**STATE OF MINNESOTA**
**BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION**

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| **Phyllis Reha** | **Commissioner** |
| **Gregory Scott** | **Commissioner** |

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| In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities | E-999/CI-01-1023<br>June 26, 2003 |

# REPLY COMMENTS OF REGULATED ELECTRIC UTILITIES

## Introduction

These consolidated reply comments are submitted by Dakota Electric Association (Dakota Electric), Interstate Power and Light Company (Interstate or IPL), Minnesota Power (MP), Northern States Power Company d/b/a Xcel Energy (Xcel Energy) and Otter Tail Power Company (Otter Tail or OTP) and specifically address the Distributed Generation (DG) Tariff Issues that came out of the work of the DG Rate Workgroup.

On June 19, 2002, the Minnesota Public Utilities Commission (MPUC or Commission) issued its Order Organizing Workgroups and Setting Procedural Schedule in the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities. This order directed the Minnesota Department of Commerce (Department or DOC) to establish Workgroups to propose technical standards and rate standards governing interconnection of distributed generation facilities with utility electric distribution systems. On February 3, 2003, the Department issued its Report on Distributed Generation Technical Standards and Tariffs summarizing the results of the Workgroups, including independent recommendations from the Department. On February 18, 2003, the Commission issued a Notice of Comment Periods in this matter. On March 21, 2003, the following interested parties submitted comments:

Distributed Generation Coalition
Hennepin County
Great River Energy
Metro Cooperatives
Minnesota Municipal Utilities Association
Missouri River Energy Services
Regulated Electric Utilities

**Reply Comments**

The Regulated Electric Utilities find that we are in general agreement with the comments provided by Great River Energy, Metro Cooperatives, Minnesota Municipal Utilities Association and Missouri River Energy Services. Accordingly, we will not present any reply comments to the issues raised by these interested parties.

Following are reply comments of the Regulated Electric Utilities regarding issues raised in comments submitted by Hennepin County and the Distributed Generation Coalition.

<u>HENNEPIN COUNTY</u>

The Regulated Electric Utilities offer reply comments on the following issues raised in comments by Hennepin County on March 21, 2003:

- Certified transfer switches;
- Wholesale transactions;
- Calculation of avoided cost; and
- Pricing of standby services.

Certified Transfer Switches

Hennepin County suggests that "*any tariff providing for interconnection ensures that any distributed generation unit serving electric load during an emergency, which would otherwise be served by the utility, be required to have a certified transfer switch. The requirement for a certified transfer switch is simply to ensure safety and proper coordination of load, when a distributed generation unit is operating under emergency conditions, and when service from the local utility is restored following the emergency*" (Hennepin County comments at page 9). The Regulated Electric Utilities concur with this suggestion to require certified transfer switches.

Wholesale Transactions

Hennepin County comments on pages 10 and 11 raise a concern that the Department's report "*suggests that a utility must buy all energy supplied by distributed generation customers, and that a customer should be limited to selling distributed generation energy to the utility, using all of the energy itself, or self-generating for part of its needs and sell the remaining to the utility*." Hennepin County goes on to assert that all distributed generation facilities "*should be able to access utility distribution systems and sell the electric output to the wholesale market*." The Regulated Electric Utilities believe that we are in agreement with the points raised by Hennepin County and feel that the County's comments may reflect a misunderstanding of the relationship between proposed retail tariffs and wholesale transactions. The proposed generic standards developed by the DG Rate Workgroup were intended to cover retail transactions between Regulated Electric Utilities and their customers. Based on this relationship, the Rate Workgroup developed the "must buy" provisions between the utility and DG customer. Beyond this retail transaction, DG facilities are free to access the wholesale market to sell their electric output. Under such a scenario, the local utility would provide access to the distribution system to wheel power to the transmission grid. At that point, the DG customer would be responsible for making all necessary transmission and other contract arrangements. The local utility is not in a position to facilitate such wholesale market transactions on behalf of the DG facility. In addition, we note that this arrangement does not allow use of the local distribution system to make retail sales to other customers.

Calculation of Avoided Cost

The Regulated Electric Utilities would like to clarify that the consensus among interested parties regarding the calculation of avoided costs was that utilities would base such calculations on the current methodologies used to develop avoided costs in the Regulated Utilities' annual Cogeneration and Small Power Production filings.

