconnection Customer to follow a voltage or VAR schedule if such schedules are applicable to similarly situated generators in the control area on a comparable basis and have been approved by the Commission. The specific requirements for meeting a voltage or VAR schedule shall be clearly specified in Attachment 4. Under no circumstance shall these additional requirements for reactive power or voltage support exceed the normal operating capabilities of the Small Generator Facility.

Comments on the June 19, 2007 Staff Discussion Paper were due on July 6, 2007. Five parties filed comments totaling 42 pages. The complete set of comments is included in Appendix 2.

The utilities pointed out that although this work group process is addressing interconnection of projects sized at 30 kW and up, experience and the type of project developers participating in the process indicate that the focus is still on "smaller" projects, likely to be sized at 2 megawatts (MW) or less. Based on utility experience, the larger independent generator interconnections tend to be worked out on a project specific basis, without the need for Commission oversight or complaint resolution. They find that developers of larger projects are typically experienced entities and there are likely to be multiple Utility employees devoted to the project.

Time Deadlines

One commenter suggested that a one-page tracking sheet be developed and accompany every application. The commenter envisions the tracking sheet would contain the completion dates of the various interconnection steps, reasons for delays, and contact information for both the utility and the developer.

The utilities say that the rulemaking time deadlines are proving unworkable in practice and development of more reasonable time periods should not be deferred. Utilities suggest that the Commission consider the interconnection deadline approach used in Wisconsin's Rule 119. Rule 119 provides deadlines for steps of the project (engineering review, distribution study and final testing) for the project size categories.

The utilities point out that the remaining steps in the process involve the utility completing detailed design, engineering, procurement of equipment, right of way, and final construction. The details of these parts of the timeline are not in the Wisconsin rule and need to be addressed.

Utilities may be able to stock some commonly used equipment with long lead times in an attempt to help expedite the interconnection process. However, they point out that this practice could give rise to other issues, since there are costs associated with stocking commonly used equipment (~7-10% loadings) and the time of use is uncertain. Additionally, they say most project developers will likely view the carrying costs as unreasonable; alternatively, other customers may object to these costs being absorbed by the utility creating a subsidy. The utilities suggest that the decision to stock items should be left to individual utilities based on their own policies and experience and that the policy should be consistent with the stocking of equipment to assure reliable service for general utility customers.

The utilities responded that utility notification within 10 days of whether the application is complete is consistent with the existing interconnection procedures; however, actual experience indicates this time period is not sufficient to fully address an application particularly where there are multiple applications and interconnection processes under review by a single utility. For these larger units the utilities suggest a time period of 1 month for review and notification of missing information in the application. The utilities say this will provide an incentive for project developers to make sure the application is complete and in some cases, even a complete application may indicate a need for additional information concerning the project. The utilities suggest that if preliminary analysis shows such a need, the utility should advise the project developer and be allowed 2 months to respond. The utilities point out that the "pre-meeting" process will provide an initial opportunity for information exchange between the parties to mitigate delay.

Cost Issues

The current interconnection procedures also require that the utility provide a good faith cost estimate of the project cost immediately after the application is complete, without a study having been completed, and with a two hour consultation. The utilities say that such a cost estimate is nothing more than a guess and that providing a cost estimate at that stage in the process timeline is clearly an unreasonable requirement that should be eliminated.

The utilities say that this process should not assume project developers are being charged unreasonable or excessive costs. The utilities commented that generally, utilities provide the interconnection services at their cost, which includes standard overheads and additionally, utilities also provide expertise through their trained personnel and may provide the cost advantage of equipment purchased in bulk**.**

Regarding the Staff proposal to have utilities develop blanket conceptual cost estimates, a possible alternative, suggested by the utilities, would be to hold pre-application meetings, and develop preliminary cost estimates based on proposed sites.

The Staff recommended that the customer should be compensated for the residual value of interconnection equipment, if any, if the customer has paid for the installation of equipment which later turns out not to be needed for that customer's installation (if the generator ceases operation, for example). The utilities responded that there will be little or no residual value to the utility for interconnection-related equipment (such as transfer trip, monitoring device, etc). This equipment is needed solely for the customer's interconnection. Furthermore, rates are based upon the cost of service and a regulated rate of return. The utilities point out that distribution cost does not decrease because a customer's generating unit shuts down. Additionally, they say that providing compensation for residual value would shift cost from the customer that caused the cost to other customers that did not cause the cost.

Section 5.5 of the Staff's proposal relates to the grade, industrial or utility, of interconnection equipment. The utilities commented that they are held accountable to maintain certain levels of system reliability and therefore must be permitted to control the type of equipment on their electrical systems. They say that project developers may install protective relays of any grade (such as industrial grade or utility grade) in order to protect their own equipment.

