February 3, 2003

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Final Report of Work Groups Regarding Distributed Generation**
Docket No. E999/CI-01-1023

Dear Dr. Haar:

On June 19, 2002, the Minnesota Public Utilities Commission (Commission) issued an Order regarding Distributed Generation for all electric utilities in Minnesota. The Order requested the Minnesota Department of Commerce (Department) to organize and lead two work groups: a technical work group and a rate work group. The technical work group is to recommend uniform interconnection guidelines for distributed generation, while the rate work group is to develop guidelines to ensure that prices for electric services provided by the electric utility are reasonable and nondiscriminatory while prices charged for power provided by the generator to the utility reflect the value of power.

The Commission also directed the Department to file reports on progress of the work groups. We filed the first report on September 19, 2002, and the second report on December 19, 2002 This is the final report due February 3, 2003. We are providing copies of this report to the docket service list.

It is our recommendation that the Commission establish a timeframe for comments and reply comments from interested parties.

We are available to answer any questions the Commission may have on these reports or the work groups.

Sincerely,

KEN WOLF
Reliability Administrator

EILON AMIT
Rates Analyst

KW/EA/jl
Attachment

REPORT ON DISTRIBUTED GENERATION TECHNICAL STANDARDS AND TARIFFS

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

BY THE

MINNESOTA DEPARTMENT OF COMMERCE

FEBRUARY 3, 2003

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DISTRIBUTED GENERATION TECHNICAL WORK GROUP

REPORT TO THE PUBLIC UTILITIES COMMISSION
February 3, 2003

Docket No. E999/CI-01-1023

I. INTRODUCTION

On August 20, 2001, the Public Utilities Commission (Commission) issued an Order initiating the instant Docket. The purpose of this Docket is to establish generic standards for utility tariffs for interconnection and operation of distributed generation facilities. The Commission issued this Order to comply with Minnesota Laws 2001, chapter 212, codified in relevant part at Minnesota Statute § 216B.1611, subd. 2 of that statute states:

> (a) The commission shall initiate a proceeding within 30 days of the effective date of this section, to establish, by order, generic standards for utility tariffs for the interconnection and parallel operation of distributed generation fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than ten megawatts of interconnected capacity. At a minimum, these tariff standards must:
>
> (1) to the extent possible, be consistent with industry and other federal and state operational and safety standards;
>
> (2) provide for the low-cost, safe, and standardized interconnection of facilities;
>
> (3) take into account differing system requirements and hardware, as well as the overall demand load requirements of individual utilities;
>
> (4) allow for reasonable terms and conditions, consistent with the cost and operating characteristics of the various technologies, so that a utility can reasonably be assured of the reliable, safe, and efficient operation of the interconnected equipment; and
>
> (5) establish: (i) a standard interconnection agreement that sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system; and (ii) a standard application for interconnection and parallel operation with the utility system.
>
> (b) The commission may develop financial incentives based on a public utility's performance in encouraging residential and small business customers to participate in on-site generation.

The Commission's June 19, 2002 Order directed the technical work group to:

> *… draft documents and guidelines for tariffs so that a person interested in developing distributed generation can apply for interconnection to any electric utility in the state with the expectation that the requirements for making interconnection –*
> 1) *are uniform across electric utilities,*
> 2) *are clear, concise, understandable and easy to follow,*
> 3) *impose obligations only if they are reasonably necessary for the safety of persons and equipment or for the reliable operation of the electric distribution system,*
> 4) *require no more than the minimum studies necessary for the safe and reliable interconnection of the unit with the electric distribution system, and*
> 5) *provide for conducting any necessary studies quickly and efficiently.*

II. BACKGROUND

Previous work group activities were summarized in the Department's interim reports to the Commission on September 19 and December 19, 2002. The Department recognized that the technical expertise on the work group varied considerably and that discussions by the full work group were going to be challenging. A smaller subgroup, as described in the December 19, 2002 interim report, was formed and met weekly through January 2003. Numerous comments and revisions produced a draft Technical Requirements document supported by the subgroup. The draft was distributed to the full work group for review prior to its final meeting on January 28, 2003, attended by 19 interested persons. Additional comments were received during and after the meeting, and a final proposed Technical Requirements document was prepared. It is attached to this report.

III. PROCESS

Significant movement in the discussion on technical requirements was achieved in late September 2002 when the International Electrical and Electronics Engineers (IEEE) reached a review milestone in the development of a Standard for Distributed Resources Interconnected with Electric Power Systems, referred to as IEEE P1547/D10. The standard provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the electric power system interconnection. The Department's subgroup was able to incorporate the national standards into its document to ensure alignment of state and national standards.

