

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

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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

March 21, 2003

**COMMENTS OF THE DG COALITION**

**BACKGROUND**

On August 20, 2001, the Minnesota Public Utilities Commission (Commission) issued its Order Initiating 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 Work Groups, headed by the Minnesota Department of Commerce, to draft documents and guidelines for the distributed generation interconnection standards and tariffs.

On February 3, 2003 the Minnesota Department of Commerce (Department) filed its Final Report on Distributed Generation Technical Standards and Tariff (Final Report).

On February 18, 2003 the Commission issued a Notice that acknowledged the receipt of the Final Report and Establishment of comments periods.

The Distributed Generation Coalition (DG Coalition) respectfully offers these initial comments for consideration:

## **INTRODUCTION**

The following are the consolidated comments of the DG Coalition, a group of organizations representing a wide range of energy interests. 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 Work Groups meetings and summarizing the outcome in the Final Report on Distributed Generation Technical Standards and Tariff (Final Report).

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  
The Minnesota Project

The Minnesota Public Utilities Commission's (Commission) work on distributed generation galvanized this diverse group of organizations to work together and ensure that the current unnecessary barriers limiting development of distributed generation (DG) are dismantled as

much as possible. The DG Coalition is a unique partnership. While many parties in the DG Coalition have been at odds with each other over energy policy directions in the past, bringing distributed generation and its benefits to Minnesota is a common goal for all. Over the past seven months, the DG Coalition has met about two dozen times apart from our regular full work group meetings to discuss and formulate a unified vision of promoting distributed generation in Minnesota per the Commission's directives.

## **DG TECHNICAL STANDARD ISSUES**

Mr. Ken Wolf, chair of the Technical Work Group, formed a sub-group of technical experts to draft three key elements:

1. Electric requirements for interconnection
2. Application procedural rules
3. Interconnection, operation and maintenance agreement

Because of time limitations and the highly technical content, the February 3, 2003 report to the Commission includes only the Electrical Requirements for Interconnection, a highly technical document which recognizes and integrates various efforts of the IEEE, NARUC, FERC, Texas, California and others. It is our feeling that the draft set of technical interconnection requirements in Mr. Wolf's report are fair, to the extent that they are complete. Our primary concerns regarding technical issues are related to issues that have not yet been finalized. These include: developing standard applications, a standardized review process, and insurance for DG projects.

It is our recommendation that Mr. Wolf's sub-group continue their work and produce drafts of the application procedural rules and the interconnection, operation and maintenance agreement. All interested parties should be allowed to review these drafts in the same manner as the electrical requirements for interconnection. After such review and revision the drafts should be submitted to the Commission in a timely manner.

Another issue that neither the Technical nor the Rate work group addressed comprehensively is responsibility and fee structure of all interconnection studies. We recommend that Mr. Wolf convene the entire work group (not just the sub-group) to address this issue.

## **DG TARIFF ISSUES**

The collaborative meetings have allowed a valuable forum to raise and discuss critical issues to shape the distributed generation (DG) tariffs in Minnesota. Although the DG Rate Work Group reached general consensus on some key items, the unresolved issues still impose onerous obstacles to promote DG in Minnesota. The following discussion outlines the unresolved items and highlights the DG Coalition's argument to mitigate those barriers.

### **Availability and Qualification**

#### DG Definition

The Department's definition of DG in the Final Report says that the DG customer must be parallelly interconnected to the utility distribution system<sup>1</sup>. It is important to clarify that the interconnection requirement section shows that a DG unit not connected in parallel to a utility system must serve load via a properly designed transfer switch if the load is also to be served by the utility for some of the time. This is called a "break before make" transfer and is subject to the interconnection rules. The regulated electric utilities define DG as electrical generation facilities of 10 MW of capacity or less connected to a utility through a Point of Common Coupling<sup>2</sup>. The DG Coalition suggests that further clarification will be helpful to identify when a facility meets the tariff requirements.

Examples of facilities that need further clarification are facilities whose total requirements exceed the 10 MW limit, but have multiple points of delivery, each of which is about 10 MW. The DG Coalition would recommend that as long as the DG installation produced 10 MW or

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<sup>1</sup> 'Final Report on Distributed Generation Technical Standards and Tariffs' by the Minnesota Department of Commerce, Rates section – Part III.A, dated February 3, 2003.

