STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Leroy Koppendrayer	Chair
Ellen Gavin	Commissioner
Marshall Johnson	Commissioner
Phyllis Reha	Commissioner
Gregory Scott	Commissioner

In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212

DOCKET No.: E999/CI-01-1023

June 27, 2003

RE: The DG Coalition Reply Comments on the Proposed Technical Interconnection Standards and Tariffs

BACKGROUND

On August 20, 2001, the Minnesota Public Utilities Commission (Commission) issued its Order Initiating a Docket for the purpose of establishing generic standards for utility tariffs for interconnection and operation of distributed generation ("DG") facilities. The Order was issued pursuant to a new law enacted in 2001 intended to obtain benefits of distributed resources by promoting their use (Minnesota Statute § 216B.1611).

On June 19, 2002 the Commission issued an Order for the formation of the collaborative Technical and Rates workgroups, headed by the Minnesota Department of Commerce, to draft documents and guidelines for the DG interconnection technical standards and tariffs.

On February 3, 2003 the Minnesota Department of Commerce filed the 'Report on Distribution Generation Technical Standards and Tariffs' (Final Report), a report of two workgroups convened to develop uniform guideline standards for DG. The workgroup report on DG tariffs was complete and final. The workgroup report on technical standards filed proposed only technical requirements, and requested additional time to complete development of standard interconnection procedures and an agreement.

On May 22, 2003 the Minnesota Department of Commerce submitted the ‘Phase II Report of the DG Technical Standards’ (Phase II Report) – a completed DG interconnection technical standards report.

In its March 31, 2003 Notice of Revised Comments Schedule, the Commission set June 27, 2003 for the submittal of the reply comments on the proposed Technical Interconnection Standards and Tariffs.

INTRODUCTION

The following are the reply comments of the DG Coalition, a group of organizations representing a wide range of energy interests. The DG Coalition presents the consolidated view from representatives of environmental groups, distributed energy developers, renewable energy advocates, natural gas utilities, economic development interests, a large business association, and a county government. Individual groups signing on to these comments include: CenterPoint Energy Minnegasco, Hennepin County, Institute for Local Self-Reliance, Izaak Walton League of America - Midwest Office, Korridor Capital Investments LLC, Minnesota Chamber of Commerce, Prairie Gen, and The Minnesota Project.

We appreciate the opportunity to submit our comments. We also acknowledge the efforts of the Minnesota Department of Commerce (Department) for organizing the collaborative DG workgroups meetings and summarizing the outcome of the completed rates and technical sections in the Distributed Generation Technical Standards and Tariff Report and Phase II Technical Standards Report dated February 3, 2003 and May 22, 2003 respectively.

The collaborative workgroups meetings have allowed a valuable forum to raise and discuss critical issues to shape the distributed generation interconnection standards and tariffs in Minnesota. Although the DG workgroups reached general consensus on some key items, the unresolved issues still impose onerous obstacles to promote DG in Minnesota. The DG

Coalition has outlined the unresolved items that require further Commission action, and respectfully ask the Commission to consider it during the decision making process.

DG TECHNICAL INTERCONNECTION STANDARDS

The Phase II Technical Standards Report (Phase II Report) outlines a detailed set of the DG interconnection standards for Minnesota. These standards are a significant step in establishing a foundation to provide a common look for each of the utilities and customers wanting to interconnect DG systems in Minnesota. Although it contains a comprehensive set of procedures, requirements, and agreements, the unresolved issues still pose significant barriers to apply the interconnection technical standards as outlined in the current form. The Commission's action is crucial to mitigate the persistent barriers and allow the promotion of the DG systems in Minnesota.

1. Engineering Studies

Utility Response Timelines

The proposed interconnection process fails to establish any timeline for the completion of the engineering studies. The DG Coalition believes that an interconnection process without a timeline for engineering studies represents a missed opportunity and represents a barrier to DG development. We note that most interconnections proposed under this process will move quickly, will not require extensive study, and will result in benefits for the DG customer and the local utility. Timelines will not create unreasonable burdens on utilities.

The DG Coalition strongly supports establishing a fix timeline for all engineering studies performed under Minnesota Interconnection Standards. Timelines are standard in states where DG Interconnection Standards have been established. A clear start date and deadline for the completion of engineering studies ensures that such studies will be completed in an expeditious manner and removes a significant market impediment.

As several of the utility respondents indicate, most engineering studies can and will be completed quickly, especially for projects that are small and/or pre-certified. We absolutely agree that above all, safety and reliability are the most important issues. However, these conditions do not mean that deadlines are unnecessary.

Engineering study timelines have been adopted or are under consideration in several states, including Texas, New York, Massachusetts (proposed), and the NARUC model. Each calls for varying time limits for engineering studies. The Minnesota Public Utilities Commission should join these states and establish in this proceeding a maximum amount time allowed for a utility to complete an engineering study on behalf of DG customers.