Utility Consultation with Transmission Providers

ITC and METC say that the transmission company must be involved in the generation interconnection process from the initial consultation/pre-application meeting for all generator interconnections and that they should assess if the interconnection will affect the transmission system. They point out that transmission design and guidance is only performed by the transmission company so it is essential that transmission owners be involved in the initial stages of interconnection discussions.

ATC reiterated that in most distribution level interconnections, ATC can assess interconnection impacts concurrent with utility studies and that only in a few cases would additional study time be needed. Although the Commission Staff has proposed a 2 MW threshold as one part of their test, ATC believes that raising this threshold to a higher value, such as 10 MW, would serve both the interests of reliability and efficiency in the interconnection process.

Acceptable Power Factor

As one commenter pointed out, power factor correction is primarily an economic issue, as the technical factors for correcting generator output are well known and quantifiable. He explained that this fact is evident in the past filings of Detroit Edison and Consumers Energy, which contain penalties for poor power factor and incentives for desired power factor.

Regarding the treatment of power factor correction from generation connections, this commenter explained that one can review FERC Docket No. ER06-348-000, in which a generator in Michigan requested over $1.3MM per year in remuneration from MISO to provide power factor correction on the grid as per Schedule 2 of the MISO tariff. He notee that this generator was not expected to generate at unity power factor, and in fact expected to receive guaranteed payment for power factor support. The commenter explained that the above facts demonstrate that there is significant precedent in both financial penalty for undesirable power factors as well as financial incentive for desirable power factors.

The commenter recommended the following guidelines for the workgroup to consider:

- Any party seeking to assess penalties for undesirable power factors should also be required to provide equivalent incentive payments for desirable power factors.

- Costs that are presented as necessary for correction of power factor should be open for bid by third parties. As an example, the presentation by DTE on June 19, 2007 presents a cost of $20,000 per MVAR for power factor correction. If a third party can offer power factor correction for less than this rate, then they should be encouraged to do so.

- Generators should not be required to connect at unity power factor, but should have a strong incentive for connection at a desired power factor. A range of penalties and incentives for connection at various power factors should be specified, including bandwidths of power factors as shown in utility rates. Unity power factor should have neither incentives or penalties.

The utilities say that the Staff's proposed matching principle (generator and load customer) is misplaced because the parties are not similarly situated. They explain that a load customer pays a regulated rate for electric service that includes costs of power factor correction supplied by the utility. The utilities comment that a generator is not paying the power factor costs through the regulated rates; therefore the proposed “matching” actually creates a subsidy, since the costs of power factor correction caused by the generator are passed on to the utility and its other customers.

Identification of Areas of Opportunity on each Utility’s Distribution System

One commenter and the utilities suggested that this type of information could be provided by the utility at the pre-application meeting.

Insurance and Liability Issues

The utilities commented that many of the utilities participating in these comments agree that the provisions for minimum liability insurance and indemnity contained in Wisconsin Rule 119.05 are workable. Additionally, they say that it is well known in Michigan that the potential liability for tort damages can be greatly influenced by the venue; accordingly, the minimum insurance coverage should be adjusted for this increased risk, for those utilities rendering service in the higher risk areas. They suggested this should be discussed in the collaborative. The utilities added that another approach is simply to leave this issue to each utility, subject to a general requirement of commercial reasonableness in accordance with local practices. The utilities further commented that in either case, there should be requirements applicable to the project developer and the customer owning the generator during its time of use.

Based on issues identified during the interconnection investigation, the same additions to the Wisconsin Rules as proposed for the 10 kW and under workgroup were included in the Staff proposal sent to the workgroup for comments on August 22, 2007. Staff requested comments from the workgroup on the Wisconsin Rules and proposed additions by September 7, 2007. Two sets of comments were received, both indicating support for revising Michigan Rules using the Wisconsin Rules as a foundation, and incorporating several of the Staff’s proposed additions. Comments are provided in Appendix 2.

30 kW and Larger Interconnection Procedures Recommendations and Conclusions

Comments received indicate that Michigan utilities are generally receptive to adopting interconnection rules similar to those used in Wisconsin. Many of the issues presently affecting Michigan interconnections would be positively affected by adoption of the Wisconsin Rules. An added benefit would be the administrative efficiencies that multi-state utilities with Wisconsin customers would be able to realize by using similar interconnection procedures in Michigan.

Staff notes that Wisconsin has both Rules and Interconnection Guidelines. Michigan has Interconnection Standards (which are Administrative Rules) and Generator Interconnection Requirements (also referred to as Interconnection Procedures) which are approved by the

Commission. Based on the progress of this workgroup, Staff is anticipating that the entire set of Interconnection Standards will be replaced with a new set of Administrative Rules similar to the Wisconsin Rules. It is expected that the new Michigan Administrative Rules will also trigger the need for a revised set of interconnection procedures.