<sup>2</sup> 'Establishing the Generic Standards for Utility Tariff Interconnection and Operation of Distributed Generation Facilities' consolidated comments of the regulated electric utilities, page 18, December 3, 2001.

less per delivery point (or point of common coupling), the DG Tariff could apply. Another example would be a facility whose total capacity is less than 10 MW and the host utility serves the facility with multiple lines and intra-site utility-owned lines and equipment. This customer could be prohibited from maximizing the benefit of a 10 MW DG facility unless the use of intra-site wheeling was expressly allowed.

#### DG Ownership

The DG can be owned by end-use customers, the utility, third parties, or a hybrid ownership. The DG Coalition strongly supports the Department's position that there is no need to restrict the type of DG ownership as long as the ownership of the DG facilities is clearly identified. The Department wrote a letter to this affect, dated March 18, 2003, in response to Commission's Notice regarding Part III, B.1 of the Final Report. We believe that this should settle the matter.

#### Merchant Plant

In the same March 18, 2003 clarification letter, the Department recommends that the DG tariff should not be available to a Merchant Plant or an IPP since the DG tariff is designed to encourage retail customers to offer DG service.

The DG Coalition believes that DG tariff should be flexible and include a Merchant Plant or an IPP. As long as the DG customer (or a third party) is not selling power at retail level, which requires an open access tariff, there should not be any discrimination on how the customer elects tariffs or negotiates outside the tariff rates.

#### DG Location

Most of the focus of the Rate Work Group on tariffs addressed DG projects that would be built on the site of an existing utility customer. The issue of how to treat DG projects that are not sited at an existing utility customers' physical location was not addressed in detail. A clarification is needed to determine what constitutes 'on-site' in terms of DG location. Currently, the Department summarizes the work group discussion to be at the 'same site' in Part III.B.1 of the Final Report. The DG Coalition argues that the DG can be physically

located within customer's facility or outside the property boundary. The adjacent unit should be able to deliver to all points within a plant complex over utility owned distribution as long as the third party owner is not technically selling electricity at retail within the site.

We see multiple scenarios where a customer of a utility would build a DG facility that would not necessarily be located on the customer's property. For instance, a customer may decide to lease the adjacent property to install the DG if it has limited room in its facility. A manufacturing plant owner pays a lease payment plus fuel to the third party. A city may elect to provide property tax incentives to promote the local growth. Another example is small-distributed wind projects, which will be sited in rural areas of Minnesota away from buildings, homes and businesses. While the wind turbines may not be sited adjacent to the owner's energy using facility, the electricity will not be sold at retail, and therefore, will not violate the spirit of the DG tariff. Of course, the wind project owner, and all DG projects have the ability to negotiate directly with the utility outside the tariff.

### **Demand Ratchet**

The DG Coalition strongly urges the Commission to disallow the electric utilities from applying the demand ratchet if a customer installs DG at its facility. Although the issue was raised briefly, the demand ratchet was not discussed in detail during the Rate Work Group's discussions. The demand ratchet represents one of the significant barriers to promote DG in Minnesota. The demand ratchets are minimum billings for demand brought forward from the usage in prior months, regardless of the actual demand of the facility in the given month. It applies to those customers who drop their peak demand (kW) load below 50% of the current level, and it is based on the preceding 11 months.

The following example illustrates the impact of the demand ratchet. Assuming a customer with 6 MW constant monthly peak demand load installs 5 MW of DG, the actual new peak demand should register 1 MW (6 MW – 5 MW of DG) on electric utility's meter. However, the electric utility will charge the customer based on the adjusted demand of 3 MW using the 50% rule for the next 11 months until the new demand is established. Furthermore, this customer would have to elect standby charges and pay added monthly reservation fees.

Because this customer is changing its basic use profile and has notified the utility by electing standby or other options, the demand ratchet amounts to double charging the customer for the same capacity for the first 11 months.