The DG Coalition supports setting engineering study timelines in harmony with those established in the State of Texas. Texas allows utilities four (4) weeks to complete an engineering study on DG projects proposed on non-networked distribution systems, and six (6) weeks for projects proposed on networked systems. We believe that the majority of projects will be proposed for non-networked systems.

Without establishing a deadline, interpreting the appropriate length of time necessary for engineering studies becomes the responsibility of utilities and customers. Clearly, this will result in conflict, as customers will generally want a rapid turnaround, and utilities may have scheduling issues, may be unfamiliar with the proposed technology, or have other projects with higher priority. The Commission should order that four (4) weeks to complete an engineering study is appropriate, feasible, and desirable for most DG projects.

The DG Coalition is willing to address unusual cases, as Xcel Energy's comments describe: "…every engineer in the work group recognized that there are situations where circumstances beyond the utility's control can take more time" to complete an engineering study[1]. We agree, under extreme circumstances or very complex projects, that four to six weeks may not be adequate to complete an engineering study. Thus the DG Coalition proposes two options to deal with these situations:

[1] Xcel Energy comments on Phase II Report, June 6, 2003.

1) Always allow DG customers to hire independent engineering consultants to conduct the engineering studies on the DG's behalf. Price and timeline to be negotiated by the DG customer. The engineering consultant would coordinate with the utility to gather the relevant information, study the system, and recommend any changes necessary. This would free up utility resources, allow a rapid completion, and assure an independent study.

2) Allow an extended study period for the most extreme circumstances. Such an extension would be subject to negotiation between the utility and customer and may by reviewed by the Commission. Such cases would be rare, but such an option may be appealing in extreme circumstances.

Option for Third Party Engineering Study, In Lieu of Utility Study

As proposed above, the DG Coalition believes that DG customers should always have the option of hiring an outside consultant to complete engineering studies on their behalf. Such an option will provide the customer with an unbiased, independent analysis of the proposed project. Hiring outside consultants may also relieve some utilities fears that DG requests and associated engineering studies will overwhelm engineering departments.

The DG Coalition proposes such a third party option for all DG projects, regardless of a utility's ability to conduct a project in an expeditious manner. Allowing third party review not only ensures independence, but also will reduce any burden associated with DG customers requesting interconnection and engineering studies. A third party study also allows a customer to purchase an engineering analysis that best addresses the customer's proposed technology and business operating characteristics. Finally, a third party analysis may be less expensive, saving the customer money.

The DG Coalition recognizes the concern for the safety and quality of the analysis, and suggests that any third party should be a registered professional engineer.

Allow Certain Projects Engineering Fee Exemption

Many national studies of DG market barriers indicate that high transaction costs, especially for smaller projects, can erode first year and long term savings for DG customers. The Minnesota Legislature - Minnesota Law 2001, Chapter 212 - includes language that calls for interconnection standards that help to remove market barriers and encourage the deployment of DG technologies.

The DG Coalition reiterates its earlier proposal to mirror the Texas interconnection standards and allow exemptions from engineering fees for projects that meet specific criteria (see DG Coalition comments on Phase II Report, June 6, 2003). DG projects that meet the criteria will likely have low engineering costs, are safe technologies that utilize inverter-based safety functions, and will be small projects. The DG coalition speculates that many of the projects that qualify for such an exemption will be net-metered renewable projects and some natural gas fired projects for farms and small businesses. These are the exact types of projects that face the greatest threats from high transaction and engineering costs. Larger, more complex commercial or industrial projects may have a greater ability to absorb these costs, as they are smaller portion of overall costs.

The DG Coalition believes that exempting such projects will encourage the development of small, pre-certified, inverter-based DG installations such as micro-turbines, photovoltaics, wind turbines, and eventually, fuel cells. These technologies have or are in the process of being tested by nationally recognized testing laboratories, such as Underwriters Laboratories, and will meet national pre-certification standards. These technologies offer the DG customer a rapid interconnection, safety, and a solution to a specific need.

Engineering study fees are likely to be modest for these projects. Thus, the DG Coalition does not believe that exempting such projects will become a burden on the ratepayer. Statewide, to date, the number of projects that meet these criteria probably does not exceed 100 overall installations.

2. Insurance Issues:

In the developing the technical interconnection standards, the issue of insurance was deemed a controversial issue by the work group. A summary of the views put forward in the last round of comments by the utilities follows:

> Xcel Energy was generally supportive of the proposed levels of insurance requirements but believes that the insurance requirements are "on the low side" and expects that the minimum levels of coverage "may need to be raised." Xcel gives no examples of claims history to support this assertion.
>
> Minnesota Power agrees with the proposed levels of insurance requirements. Minnesota Power cites "significant risks associated with distributed generation interconnection for utilities and the customers they serve…" However, Minnesota Power did not offer any claims history or concrete examples of any distributed generation project causing a problem to their system.
>
> Dakota Electric Association "anticipates that once the insurance experts look at the risks involved with operating a generating resource they will be recommending higher levels of insurance than what is presently required." Dakota Electric did not offer any claims history or other information to back up their implication that DG projects are risky.