Pricing of Standby Service

Hennepin County raises a concern regarding the pricing of standby services. Specifically, Hennepin County suggests that "*The standby customer should pay only the fixed reservation fee, whether standby capacity is provided during peak or nonpeak periods, along with a pre-determined capacity and energy usage charge when a customer exceeds a pre-determined load level*" (Hennepin County Comments at Page 12). The Regulated Electric Utilities assert that pricing for standby services should be based on the cost of providing such services. The ultimate pricing for these services should reflect the general statutory ratemaking principles that ensure that any rate is just and reasonable and not unduly discriminatory. With these principles in mind, the fixed reservation charge represents the utility's costs associated with maintaining required generation capacity reserve margins. If a DG customer actually requires electrical service under the standby provision, such electrical use should reflect the market costs that the utility incurs to provide such service. This ensures that the standby customer pays the cost for this service and that other ratepayers are not required to subsidize this service.

## DISTRIBUTED GENERATION COALITION

The Regulated Electric Utilities offer reply comments on the following issues raised in comments by the Distributed Generation Coalition, dated March 21, 2003:

- DG Definition;
- DG Ownership;
- Merchant Plant;
- DG Location;
- Demand Ratchet;
- Avoided Capacity Costs;
- Standby Rates;
- Maximum Size to Avoid Standby Charges;

- Physical Assurance;
- Distribution Credits;
- Diversity Credit;
- Renewable Energy Credit; and
- Emission Credits

DG Definition

On page 4, the DG Coalition suggests that further clarification is needed to help identify when a DG facility meets the tariff requirements. The Regulated Electric Utilities believe that each point of delivery should be treated as an individual facility; subject to the 10 MW limit and requiring separate application and analysis. In the first example involving multiple points of delivery, each less than or equal to 10 MW, the installations would be addressed individually, not grouped together and rejected since they total more than 10 MW. Although the engineering studies and analysis may be similar for the multiple locations in a common area, it is conceivable that the first one or two would be allowed while subsequent facilities would cause capacity constraints of the feeder and distribution facilities. If constraints exist, the customer would need to consult with the utility regarding line extension policies/customer contribution to facilities. The second example requiring use of utility facilities for intra-site wheeling is outside of the scope of this proceeding and not subject to the DG tariff. As stated by the DG Coalition on page 6, *"… all DG projects have the ability to negotiate directly with the utility outside the tariff"*, and that is certainly the case in this type of situation. Individual utilities may allow intra-site wheeling under limited circumstances, or may negotiate for the sale of on-site utility facilities, but these situations would be handled on a case-by-case basis.

DG Ownership and Merchant Plant

The DG Coalition correctly states that the Department's position on these two items was clearly defined in the March 18, 2003 clarification letter. The Regulated Electric Utilities support the Department's view that ownership be open to end use customers, the utility, third parties, or hybrid ownership. The Utilities also support the Department's view that the DG tariff not be available to Independent Power Producers (IPP's) or merchant plants.

DG Location

As discussed under the DG Definition section (above), the Regulated Electric Utilities *again* assert that requiring use of utility facilities for intra-site or distribution wheeling is outside of the scope of the proceeding and not subject to the DG tariff. As stated by the DG Coalition on page 6, *"... all DG projects have the ability to negotiate directly with the utility outside the tariff"*. Individual utilities may allow intra-site wheeling under limited circumstances, or may negotiate for the sale of on-site utility facilities, but these situations would be handled on a case-by-case basis.

Demand Ratchet

The DG Coalition is correct that the demand ratchet issue was raised briefly in the Rate Workgroup's discussions (DG Coalition Comments at Page 6). However, further consideration of demand ratchets was dismissed because properly designed rates and application of them should not result in "double charging" as the DG Coalition suggests in their example.

As a first step in responding to the comments of the DG Coalition on this issue, it must be understood why demand ratchets, and a similar rate feature known as an "annual minimum demand charge", are used. Both of these rate features are intended to assure that sufficient revenue is collected from a customer so that the fixed demand related costs of serving the customer are covered. For example, each customer has the exact same poles, wires and associated equipment in place to serve them every month of the year. The fact that a customer's metered demand use changes from month to month does not change the costs associated with serving this customer even though the revenue the utility will collect from the customer will change. Utility rates are designed recognizing the variability in customer demand use, but this is done so on an average basis. For customers that have a significantly higher variability in their demand over the year (greater that 50% in the DG Coalition's discussion), the demand ratchet or the annual minimum demand charge will make sure the customer pays a minimal fair share amount towards the fixed cost of facilities they have available to them at all times.