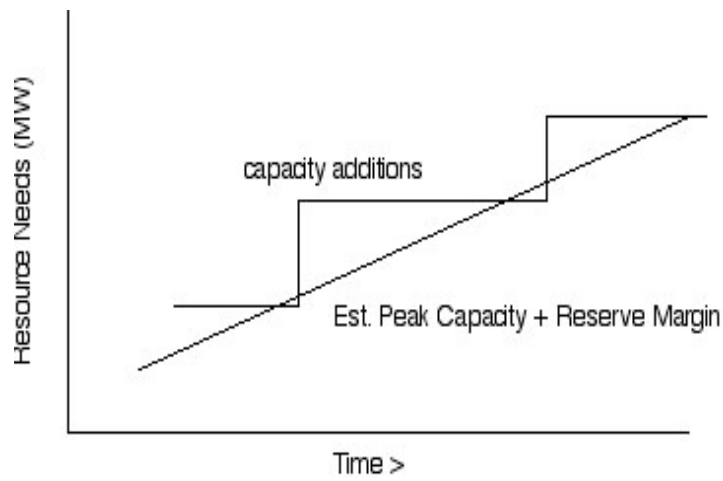
### **Avoided Capacity Costs**

The Department outlines the Rate Work Group's discussion and its recommendation in Part III.F.2 of the Final Report on how to calculate avoided cost payments for capacity. This issue was controversial in work group discussions but the parties did come to a place of relative agreement on this issue as is described by the Department.

The DG coalition 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, whether intentional or not. One of the most salient examples of this is in the calculation of avoided capacity costs.

The current system of resource planning and energy acquisition can be visually depicted as a staircase (see chart 1). There is a line of projected peak demand (plus reserve capacity requirements) that increases over time. The utility will add resources in large blocks to stay above that line; a typical utility addition might be hundreds of megawatts. This results in lengthy periods of time where a utility can claim that they have no need for new capacity. Under the department's proposed plan, DG projects will not be eligible for avoided capacity payments, or at the least, the payments would be discounted for a number of years.

**Chart 1: The step or block approach to energy resource additions by utilities.**



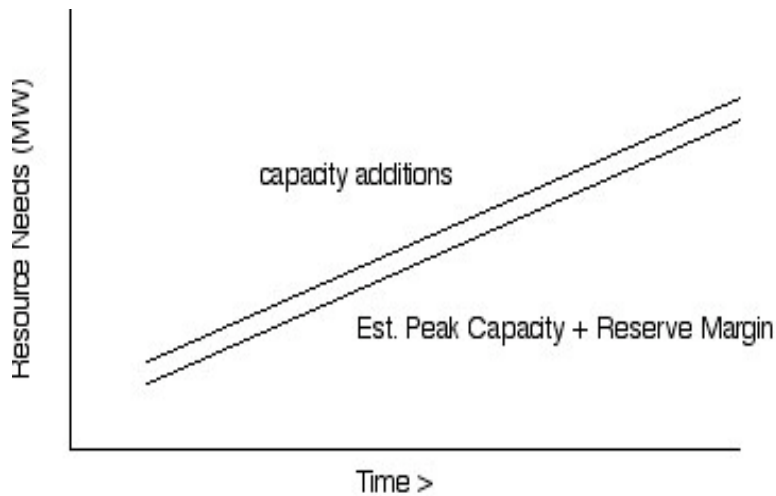
The DG Coalition views this as discriminatory towards DG, because had the utility been adding energy resources on a much smaller scale (several or tens of megawatts at a time instead of hundreds), their supply curve would more closely resemble their demand curve, and they would always have need for new capacity that could be supplied by DG (see Chart 2). One might argue that the utility does not add capacity in such small increments because it would be cost prohibitive; large projects have economies of scale that results in a lower cost per kWh than a DG project. However, since the utility's payments to the DG owner for energy and capacity would be based on the utility's actual avoided costs and not on the DG owner's cost of building and operating the DG resource, it would not cost the utility a penny more to add non-utility DG than it would a traditional resource. In fact, under traditional resource planning, there are significant periods of time when the utility has excess capacity above and beyond what it needs to meet demand plus reserve requirements. This represents a cost to the utility in the form of under-utilized assets which must be sold into the market. If the utility used DG resources to perfectly match the demand, there would be no periods of excess capacity for the utility as we see under traditional resource planning (Chart 1), and the utility would actually be operating more efficiently.