The Minnesota electric utilities correctly point out that some other States have adopted insurance requirements as part of their interconnection standards that are comparable to levels being proposed in Minnesota. However, the DG Coalition would like to point out a couple of alternative approaches that have been adopted.

First, the National Association of Regulatory Utility Commissioners (NARUC) Model DG Interconnection Agreements did not recommend that DG Customers provide insurance. NARUC's guidelines said:

7.0 Insurance

The Customer is not required to provide general liability insurance coverage as part of this Agreement, or any other Company requirement. Due to the risk of incurring damages, the [State regulatory commission] may recommend that every distributed generation Customer protect itself with insurance or other suitable financial instrument sufficient to meet its construction, operating and liability responsibilities pursuant to this Agreement. At no time shall the Company require that the Customer negotiate any policy or renewal of any policy covering any liability through a particular insurance company, agent, solicitor, or broker.

8.0 Effect

The inability of the Company to require the Customer to provide general liability insurance coverage for operation of the DG is not a waiver of any rights the Company may have to pursue remedies at law against the Customer to recover damages.

9.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction, such portion or provision shall be deemed separate and independent, and the remainder of this Agreement shall remain in full force and effect.

Secondly, the State of New York has adopted an approach to insurance that makes insurance coverage recommended but not required. It is similar to the NARUC model. This is how the State of New York deals with insurance in their DG Interconnection standards:

VII. INSURANCE

7.1 Disclosure: The Customer is not required to provide general liability insurance coverage as part of this Agreement, the SIR, or any other Company requirement. Due to the risk of incurring damages, the Public Service Commission recommends that every distributed generation customer protect itself with insurance, and requires insurance disclosure as a part of this Agreement. The Customer hereby discloses as follows:

(Note: Check off one of the boxes below.)

[ ] the Customer has obtained, or already has in effect under an existing policy, general liability insurance coverage for operation of the Unit and intends to maintain such coverage for the duration of this Agreement (attach Certificate of Insurance or copy of Policy); or

[ ] the Customer has not obtained general liability insurance coverage for operation of the Unit and/or is self-insured.

7.2 Effect: The inability of the Company to require the Customer to provide general liability insurance coverage for operation of the Unit is not a waiver of any rights the Company may have to pursue remedies at law against the Customer to recover damages.

The argument for the DG interconnection insurance requirements is to protect both the Area EPS and DG Customer in the event of an accident. The DG Coalition believes that adequate insurance coverage is an important protection that both the Area EPS and the DG Customer should maintain and is a common sense business practice. The financial burdens on the DG Customer from the proposed levels of insurance coverage appear to be minimal.

However, the DG Coalition believes that other provisions in the proposed insurance section are burdensome and unnecessarily raise red flags with insurance companies and insurance underwriters that have a lack of claims history or information on the safety of interconnected distributed generation projects. Specifically, the requirements that some DG customers must include the Area EPS Operator as an additional insured and have cross-liability clauses in their policies seem unwarranted. These clauses could unnecessarily impact the insurance premiums of the DG customer (Section XI.B on Page 8 of the Interconnection Agreement - Attachment 5 and Section F of the Proposed Interconnection Process for Distributed Generation Systems). The DG Coalition respectfully asks the Commission to remove the clauses from the DG insurance requirements sections in order to mitigate this potential barrier to DG in Minnesota.

The DG Coalition is supportive of the umbrella coverage and self-insured clauses in the interconnection agreement.

The DG Coalition would encourage the Commission to monitor the insurance issue over time as part of the ongoing oversight of how well the DG standards are working in Minnesota and to ensure that insurance requirements do not present a barrier to DG development.

3. Operating and Maintenance Agreement

The DG Coalition reiterates its argument that the operating and maintenance agreements (Exhibit D and E of the Interconnection Agreement) should not be made mandatory for the DG customers, especially to those customers who are not selling power back to the utility grid system. These agreements are unnecessary and will create time delay and unwarranted added costs to the DG customer. These agreements can be rolled into the Interconnection Agreement as separate section if needed. In addition, any such operating and maintenance provisions should be reasonable and should not exceed standard utility practice.

4. Interconnection Agreement and Process

The DG Coalition has outlined its comments and recommendation in the initial technical comments filing[2]. Our major concern is that the current language in the Interconnection agreement seems one sided and leans in favor of the Area EPS. It needs further revision to achieve a more balanced approach. We respectfully ask the Commission to consider our recommendations as outlined in the initial comments during its decision process.

Minnesota Power has proposed revisions to the Interconnection Agreement in its initial technical comments[3]. Although most are typographical and non-substantive, some of their proposed changes in the provisions would further negatively impact the DG customer. The DG Coalition disagrees with the following proposed revisions as outlined in Section III on page 5 and 6 of Minnesota Power's initial comments:

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[2] Initial comments of the DG Coalition on Department's Phase II Report, June 6, 2003.
[3] Initial comments of the Minnesota Power on Department's Phase II Report, June 6, 2003.