In looking at the DG Coalition example (DG Coalition Comments at Page 6), proper rate application yields a different result. Assuming the utility has a properly designed Standby Service rate, the application of the utility's rates would be as follows. The customer that has 6

MW of load before installation of 5 MW of distributed generation would have their service agreements changed to reflect the changed circumstances. The agreements would show that the customer has contracted for 5 MW of Standby Service and would pay the same monthly reservation fee each month for the 5 MW that has been contracted for. The agreements would further show that the customer has 1 MW of load that remains on the utility's general rates and it is only this 1 MW of load that is subject to the demand ratchet. The 3 MW of demand ratchet shown in the DG Coalition's example would not apply. The Regulated Electric Utilities are not aware of any utility in Minnesota that would apply their rates as described by the DG Coalition's example.

<u>Avoided Capacity Costs</u>

The Workgroup process addressed the methodology for determining capacity payments (DG Coalition Comments at Page 7). The scope and rate principles established by the Rate Workgroup in this docket support the position that a utility should only provide a capacity payment to a DG customer if capacity is needed, and then only at a price reflecting the value of the capacity to the utility and its customers (i.e., the utility's avoided cost).

- The scope of the docket, requiring that utilities file a DG tariff with the Commission, establishes a must-buy obligation (DG Rate Workgroup Report at Page 6). The Regulated Electric Utilities believe that utilities should only pay a DG customer for capacity under this must-buy (pay for) obligation if the utility actually needs the capacity and that utilities should not be required to buy more capacity than is needed. Another important part of the must-buy obligation is the price the utility must pay for the capacity.

- The rate principles established by the Rate Workgroup lay the groundwork for setting rates for services provided by DG customers to utilities, namely that rates should reflect: i) the value of the DG to the utility and its customers; and ii) the utility's avoided costs on the generation, transmission and/or distribution system.

On page 7 of their comments, the DG Coalition stated that they "*argued in the work group that the current resource planning system was not designed to accommodate the addition of incremental non-utility DG resources, and this can often result in barriers to DG…*" The DG

Coalition implied that utilities add resources in large blocks resulting in lengthy periods of time when a utility can claim that they have no need for capacity. They view this as discriminatory toward DG, because had the utility been adding smaller increments, their supply curve would more closely resemble their demand curve, and they would always have a need for capacity that could be supplied by DG.

The Regulated Electric Utilities disagree with the DG Coalition's characterization of the integrated resource planning process and instead agree with the Department's recommendation (that the need for capacity be established in the utility's most recently approved integrated resource plan). The Regulated Electric Utilities add that the need for capacity is defined only in the five-year action plan timeframe. Integrated resource planning, provided under Minnesota Statute 216B.2422, is a well-established process that requires each utility to file for approval a set of resource options that could be used to meet the service needs of its customers over a forecast period. As part of its resource plan filing, the utility presents an action plan as to how it will meet its needs in the first five-years. The resource plan is typically filed every two years, reviewed by the Department and other interested parties and is either approved, rejected or modified by the Commission.

The integrated resource planning process handles both large and small increments (as small as 1 MW) of demand and supply. It is not correct to assume that this process only encourages utilities to plan for large blocks of supply. A utility is constantly balancing its capacity needs with its committed resources. Furthermore, there are many reasons why a utility may show large incremental blocks of capacity need. These include: i) a utility's load may grow in large blocks (e.g., 8000MW at 2% annual growth requires 160MW resource addition per year); ii) the resource availability may change in large blocks (e.g., purchase power agreement expires, unit retirements); and iii) Customer demand changes may have a significant impact on the utility (e.g., large paper mill shuts down). <u>For these reasons, it is not correct to assume that the supply curve is a stair-step curve designed to meet a straight-line demand curve.</u>

On page 9 of their comments, the DG Coalition further states that "*As long as a utility states a need for capacity in its resource plan, DG generators should receive a capacity payment, with no discounting for when a utility may or may not have plans to add capacity*." The DG Coalition claims discounting to take into consideration the timing of the capacity need is also discriminatory.

The Regulated Electric Utilities disagree with the DG Coalition's characterization of the Department's recommended discounting formula and agree with the Department that capacity payments should be discounted to account for the timing difference between demand and supply. However, the Regulated Electric Utilities want to clarify that they agree with providing a discounted capacity payment only for capacity need established within the five-year action plan timeframe of the utility's most recently approved integrated resource plan.[1] If the capacity need is forecasted outside of the five-year action plan window, no capacity payments would be made.

Many factors support the argument that a current payment for a forecasted capacity addition is neither just nor reasonable. These factors include the uncertainty of a long-term forecast (e.g., load loss) and the fact that the DG customer, when not under a must-sell obligation, could decide to sell elsewhere, scale back or cease operations. Levelizing capacity payments to account for a purchase of capacity from a DG customer before there is an established need for capacity by the utility, while reducing the impact, still leaves <u>current customers paying for future capacity additions</u>. Using levelized capacity payments only for capacity need established in the five-year action plan timeframe limits the rate impact risk on the utility's other customers.