The technical work group determined that three products were needed to achieve the Commission's expectations:

Technical Requirements........ The technical devices, systems, procedures, etc. that are required for the interconnection of a ≤ 10 MW generator to a utility system.

Standard Procedures .... The process from application to final agreement, including timelines for review and response.

Standard Agreement .... The instrument obligating a generator and a utility to interconnection and operating requirements.

The work group focused on the technical requirements task and has not completed discussions with the work group on standard procedures and agreements. The Federal Energy Regulatory Commission (FERC) has developed expedited procedures for small generators of 20 megawatts or less. Furthermore, the FERC's rulemaking will develop detailed, simplified procedures and agreements to allow for quick, inexpensive, and simple interconnection for small generators up to and including 2 megawatts and a different procedure and agreement for units over 2 megawatts through 20 megawatts.

Participants in the work group believe that the standard procedures and agreements developed by FERC have a high probability of serving as a relatively complete platform for use by all states. There has already been a great deal of consensus in comments by state regulators, generators and electric utilities. The FERC expects to issue a final rule on a ≤ 20 megawatt standardized interconnection procedure and agreement near the end of March 2003. The Department believes it is prudent and efficient to reap the mutual benefits of this national effort. Most of the substance of the FERC rulemaking should be applicable to Minnesota's interest in standardizing interconnection to the state's electric distribution system. States that have already developed generic standards are expected to revise them to comport with the FERC standards.

The Department believes it can characterize the work group's collective position on the Technical Requirements to be supportive. The document offers a reasonable balancing of obligations between the generator and the utility. During the discussions, there was significant enhancement of the work group's knowledge about the technical potential for small-scale generation interconnection. Perspectives from both the generator and utility interests have been expanded by experience in recent years with projects requiring interconnection. Those perspectives, and the mutual interest of all to share knowledge, set the framework for significant accommodation of changes that allowed general support for the proposed Technical Requirements document. Participants understand that there will be an opportunity for additional comment to the Commission before adoption.

In developing background for its work group, the Department reviewed initiatives by other jurisdictions to develop generic interconnection standards. The electric utility group prepared a comparison matrix, which is included with this report.

The Department submits its proposed "Requirements for Interconnection of Distributed Generation" as partial fulfillment of the Commission's Order. It is not represented as a consensus product, but is believed to have strong support from the work group. The Department recommends that the Commission provide additional opportunity for public comments and reply comments.

The Department will continue to convene the subgroup to focus on national generic standards initiatives relating to interconnection procedures and agreements to develop a broadly supported set of standards for these two elements. This is expected to take approximately 60 to 90 days, depending on the FERC schedule for completing its work on these two issues.