III (1): Minnesota Power asks for adding the language "and any applicable tariffs of the Area EPS Operator" in Section I (C) of the Interconnection Agreement. The DG Coalition disagrees with adding this language since it broadens the scope of the clause substantially. It is like opening Pandora boxes and requires a massive search for any issues that may impact the DG tariff. Furthermore, this gives the utility the opportunity to change the DG through indirect mean. Instead, we recommend that all tariff and service rules should conform with those new DG standard rates.

III (11): Minnesota Power proposed to add the language in Section XII (E) (3) of the Interconnection agreement that those tariffs may be amended by the utility from time to time. This is another example of indirect means to change the DG standards, and should not be added.

III (14): Minnesota Power proposed a clarification for non-warranty by the utility statement in Section XII (I) clause of the Interconnection Agreement. The DG Coalition disagrees with the entire non-warranty clause in the Interconnection Agreement. The DG Coalition argues the utility is charging DG customers for the studies, and therefore, it should be held responsible for providing warranties of its services.

Minnesota Power in its June 12, 2003 comments on the Process asks for an addition of the following language to the general section text of Interconnection Process on page 9 of 20 (Phase II Report): *"Notwithstanding the foregoing, the Interconnection Customer will be responsible for…"* The DG Coalition believes that this legal language is unwarranted under the Interconnection Process section. The fee requirements and the actual costs requirements are already stated in the proceeding steps where it justified. The DG Coalition supports the other changes recommended by Minnesota Power in its June 12, 2003 comments.

DG TARIFFS

The collaborative meetings have allowed a valuable forum to raise and discuss critical issues to shape the distributed generation (DG) tariffs in Minnesota. The Department captured the workgroup's discussion in its Final Report dated February 3, 2003. Although the DG Rate Work Group reached general consensus on some key items, the unresolved issues still impose obstacles to promote DG in Minnesota. The following discussion outlines the unresolved items that require attention from the Commission during its decision making process.

1. Cooperatives and Municipal Utilities Concerns About Adding DG

There have been some concerns put forward by cooperative (coops) and municipal-owned (munis) utilities about the "must-buy" requirements of a standardized DG tariff. The DG coalition firmly believes that the overriding principle agreed upon in the very beginning of the work group process was that the DG tariff was designed to be a "must buy" situation per the decision of the DG Customer. It is expected that the DG customer will have full control over how much energy/capacity to assign to the tariff. Further, we believe that a DG project's capacity should always be eligible for a capacity payment under the tariff.

Citing the existence of sole source contracts with generation and transmission utilities, the distribution-only munis and coops argue that they shouldn't be required to purchase excess energy and capacity from DG projects because they are often bound by existing power supply contracts. The DG Coalition agrees with Missouri River Energy Services on this point and agrees that the wholesale power G&T utilities should be permitted to assume the purchase obligations of its member customers. A solution, in part, to this dilemma already exists in State Law as part of the net metering statutes (see below).

> Minnesota Statutes
> §216B.164 Cogeneration and small power production.
> Subd. 3. Purchases; small facilities.
> (d) If the qualifying facility is interconnected with a nongenerating utility which has a sole source contract with a municipal power agency or a generation and transmission

utility, the nongenerating utility may elect to treat its purchase of any net input under this subdivision as being made on behalf of its supplier and shall be reimbursed by its supplier for any additional costs incurred in making the purchase. Qualifying facilities having less than 40-kilowatt capacity may, at the customer's option, elect to be governed by the provisions of subdivision 4.

While the existing state law only applies to qualifying facilities, the Commission should investigate whether it has the authority to extend this provision for DG projects up to 10 MW through Order or Rulemaking. It makes sense to allow distribution-only utilities to pass through "must buy" costs related to DG projects to their wholesale power supplier.

We would like to point out an issue related to must-buy capacity. The DG Coalition believes that utilities and ratepayers will be held harmless by the "must buy" provisions even if the respective utility is not projecting a need for additional generating capacity. This is because of regional efforts that will allow utilities to re-sell any surplus generating capacity into the MISO market that is expected to be established in March 2004.

2. Standby Charges Exemption for Projects Under 100 kW

The Commission has been directed by the Legislature to develop the technical standards and tariffs for distributed generation in Minnesota. The Statute suggests that the Commission should "promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints." Providing DG projects that are 100 kW or less in capacity with an exemption from standby charges is a modest proposal that is clearly directed at the residential and small business customers around the state.