<u>Providing capacity payments prior to an established capacity need also sends the wrong price signals to DG customers</u>. The capacity should be priced based on its value to the utility. The utility or its other customers should not be required to subsidize the business plans of the DG customer.

Finally, by setting the planning period too far out in the future, the likelihood of overpaying for capacity increases. <u>Overpayment for capacity can also occur when a utility purchases capacity</u>

[1] The use of the five-year action plan timeframe is a compromise between the Department's recommendation that a capacity need exists if the utility shows a deficit at any year of the 15-year planning period and the regulated electric utilities' original position that if capacity is not needed by the utility at the time of the contract with the DG customer, the utility should not be required to provide a capacity payment to the customer. The use of the five-year action plan timeframe is also consistent with the rationale for determining capacity need in other forums (i.e., the planning period criterion of PURPA and of the Minnesota Cogeneration and Small Power Production Tariff ).

that is beyond what is needed (i.e., used and useful principle). Using a 15-year planning period versus a five-year planning period in conjunction with discounted advance payments to the DG customer for supply prior to the any capacity need by the utility could cause the utility to pay for service not required or needed.

Standby Rates

The Regulated Electric Utilities agrees with the DG Coalition that the setting of rates for Standby Service is not part of the Workgroup's purpose (DG Coalition Comments at Page 10). For some utilities, the rates, terms and conditions of Standby Service and related backup supply tariffs have been the subject of extensive proceedings before the Commission (Dockets E-002/M-96-337 and E-002/M-96-1355 for example). For other utilities, the Standby Service rates currently in effect are somewhat dated and do not reflect the current state of the utility industry. In either case, Standby Service is one family of offerings by individual utilities that must be reviewed within the framework of each utility's overall rate structure. An approach for providing backup supply to a DG customer that may be appropriate for one utility may not be appropriate for another because of the differing makeup and characteristics of the individual utility's system and resources.

Maximum Size to Avoid Standby Charges

The Regulated Electric Utilities already addressed this issue in their initial comments. However, the DG Coalition continues to characterize costs that a DG customer incurs to obtain Standby Service from a utility as a barrier or roadblock (DG Coalition Comments at Page 10). The fact a DG customer is required to pay the true costs for utility services and that paying these costs results in a detrimental impact on the DG project does not mean that Standby Service is a barrier or roadblock. It just means that a true and accurate evaluation of the total costs of a particular DG project must include all costs associated with it to be complete. The DG Coalition's request that some DG projects not be required to pay for Standby Services simply means that they are asking other ratepayers to pay for the costs that they cause. The Commission should reject this suggestion and not increase the size of DG facilities that are subsidized by other ratepayers.

Physical Assurance

The DG Coalition again suggests that a DG customer should be allowed to avoid paying for utility facilities connecting the customer's site to the utility's system (DG Coalition Comments at Page 12). Clearly there is benefit to the DG customer in being connected to the utility's facilities otherwise the customer would not ask for them. It is only reasonable that the DG customer pay their fair share for the use of these facilities. The DG Coalition even goes so far as to suggest that a new "green-field" DG customer should be able to have the utility connect new facilities to their site and then not pay the utility anything for having those facilities in place (DG Coalition Comments at Page 12). It is unreasonable for a DG customer to expect that other ratepayers will pay for the facilities that a DG customer requests or even requires the utility install for their use.

Distribution Credits

As stated in our March 21, 2003 initial comments, the Regulated Electric Utilities do not agree with the Department's recommendation that each utility publish on the internet its annually conducted distribution capacity planning study that identifies capacity needs, upgrades and load growth on area distribution feeders. This recommendation poses three concerns for the Regulated Electric Utilities. First, there are security concerns about identifying potentially vulnerable distribution areas on the Internet. Second, not all regulated electric utilities necessarily conduct an annual distribution capacity planning study. Third, the Regulated Electric Utilities question the value of publishing an entire distribution capacity planning study on the Internet versus a list of substation areas or feeders to potential DG customers that could be likely candidates for distribution credits. The Regulated Electric Utilities instead recommend that information be provided at a DG customer's request and treated as confidential.

Diversity Credit

On page 13 of their comments, the DG Coalition suggests that utilities give a diversity credit for DG installations that recognizes a reduced reserve margin of 8%. The DG Coalition claims that this is appropriate because smaller DG units require lower reserves on a diversified basis than larger utility generating units.