The Department recommends that if the utility establishes a need for capacity additions in its resource plan, DG owners should always be paid for capacity, but the payments should be



discounted from the date when the utility actually needs the capacity. Under this plan, a DG owner would practically never get a full capacity payment, because the payment would depend on when the utility was going to make a capacity addition that is included in their resource plan. The year before the capacity addition, the DG owner would get nearly full payment, but the following year after the addition was made, it would again be discounted for when the utility planned on the next addition, perhaps 5 to 10 years later. This discriminatory practice should not be the basis for setting DG capacity payments. 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. We do not disagree with discounting for the length of the contract, as the Department also suggests.

**Chart 2: The Distributed Generation approach to energy resource additions by utilities.**



### **Standby Rates**

We agree that reservation 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 true costs. Although the Rate work group did make some progress in certain standby fee related issues, the current reservation fee structure as outlined in the Department's Final Report will continue to represent a major barrier for customers considering DG.

The Rate work group assumed the existing standby reservation fee structure of the fixed dollar per kW per month is valid. We recognized that detailed accounting and justification of the charges included in the standby fee would require a separate docket proceeding, which was not allowed by the limited timeline of this docket. Therefore, most of the arguments centered on providing credits against the existing reservation fees structure. The DG Coalition recommends that the Commission explore initiating a separate standby charges docket to provide alternative reservation fee structure options if the generic interconnection docket does not fully mitigate the existing standby charge barriers.

For example, Xcel's standby rate is claimed to be a firm standby rate. Unfortunately, it is not a proper firm standby rate because any standby use during a control period is priced at a market penalty rate. A proper standby rate should charge a predetermined rate for use during control periods based on utility capacity reserved in advanced based on the diversified standby needs of all DG customers as a group.

#### Maximum Size to Avoid Standby Charge

The DG Coalition strongly supports Department's recommendation to exempt DG projects of 100 kW or less from any standby charges. This modest proposal will allow some DG projects on the cusp of economic viability to move forward without putting undue financial burdens on other ratepayers. Standby fees are considered one of the biggest roadblocks to distributed generation and this is a clear policy that can remove that barrier for smaller projects, promote DG and ensure that other customers are not unnecessarily burdened. At the same time, utility will not be unduly burdened by this requirement.

Noticeably, California has temporarily waived the standby and supplemental charges for DG under 5 MW. With the exception of the diesel generators, DG going into operation by June 2003 is exempt from standby charges for at least the next ten years<sup>3</sup>.

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<sup>3</sup> California Public Utilities Commission, "Interim Decision Adopting Standby Rate Design Policies" (Rulemaking 99-10-025, decision 01-07-027) July 12, 2001.

### Firm and Non-firm Standby Service

The DG Coalition supports the policy to apply discounts on the generation and transmission portions in the standby reservation fees as outlined in the Department's Final Report. The generation and transmission portions in the firm standby rates are recommended to be discounted at 82 – 85%, and non-firm standby rates are recommended to be discounted at 100% level.

However, we argue that similar discounts can be applied to the distribution portion of standby reservation fees. The distribution portion of the reservation fee should be itemized as two distinct parts:

- Non-bulk (local) Distribution: Includes wires, metering and equipment, and connection of the individual site to the utility system. Most of these are fixed costs where the discount or credit may be minimal.
  
- Bulk Distribution: Includes terminal, substations, and other equipment used to move power into the distribution grid. The DG Coalition believes that DG relieves the load capacity of the bulk distribution at the same levels to the reserve margins of the generation and transmission levels and should result in a similar discount.

We recommend the bulk distribution portion of the reservation fee should be discounted at 82 to 85 % level under firm standby reservation fee, similar to generation and transmission because the distribution facilities will be freed up to serve other load. A 100% discount is recommended under the non-firm standby reservation fee structure.

### Physical Assurance:

A physical assurance customer is a customer who agrees not to require standby services and has a mechanical device to insure that standby service is not taken. The DG customer agrees

to provide physical control to remove load if its DG system is not operating. We strongly endorse the physical assurance option.