Until July 29, 2002, Xcel Energy offered potential DG projects less than 100 kW in its service area an exemption from standby charges. It is unlikely that any cost impact or subsidization by other ratepayers occurred prior to that date. It is also important to point out that Xcel did not ask for any decrease in the standby limit to 40 kW during its initial DG docket filing on July 12, 2001 (Docket No. E-002/M-01-937). The issue only surfaced in their reply comments under the same docket dated November 19, 2001. In their reply comments, Xcel stated, “there is a tariff gap for DG between 40 and 100 kW and Xcel Energy will as part of a compliance filing propose to fill the gap with its Standby and Supplemental Service tariff.” The sequence of events prevented any DG customer to present arguments against their proposal until the hearing.

The DG Coalition notes that the Commission, in its July 29, 2002 order on Xcel Energy's DG Tariff (Docket No. E-002/M-01-937), concluded that "NSP’s tariff shall not constitute precedent for distributed generation energy tariffs or guidelines being developed in Docket No. E-999/CI-01-1023 In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212."

The DG Coalition believes that the Commission can meet its statutory responsibilities to promote distributed generation in Minnesota by returning to previous practice and provide the smaller DG projects an exemption from stand-by charges for DG projects of 100 kW or less in capacity.

3. Standby Rates

The standby charges, particularly the reservation fees, represent a barrier for the DG development, and they will continue to represent a major hurdle for the DG development in Minnesota if charges are allowed to continue at the same level. The DG Coalition agrees that standby charges should reflect that a portion of the system is being held available to provide backup utility service. However, these charges should be a fair reflection of the utility’s costs.

The DG Coalition supports the Rates Workgroup consensus and Department’s argument as outlined in the Standby Rates section of the Department’s Final Report:

> 1.a. DG customers do not have to buy the standby power. However, if the standby power is not bought, it may not be available.

> 1.b. DG customers do not have to buy as much standby power to cover the full amount of their own DG capacity. However, if for example they have a 5 MW DG and buy only 2 MW of standby power, there must be a guarantee that the DG facility will never take more than 2 MW of standby service.

The above two provisions allow the DG customer to manage the DG system unscheduled outages risk at its own level by exploring other options instead relying on the utility for a back-up. For instance, a DG customer may elect to have another back-up unit instead of relying on the grid, or a DG customer may be able to shed its load in the event of an unscheduled outage.

The regulated electric utilities in their consolidated comments[4] interpret the above provision, particularly section 1.a., as "the consensus of the Rate Workgroup was that DG customers do not have to buy standby ***generation supply.****"* The DG Coalition disagrees with this statement. Applying the electric utilities' interpretation narrows the scope of this provision where a DG customer can opt out of the generation portion but still be held liable for the transmission and distribution portion of the standby reservation charges regardless of taking or not taking the standby tariff. The DG Coalition believes the scope is intended to cover the entire standby power requirements including the generation, transmission, and distribution reservation charges. If a DG customer decided not to elect the standby tariff, the standby charges should not apply.

The above provision is also critical to interpret the Physical Assurance. If a DG customer elects the Physical Assurance, the generation, transmission, and bulk distribution reservation charges should not be imposed. Although the DG Coalition in its initial comments agreed that a portion of the distribution charges (non-bulk) might be necessary to pay as a standby reservation fees, we believe these charges are still excessive. The same customer, as a retail customer without DG, can minimize its load permanently without being penalized by its area electric utility. Thus, the DG Coalition believes the physical assurance provision is similar to a retail customer shedding its electric load permanently. In addition, any new DG load (i.e.

[4] Consolidated comments of Regulated Electric Utilities on the Department's Final Report, March 21, 2003.

green-field or capacity addition) with physical assurance option should have no standby charges[5].

Non-firm Standby should be allowed

The regulated electric utilities in their consolidated comments (March 21, 2003) raise the concerns of the safety and reliability limitations and recommends that the non-firm standby be excluded from the standard tariff, and instead recommend that the service be available on a negotiated, case-specific basis. The DG Coalition disagrees with this recommendation. The non-firm standby tariff should be allowed. It provides a DG customer with an option to limit its standby requirements from the utility. If there are any legitimate safety and reliability concerns, those DG customers could be disallowed from the non-firm standby option assuming the utility justifies the reasoning.

4. Avoided Capacity Costs

In the DG Coalition's initial comments, we agreed with the Department of Commerce and the Regulated Utilities that DG should be compensated for the benefits of the accredited capacity they add to a utility's system, providing they need capacity, as determined by stating need at any time in their most recent 15-year resource plan. However, we disagreed with the Department's plan of discounting capacity payments based on when the capacity would be needed.

In their consolidated comments, the regulated electric utilities agreed with the Department's discounting method, and state their position that the timeframe for determining capacity needs should be 5 years, rather than 15 years. It should be noted that both the utilities' proposal and the Department's would limit capacity payments to DG customers more than Xcel's current small DG tariff, which allows an undiscounted capacity payment based on avoided costs.