The Regulated Electric Utilities agree with the Department that no additional diversity credits for energy and capacity be given to DG customers who contact for standby service. Regardless of facility size, utilities must have sufficient reserve margin to provide standby services and avoid Mid-Continental Area Power Pool ("MAPP") penalties. The level of reserve margin each member has to carry is set by the MAPP, not by the utility. MAPP develops the reserve margin based on studies of existing generation and system contingencies in the region. As the generation mix changes because of the development of small DG, MAPP will adjust the reserve margins accordingly. However, in a region that has a mixture of large generation resources as well as many small generators, reserve margin levels will still be set by the existence of those large generators. Since any potential diversity benefit from small DG facilities will not translate to lower required reserve margins as required by MAPP, such a diversity credit is not justified on an avoided cost basis.

Renewable Energy Credits

The Regulated Electric Utilities agree with the Department that a DG customer who installs a renewable DG facility should be paid the avoided cost of "green power" to the extent that the DG facility allows the utility to avoid the purchase of "green power" elsewhere. Otherwise, the payment should be based on the utility's standard avoided costs. Following the Department's position, the Regulated Electric Utilities believe that any renewable energy credits should be cost-based and should only be applied if there are measurable benefits to the utility.

Consistent with the Department's position, as outlined in our March 21, 2003 comments, the Regulated Electric Utilities would like to emphasize the following three points regarding renewable credits:

- Utilities should be required to pay DG customers a renewable premium only when the utility needs more renewable power either as part of a program to sell renewable energy to customers or to meet other renewable objectives;
- DG facilities must be certified for participation in a renewable program; and
- Utilities should make such DG purchases at no more than the avoided cost of renewables the utility would have otherwise purchased.

It is not appropriate, as the DG Coalition assumes on page 14 of their comments, that utilities will have a continual need to add renewable generation into their portfolios and that there should always be a renewable credit provided to DG customers. This is not consistent with the rate principles established by the Rate Workgroup that lay the groundwork for setting rates, namely that rates should reflect: i) the value of the DG to the utility and its customers; and ii) the utility's avoided costs on the generation, transmission and/or distribution system.

The suggestion that renewable DG should receive a payment based on the premium price reflected in retail rates (e.g. Green Pricing Tariffs) ignores the fact that this retail price adder is necessary to deliver the renewable energy to customers on an equivalent load basis to the utility's other generating resources. Electric utilities are not making additional money from this retail price adder. Instead, the price adder reflects the higher cost of securing and delivering renewable energy to meet customer load requirements instead of more conventional generating resources.

Emission Credits

As stated in our March 21, 2003 comments, the Regulated Electric Utilities agree with the Department's position on tradable credits, but disagree with the Department's position on non-tradable credits.

a. Tradable Emission Credits

For a tradable emission, if a DG facility allows the utility to capture the value of the emission credit, then the DG customer should receive the credit revenues. Following the rate principles established by the Rate Workgroup, the Regulated Electric Utilities agree that it would be appropriate to pay only those avoided emission costs that can be quantified. At this time, the only emission that meets those criteria is SO2. There is an established market for SO2 credits and the Acid Rain Program requires affected utilities to have allowances available to cover it's SO2 emissions each year.

Should compliance for other tradable emission credits be required in the future for utilities, the Regulated Electric Utilities would agree to also pay those avoided emission costs at such time compliance is required. The utilities would not pay for avoided emission credits prior to the first period of compliance.

b. Non-Tradable Emission Credits

The Regulated Electric Utilities are strongly opposed to the Department's proposal that utilities pay non-tradable emission credits on the basis that the utility is not avoiding any actual costs for non-tradable emissions. The Department's concept goes against the rate principles established by the Rate Workgroup.

The Department further proposes that these credits should equal the utility's avoided emission costs, calculated as the emission per kWh of the next unit the utility plans to construct or purchase less the emission per kWh of the DG facility. The Regulated Electric Utilities disagree. Proposals evaluated in the resource planning process do not receive any direct compensation for producing lower non-tradable emissions, and neither should DG units. DG projects, whether evaluated in the context of a resource planning process or not, will already benefit from environmental externalities being included in the resource planning process because the results of this process are used to develop avoided energy costs.

Conclusion

The Regulated Electric Utilities appreciate the opportunity to provide these reply comments. If you or your staff have any questions regarding these reply comments, please contact: Doug Larson for Dakota Electric (763) 755-5122; Dave Prazak at Otter Tail Power (218) 739-8595; Dan Tonder at Minnesota Power (320) 632-2318, ext. 5031; Linda Hendrickson at Minnesota Power (218) 722-5642, ext. 3601; Dave Vognsen at Interstate Power and Light (319) 786-4679; or Paul Lehman at Xcel Energy (612) 330-7529.