The Department summarizes the work group discussion that a physical assurance customer would have an option either to pay up-front for stranded distribution facilities that it will not use or to pay distribution services (both bulk and non-bulk), through standby charge, for the entire amount of load.

The DG Coalition argues that the entire distribution charges portion in the standby reservation fee should not be considered as the total stranded distribution costs. The DG Coalition argues that the bulk distribution portion of the standby reservation charges should be 100% discounted because the utility will be able to use the assets to serve other loads.

If a customer elected to pay the up front stranded costs, only the non-bulk portion of the distribution service should be charged. The stranded costs should be based on the current book value of the distribution portion system instead of the replacement costs. The electric utility will continue to own and maintain the portion of that distribution system even if the DG customer pays off the stranded costs.

If the Commission chooses not to subdivide distribution charges into bulk and non-bulk, then the DG Coalition suggests that to the extent the electric utility benefits by reselling those portions of the distribution system identified as serving the DG customers, a credit, as a reimbursement of payments, should be given back to the DG customer.

In addition, if a customer elected physical assurance on a new DG load (i.e. green-field or capacity addition), the standby charges should be zero including the entire distribution portion, bulk and non-bulk, since new load is not a stranded asset. The utility does not need to build either facilities related or peak demand related distribution infrastructure to serve that customer, thus avoiding fixed standby distribution costs.

## **Distribution Credits**

On page 12 of Department's Final Report, there is a discussion of Distribution constrained credits. Section 2b states:

Each utility should publish on the Internet its annually conducted distribution capacity planning study that identifies capacity needs, upgrades and load growth on area distribution feeders.

The DG Coalition strongly endorses this position. It is very important that information on where the distribution system is in need of support is easily accessible and in the public domain. Disclosing this type of information in a clear, understandable format will allow DG project developers to target DG to locations where it will benefit the distribution system the most. This information will promote and help to ensure that the desired outcomes of increased distributed generation in Minnesota are met. The Commission should establish a "date certain" when each utility must update their information on the Internet.

## **Diversity Credit**

The DGs require less reserve on a diversified basis than bigger units when applying the standard simulation process used by utilities. This stranded method applies a threshold of risk of "once in ten years" that generation cannot meet load within MAPP. The key inputs are unit size and forced outage rates. Smaller units and smaller forced outage rates decrease reserve margins. Since DG units are smaller than utility units and operate at a higher availability factor, this family of units requires less back up capacity than a typical utility per MW of installed capacity. We estimate that 8% reserve allocation should be used either to recognize the proper amount of utility generation assigned to back up DG customers or to be recorded as a credit from the utility prescribed tariff.

## **Renewable Energy Credit**

Minnesota policymakers have recognized the necessity, for human health and environmental reasons, of transitioning Minnesota's electric generation to renewable energy, and have set in statute several initiatives to accomplish this. Because they require utilities to generate more renewable energy, these laws create a market value for renewable energy above and beyond its energy value. It is the position of the DG Coalition that DG customers providing renewable energy should always receive a renewable energy credit to compensate them for the value that they are providing to utilities. Thus the renewable energy credit is not a subsidy, but a direct reflection of the economic value the DG customer is providing to the utility by adding green energy to their portfolio.

The Department in the Final Report agrees with the idea of a renewable energy credit, to the extent that the payment of a DG credit "is based on the principle of setting rates at avoided costs." That is, to the extent that a utility must procure green power, and pay extra for it, the renewable credit should be given to the DG customer. The question to be determined, in the Department's view, is "whether it is reasonable for utilities to pay a credit for renewable power ... even if the utility does not need the green power."

We argue that current law ensures that utilities will always have a continual demand for adding renewable energy generation to their portfolios, and thus there should always be a renewable energy credit. There are three main Minnesota laws affecting utilities' purchase of renewable energy:

1. Renewable Energy Objective (MN Stat. § 216B.1691). Requires all utilities in Minnesota to make a "good faith effort" to generate or purchase an increasing percentage of their energy from renewable sources (one percent per year starting in 2005), to at least 10 percent of their total portfolio by 2015, including one percent generated from biomass.
2. Green Pricing (MN Stat. § 216B.169). Requires all utilities in Minnesota to initiate programs that allow their customers to purchase renewable energy (as well as low-emissions DG). As more customers subscribe to the green pricing program, utilities will have a need to add renewable energy to their generation options.