Any discounting for time period is discriminatory against DG

Any tariff the Commission adopts should, at the very least, not be discriminatory towards DG. As we argued in our initial comments, if a utility has a situation of increasing load demand,

[5] Initial comments of the DG Coalition on the Department's Final Report, March 21, 2003.

this increase tends to be a fairly smooth and steady increase over time, in contrast to supply increases, which tend to be in large blocks. Thus if the utility were to meet supply requirements in the most economically efficient way (no excess capacity), it would add generation incrementally in small amounts each year, such as can be supplied by DG facilities. Essentially, it would always have a need for capacity. It is this practice of adding capacity in large blocks that shuts DG out of getting a full capacity payment under the Department's proposal.

Since capacity is added in large blocks, there tends to be long periods of time where no supply is added. This is also somewhat inefficient, because the utility then has a period of excess capacity. The excess capacity means that the utility is paying for capacity that it is not using, for capacity acquired under the resource planning process. The main argument for discounting is that if a DG facility comes on-line before the capacity is needed, it is providing excess capacity. However, as is shown here, utilities routinely pay for excess capacity under the resource planning process, as the practice used by utilities is somewhat inefficient. And yet, the DG facility is providing capacity just the same as a block of capacity, and will continue to provide capacity for the life of the project, and should be fully compensated for it.

It should be noted that since the capacity payment for DG will be based on the utilities' avoided cost, it will be no more expensive for the utility to purchase DG than to purchase capacity from a large project. So there should be no objection to DG capacity additions on the basis of cost.

The utility should always pay accredited DG resources a capacity payment, as long as capacity additions are needed within 15 years

We agree with the Department's position on this matter. We concede that a utility that does not have an increasing demand and does not need the capacity should not have to pay for that capacity, but the appropriate time frame for considering this is over the 15 year period of the utility's resource plan. However, as mentioned earlier in these comments, regional efforts will soon allow utilities to re-sell any surplus generating capacity into the MISO market that is expected to be established in March 2004.

Therefore, capacity payments may not need to be limited by the projected needs of any particular utility since the regional marketplace can absorb any excess capacity.

Once a DG customer qualifies for a capacity payment, they should receive it for the life of their project

Although this may not be an item of contention, the Commission may want to clarify this point. Once a utility builds a (non-DG) project to provide capacity to their system, it becomes part of their "capacity base," and they receive the benefit of that capacity for the life of the project, even when they add more capacity later. It should be no different for DG customers. If they qualify for a capacity payment, they should receive it for the life of the project, even if the utility changes its status of needing capacity. If the Department prevails on the issue of discounting, the DG customer should receive the full capacity payment starting in the year the utility needs capacity, and receive that full payment for the rest of the life of the project (i.e., the DG generator enters the "capacity base" of the utility).

5. Online Access to Up To Date Information on DG Interconnection in Minnesota

The DG Coalition believes that the Commission or the Department of Commerce should set up a web page that is the one-stop information source for someone seeking to develop a DG project in Minnesota. We offer the following list as a starting point for what should be available on the web page:

Formal Interconnection Documents:

Overview of the entire Process in the layperson terms
Interconnection Process Document
DG Interconnection Technical Requirements
Interconnection Application Documents
Engineering Data Submittal Document
Interconnection Agreement

Other Information:

Listings of constrained areas on distribution system (potential distribution credit)

Answers to Frequently Asked Questions

Contact Information for DG Interconnection Coordinator(s) at each utility

Annual Reports of How DG Standards are working

List of Mediators for Dispute Resolution

Utility Distribution Capacity Planning studies

6. Distribution Credits

The DG Coalition reiterates support for distribution credits.

Based on comments of all stakeholders, there is overall consensus on allowing DG customers to share the financial benefits that DG projects bring to the distribution system. These benefits can mean that a utility may be able to avoid or delay a distribution line addition or distribution substation upgrade. These savings can be substantial and help to keep electricity prices low for ratepayers. DG customers should be financially compensated for bringing benefits to the distribution system.

The DG Coalition advocated for the distribution credit within the rates workgroup. Such a credit, and determining where DG is most beneficial, will help identify locations where DG installations may make financial sense for both DG customers and the local utility.

Distribution System Study on the Internet

The DG Coalition believes that specific information about utility distribution systems is beneficial to DG customers interested in developing DG within a utility service territory and should be posted on the Internet site. For those willing to pursue DG in areas that benefit the system the most, this information is essential.

In the March 2003 round of comments from the consolidated utilities, security concerns were raised about putting information related to constrained areas on their distribution systems on the Internet. Relieving strain on the existing electrical distribution system is one of the primary benefits that DG can provide to the electric system. It is clearly one of the primary reasons that the legislature has directed the Commission to develop standards for DG interconnection. Constructing DG projects where the system is constrained or is projected to become constrained can delay investments in grid projects and save ratepayers money.

We agree with the joint utilities proposal to provide a listing of substation areas or feeders to potential DG customers that could be likely candidates for distribution credits. We believe that a listing of this type could be made available on the Internet site and not be considered a security risk. We believe the most recent distribution capacity planning study of each utility should also be made available to DG project developers via the Internet site. It is the understanding of the DG coalition that these studies are publicly available right now from the Commission and we would not support an effort to make these reports proprietary in the future.