Staff expects large portions of Michigan's existing interconnection procedures can be maintained, intact, since great effort went into their development and they contain a lot of technical information related to Michigan utility distribution systems. Updating the current interconnection procedures to reflect the Wisconsin Rules should be an option considered by this workgroup. However, the standardized application form and interconnection agreement used in Wisconsin should be given serious consideration. During the rulemaking process, consideration must be given to whether some of the more technical information in the Wisconsin Rules, might be better placed in the Interconnection Procedures so that if future changes are necessary, these changes can be accomplished with a Commission Order; without formal rulemaking.

The following paragraphs outline the major goals Staff has identified, to be addressed through the proposed revisions to Michigan Rules:

1. Identify reasonable and achievable interconnection time deadlines.

   The Wisconsin Rules have separate and distinct steps for interconnection activities instead of a single deadline like the Michigan Rules. One area of concern with regard to timing is that the Wisconsin Rules allow the utility and developer to mutually agree on the timing of distribution system upgrades. As part of the rulemaking process, Staff recommends working towards incorporating maximum time limits for this step, for the various system sizes identified in the Rules.

2. Propose a system for determining whether interconnection costs are reasonable, actual costs.

   Staff recommends that applicants file formal complaints with the Commission, if contentions arise regarding interconnection costs. If needed, experts could assist the Commission with evaluating the compliant. Provisions like this are already incorporated into other Commission rules. Two examples are given in Staff's August 2007 proposal to the workgroup.[58] Should such a complaint arise, Staff proposes including in Rules a provision whereby a panel of one to three interconnection experts will assist the Staff in reviewing the utility interconnection cost information and evaluating the complaint. The utilities would pay for the cost of these experts. While the utilities are concerned with the costs of the experts, the fact that the applicant would be required to file a formal complaint and adhere to the complaint scheduling process places a burden on the applicant. The formal complaint process can take six months or longer to complete. The utilities will want to minimize the number of complaints filed and will likely make every

[58] See examples of two expert panel provisions in the Staff August 2007 proposal at http://www.michigan.gov/documents/mpsc/Staff_30_kW_and_larger_august_2007_proposal_and_comments_208245_7.pdf.

effort to work with applicants to resolve cost concerns that do arise. Staff believes this proposal strikes a reasonable compromise between due process and efficiency.

3. Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections).

   The transmission owners provided recommendations on when they thought consultation would be necessary. Staff notes that this issue is addressed in the Wisconsin Guidelines instead of the Wisconsin Rules. Staff recommends making provisions for transmission owner notifications in the interconnection guidelines/procedures rather than in the new Michigan Rules.

4. Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.

   Michigan Rules currently do not require all generators to operate at unity power factor. The utilities would like the new rules to require unity power factor for all generator interconnections.

   The Wisconsin Rules do address power factor issues. All interconnection projects sized 200 kW or less are to be operated at a power factor greater than 0.9. All others shall be operated at unity power factor or as mutually agreed between the public utility and applicant. This seems reasonable to Staff. Further consideration for larger generator interconnections can occur as work progresses on the new Michigan Rules.

5. Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system.

   Staff recommends that utilities provide information suitable for making interconnection location decisions: (1) on or contiguous to the premises of a single customer and (2) within a small prescribed area defined by the applicant or system developer. Utilities would provide this information at, or as soon as possible following, a pre-application meeting with the applicant and/or developer.

   Staff had recommended that each utility develop a map which indicates locations most suitable for the interconnection of distributed generation and most likely to minimize interconnection costs. Utilities strongly objected to this concept. Little interest was expressed by project developers or customers. Therefore, Staff does not recommend further consideration of this issue in the rulemaking process.

Other Issues

Insurance and Indemnity Language

Currently, in Michigan, requirements for liability insurance and indemnity language are not standard across utilities. These requirements are generally included in each utility's interconnection and operating agreement. The Wisconsin Rules have very clear liability insurance requirements based on the size of the interconnecting generator. The utilities like that the Wisconsin Rules require the applicant to provide a certificate of insurance with the application and comment that the levels of coverage are acceptable to some. The utilities want to have the opportunity to consider alternatives to the Wisconsin indemnity language. Further consideration will occur as work progresses on the new Michigan Rules. Staff's preliminary recommendation is to generally follow the provisions regarding liability insurance from the Wisconsin Rules, and Staff expects to support reasonable, fair indemnification language.

Pre-Application Meetings

Both utilities and developers reached consensus on the value of this type of meeting – especially for larger interconnection projects. In addition to receiving information needed to make location decisions, utilities can also discuss with the customer and/or developer possible rate impacts and any choices of available rate offerings that could be affected by the installation of on-site generation. MPSC Staff recommends that the revised Michigan Rules incorporate a pre-application meeting.

Waiver Process

The utilities proposed an informal waiver process where the utility and developer would agree to proposed system modifications and file a joint proposal for waiver with the Staff. The waiver would be automatically approved in a certain number of days, unless the Staff requests further information or a formal proceeding. Consensus was reached on this matter during the interconnection investigation. Staff agrees a waiver process should be included in the revised rules.