3. Xcel Energy Wind and Biomass Mandate (MN Stat. § 216B.2423 and 216B.2424). With the determination of the viability of building wind power, requires Xcel Energy to build or purchase 825MW of wind, and 125 MW of biomass. Xcel is in the last stages of fulfilling it's biomass mandate, but is only about half finished with its wind mandate.

Collectively, these laws ensure that utilities will have a continuous need to add renewable energy to their generation portfolio. In addition, there is movement at the state and federal level to enact policies that would increase the need for utilities to further increase their commitment to renewable energy. The federal regulation of carbon dioxide, for instance, could make current fossil sources un-economic and drive utilities to further hasten their acquisition of renewable energy resources.

The DG coalition acknowledges that in a particular year, assuming the Renewable Energy Objective (REO) is rigorously followed, a utility can claim that they have no need for renewable energy in that year and thus a credit is not justified by the strict principle of avoided cost. The DG coalition believes that this reasoning would be discriminatory practice towards DG generators. By definition, a DG generator under the DG tariff does not participate in the utility's resource planning process by which it meets its REO. Instead, they must rely on the market signal of the utility purchase price (including credits) to determine if a project is economic or not.

In order to ensure proper market signals for doing renewable DG, a prospective DG generator should not face uncertainty over whether or not they will receive the renewable credit just because there is a small amount of time when the utility can claim they have no demand for renewable energy. In reality, this time frame is likely to be short; a small fraction of the length of a DG project. Even if a utility has met their REO and all demand for their green pricing program in a particular year, by the next year or the following they will need to add more. Thus in order to ensure proper market signals for DG, and in the interests of promoting DG per legislative intent, a DG generator should always receive the DG credit.

The remaining question before the commission is how to set a price for the renewable energy credit. The price should reflect the additional cost that the utility would incur to add renewable energy to their generation portfolio. Generally this will be the least-cost renewable energy resource. Because the REO must be met partially with biomass, and biomass is generally more expensive than wind, the credit for renewable biomass should reflect this until the biomass portion utilities' REO is met.

For setting the DG renewable energy credit price for non-biomass energy, the DG coalition recommends the price be based on the price premium that a utility charges for participation in its green pricing program. Although the renewable energy from a DG project could be used to meet the REO or other requirements the utility may have as well as a utility's green pricing needs, the green pricing program offers a ready calculation of the actual incremental cost to the utility to procure renewable energy.

For setting the credit price of biomass energy, it is less clear how to proceed, as there is no existing price-setting process that we are aware of that the credit price could be pegged to. In order to set a biomass credit that is closest to the actual cost to the utility to procure biomass, we recommend the following. The DG would have a choice of default price, or using the last price in term of the given utilities latest externally audited and accepted competitive bid or resource acquisition process or activity. If a utility has existing bids for biomass sources (for example, bids collected through their Integrated Resource Plan), these could be used as a basis for the biomass credit. If the utility does not have existing bids for biomass, the Department of Commerce would evaluate recent bids for biomass within Minnesota in order to set a default price for the whole state. For example, Xcel Energy has had to contract for 125 MW of biomass, and other biomass projects have been funded through the Renewable Development Fund. In no case should the biomass credit be lower than the credit for non-biomass sources, since if this were the case, the biomass resource could simply count towards credit for general renewable energy.

## **5. Emission Credits:**



We strongly support the policy of providing both the tradable and non-tradable emission credits as outlined in the Final Report. DG projects should be eligible to receive a credit for their impact in lowering utility system emissions. Although using the utility's avoided emission costs is an acceptable option with the lack of market for the non-tradable emissions, customers should have options to explore other markets if the trading emerges for those emissions. We also argue that the operational efficiencies of a given project will be accounted for within the framework of the emissions credit as long as the emissions credit is based on the total energy output of a given DG project. So, in the case of the CHP project, both the electric and thermal output should be included in the calculation of emissions

### **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:

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