Limit Distribution Credit Study Fees to Application Fee

Upon receiving a DG application, utilities can make a simple determination whether a DG project will have a positive impact on a distribution system by consulting with distribution engineers and/or their own distribution system studies. Application fees that DG customers will be paying to utilities can cover this work. No additional fees should be charged, nor should be necessary for an initial determination of eligibility for the credit.

7. Renewable Energy Credit

In our initial comments, the DG Coalition agreed with the Department position that a DG facility should be paid a credit for producing renewable energy (above and beyond the energy and capacity value of the electricity), to the extent that the utility needed the green power. In addition, we argued that because current law creates an increasing need for utilities to produce renewable energy, utilities should always pay this credit, as part of their "good faith effort" to meet this state law. We further argued that setting the renewable credit at the same level as the green pricing premium (minus marketing costs) was the most logical and equitable way to establish the credit.

In the consolidated comments, the Regulated Electric Utilities raise the following three points[6]:

1. A green credit should only be paid when the utility needs more renewable power;
2. DG facilities must be certified for participation in a renewable program; and
3. Utilities should make such DG purchases at no more than the avoided cost of renewable the utility would have otherwise purchased. The regulated electric utilities argue against setting the renewable energy credit at the level of the green pricing premium.

We are pleased that the utilities agree with the concept of a green credit, and respond to each of their concerns below.

The Commission should require that a renewable energy credit always be paid to a DG customer that produces renewable energy.

The comments of the Regulated Electric Utilities seem to imply that a utility should pay a renewable credit only if the utility needs renewable energy in the year that the DG customer's generator comes on-line. The DG Coalition would urge the Commission from taking such a narrow view of the issue, which would only serve to make it more difficult for DG projects to receive full compensation for the real benefits they provide to the utility.

As we argued in our initial comments, current state law[7], especially the Renewable Energy Objective (REO), ensures that utilities will, for at least the next 10 years, have a continual need to add renewable energy to their portfolios. Even if the utility meets their requirements in a particular year, by the next year their requirements will have increased. It would add much more certainty to the DG market if a project developer could be assured of receiving the renewable energy credit, rather than having the availability of the credit vary from year to year.

[6] Consolidated comments of the regulated electric utilities, Pg. 28, March 21, 2003.

[7] Current Minnesota laws requiring utilities to purchase renewable energy include: 1) Renewable Energy Objective (MN Stat. § 216B.1691), requiring all utilities to purchase 10% of their power from renewable sources by 2015; 2) Green Pricing Program (MN Stat. § 216B.169), requiring utilities to offer renewable energy to their customers; and 3) Xcel Energy Wind and Biomass Mandate (MN Stat. § 216B.2423 and 216B.2424).

Since we wrote those comments, the Prairie Island bill (2003 1st Spl. Sess. HF-9) passed by the Minnesota legislature has firmed up the REO and increased Xcel Energy's commitment to small DG wind, by requiring them to purchase 100 MW of wind from projects under 2 MW. This makes the case even more compelling that utilities should always pay a renewable energy credit to renewable DG customers, as their needs to acquire renewable energy have been affirmed.

The value of the renewable credit should be set at the level of the green pricing premium

Throughout the workgroup's process, participants agreed that any credits given by the utility to a DG customer should reflect the actual costs and benefits to the utility. Thus the value of the renewable credit should reflect the incremental cost to the utility of acquiring renewable energy, compared to its cost of nonrenewable energy. Fortunately, Minnesota law has already set a process for this very calculation.

The legislatively mandated green pricing program requires utilities to offer its customers renewable energy for a price premium. This premium, by law, is set at the utility's cost of acquiring the energy and must: "reflect the difference between the cost of generating or purchasing the renewable energy and the cost of generating or purchasing the same amount of nonrenewable energy."[8] Although the statute does not mention the cost of administering a green pricing program, utilities have been allowed to capture these costs in the process. Thus if these costs are subtracted out, the green pricing premium reflects the incremental costs the utility actually pays to acquire renewable energy.

Although the Commission could set other processes for determining utility costs of procuring renewable generation, the DG Coalition believes that tying the renewable credit to the green pricing program is in the public interest. It is a built-in customer protection that will assure customers that the utility is not profiting from the premium that they charge. The ultimate assurance is that customer's knowledge that if they were to generate renewable electricity they would be compensated the exact same amount (minus administrative costs) that they would have to pay to purchase renewable energy from the utility.

[8] MN Stat. § 216B.169

On the other hand, imagine if the utility somehow charged customers more for renewable energy than it returned to customers that generated renewable energy. Surely once this fact became widely known this would not only cause irreparable damage to the utility's green pricing program, but also a loss of trust in the regulatory process.

We would also like to re-iterate our position that if the biomass portion of the REO has not been met in full, DG biomass resources should be compensated for the extra benefit that this offers to the utility. In our initial comments we offer several suggestions for how this might be done.

DG customer obligation to certify their generator as renewable should be minimal

The utilities' suggestion that a DG generator must be certified to receive a renewable credit holds DG to a higher standard than a utility's own renewable energy facilities. In an information request to the Regulated Electric Utilities,[9] each utility was asked to describe the process for certifying its own, or purchased, renewable generation that the utility used to meet the green pricing program or the REO, and the costs associated with the certification. None of the utilities reported using any third-party certification, nor any certification at all for meeting the REO, although the Department of Commerce is required to certify that power used to meet a utility's green pricing program is eligible under the program. However, a large part of the Department's inquiry concerns making sure that a renewable power supply is only sold once to retail customers, a burden which should be on the utilities, not the DG generators.

The main concern appears to be whether or not a renewable DG facility would qualify as renewable under state statutes. If deemed necessary, a one-page standard form that is submitted with the rest of a DG customer's application should be sufficient to make this determination.

[9] "The Minnesota Project Utility Information Request (1-9)", submitted to the Commission's service list 3-28-03 by Carl Nelson.

8. Emission credits

The DG Coalition agrees with the Department's position that DG customers should receive emission credits for both tradable and non-tradable emissions, to the extent that those emissions are lower than the emissions for the next unit the utility plans to construct. Market values would be used to value tradable emissions, and non-tradable emissions would be valued at the Commission's established externality values. However, the market for the non-tradable emissions will emerge. The concept is being extended to the CO_2 credit by the Chicago Climate Exchange. CO_2 credits therefore will be important in the future.

In their initial comments, the Regulated Electric Utilities argued that since the generator and not the utility is responsible for the one emission that is traded currently, SO_2, utilities should not give a credit to a DG customer for SO_2. In addition, they disagreed with the Department that there should be a credit for non-tradable emissions. The utilities' rationale was externality values are embedded in the avoided cost of energy, and further, that the externality values are not something that the utilities actually pay for on a kWh basis, but a tool within the resource planning process.

DG generators are excluded from the resource planning process, and thus should receive emission credits set at the externality values

Externality values for six pollutants, on a dollars per ton basis, have been set by the Commission based on the economic value of the health and environmental damage they cause.[10] These values are then used in the resource planning process to help choose between alternative resource options. Externality values are applied to the costs of alternative resource options, and if the least cost option becomes a higher cost option after the application of the externality values, the utility must choose the lower-emission resource, even though the cost to the utility might be higher. Thus the utilities argument that the externality values are embedded in avoided costs, because if a utility must choose a higher cost resource because of lower environmental costs, the utility's avoided cost would increase.

[10] MN PUC Docket No. E-999/CI-93-583. Originally a value for SO_2 was set, but when SO_2 became tradable, the externality value went to zero.

However, in response to an information request to the regulated utilities, not a single utility could site a case where avoided costs have been increased due to application of externalities in the resource planning process.[11] Furthermore, even if the avoided costs were higher due to the application of externality values, for DG this misses the point of having the externality values. Higher avoided costs equally benefit clean DG and dirty DG. There would be no incentive or preference given to clean generation options, as was the intent of the externality law.

The DG Coalition urges the Commission to adopt emission credits for DG customers based on the externality values for lower emissions. Emission factors should include the value of the thermal energy for combined heat and power applications.

9. Streamlined Documentation for Smaller DG Projects

The DG Coalition is supportive of an ongoing collaboration to streamline and simplify the interconnection documentation and requirements for smaller, pre-certified DG projects (likely 2MW and under). The development of these super-streamlined procedures should include input from a variety of interested parties. The DG coalition would respectfully suggest that the Commission include a timeline and deadline for these super-streamlined documents to be developed.

[11] "The Minnesota Project Utility Information Request (1-9)", submitted to the Commission's service list 3-28-03 by Carl Nelson. Responses to the question on higher avoided costs due to application of externality values received from Minnesota Power, Otter Tail Power, and Alliant Energy. Xcel Energy declined to answer.

Conclusion

The DG Coalition respectfully requests that the Commission take strong actions in this docket to promote DG development in Minnesota, through adopting the recommendations we have outlined above. We look forward to continued participation in the development of DG policy.

Please contact the DG Coalition representatives if you or your staffs have any questions:

Rafi Sohail	CenterPoint Energy Minnegasco	(612) 321-4779
Larry Schedin	on behalf of Hennepin County	(612) 370-1319
John Bailey	Institute for Local Self-Reliance	(612) 379-3815
Adam Sokolski	Izaak Walton League of America, Midwest Office	(651) 646-1446
Stephen Korstad	Korridor Capital Investments LLC	(651) 765-0300
Laura Bordelon	Minnesota Chamber of Commerce	(651) 292-4682
John Jaffray	Prairie Gen	(612) 334-9643
Carl Nelson	The Minnesota Project	(651) 645-6159