Comparison of Interconnection Requirements

1/28/2003

	Utility 12/3/01 Filing	IEEE Rev 10	Texas	NARUC	FERC	Wisconsin Draft 5.95	California	Proposed Minnesota Standard Page #
Technical Standards								
Electrical Code Compliance								
Installer must meet codes and permit requirements	Yes	--	Yes	--	Yes	Yes	Yes	Yes
Open Transition	Yes	--	--	--	--		--	Yes
Mechanical Interlock	Yes	--	--	--	--		--	Yes
Describes Protective Elements Required	Yes	--	--	--	--	--	--	Yes
Quick Closed Transition Transfer Switch	Yes	Some	Yes	--	--	Yes	Yes	Yes
Mechanical Interlock	Yes	--		--	--	--	--	Yes
Describes Protective Elements Required	Yes	--	Yes	--	--	Yes	Yes	Yes
Closed Transition Transfer Switch (Soft Loading)	Yes	Some	Yes	--	--	Yes	Yes	Yes
Describes Protective Elements Required	Yes	Some	Yes	--	--	Yes	Yes	Yes
Extended Parallel Operation	Yes	Yes	Yes	--	Yes	Yes	Yes	Yes
Describes Protective Elements Required	Yes	Yes	Yes	--	--	Yes	Yes	Yes
Inverter Connection	Yes	--	Yes	--	--	Yes	Yes	Yes
Describes Protective Elements Requred	Yes	--	Yes	--	--	Yes	Yes	Yes
Describes Inverter Certification Requirements	Yes	--	Yes	--	--		Yes	Yes
Interconnection Issues and Requirements								
Visible Disconnect Requirement	Yes	--	Yes	--	--	Yes	Yes	Yes
Grounding Requirements	Yes	Yes	--	--	--	Yes	Yes	Yes
Maximum Single Phase Generation Size			50kW			--	20kVA	40kW
Operating Limits								
Voltage	Yes	Yes	Yes	--	--	Yes	Yes	Yes
Establishes Maximum Voltage Dip Magnitude Level		5%	3%				--	4%
Frequency	Yes	Yes	Yes	--	--	Yes	Yes	Yes
Harmonics	Yes	Yes	Yes	--	--	Yes	Yes	Yes
Interference	Yes	--	Yes	--	--		Yes	Yes
Islanding	Yes	Yes	--	--	--		Yes	Yes
Power Factor requirements				--	--	>90-100%	>90%	Yes
Feeder Penetration Percentage Issues	--	Yes	Yes	--	--		Yes	--
Deals with Issues involved with Spot Networks	--	Yes	Yes	--	--	Yes	Yes	--
Generation Metering, Monitoring and Control								
Describes Metering Requirements	Yes	--	--	--	--	Yes	Yes	Yes
Describes Monitoring Requirements	>1MW	>250kW	>2MW	--	--	Yes	>250kW	>1MW
Protective Relaying								
Describes relaying standards	Yes	Yes	Yes	--	--	--	Yes	Yes
Provides protective one-lines	Yes	--	--	--	--	Yes	No	Yes
Testing Requirements								
Describes required tests for installations	Yes	Yes	--	--	--		Yes	Yes
Allows Pre-Certified or Type Tested equipment	Yes	Yes	Yes	--	--	Yes	Yes	Yes
Defines"Pre-Certified"			Yes			Yes	Yes	Yes
Requires commisioning tests	Yes	Yes	--	--	Yes	Yes	Yes	Yes
Discusses Periodic maintenance Testing	Yes	Yes	--	--	--			Yes
Interconnection Review Process								
Provides Review Process Flow Chart	Yes	--	Yes	Yes	--	Yes	Yes	Reviewing
Provides standard process	Yes	--	Yes	Some	--	Yes	Yes	Reviewing
Provides standard costs for engineering studies (See Tab	--	--	Yes	--	--	Yes	Yes	Reviewing
Provides Standard Application	Yes	--	Yes	Yes	Yes	Yes	Yes	Reviewing
Dispute Resolution Procedures	--	--	Yes	Reviewing	Yes	--	Yes	Reviewing
Provides Interconnection Agreement	Yes	--	Yes	Yes	Yes	Yes	Yes	Reviewing
Insurance Requirements (Seet Table 3)	Yes	--	Yes	Yes	Yes		--	Reviewing

PROPOSED
STATE OF MINNESOTA
REQUIREMENTS FOR INTERCONNECTION OF DISTRIBUTED GENERATION

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Foreword

Electric distribution system connected generation units span a wide range of sizes and electrical characteristics. Electrical distribution system design varies widely from that required to serve the rural customer to that needed to serve the large commercial customer. With so many variations possible, it becomes complex and difficult to create one interconnection standard that fits all generation interconnection situations.

In establishing a generation interconnection standard there are three main issues that must be addressed; Safety, Economics and Reliability.

The first and most important issue is safety; the safety of the general public and of the employees working on the electrical systems. This standard establishes the technical requirements that must be met to ensure the safety of the general public and of the employees working with the Area EPS. Typically designing the interconnection system for the safety of the general public will also provide protection for the interconnected equipment.

The second issue is economics; the interconnection design must be affordable to build. The interconnection standard must be developed so that only those items, that are necessary to meet safety and reliability, are included in the requirements. This standard sets the benchmark for the minimum required equipment. If it is not needed, it will not be required.

The third issue is reliability; the generation system must be designed and interconnected such that the reliability and the service quality for all customers of the electrical power systems are not compromised. This applies to all electrical systems not just the Area EPS.

Many generation interconnection standards exist or are in draft form. The IEEE, FERC and many states have been working on generation interconnection standards. There are other standards such as the National Electrical Code (NEC) that, establish requirements for electrical installations. The NEC requirements are in addition to this standard. This standard is designed to document the requirements where the NEC has left the establishment of the standard to “the authority having jurisdiction” or to cover issues which are not covered in other national standards.

This standard covers installations, with an aggregated capacity up to 10MWs. Many of the requirements in this document do not apply to small, 40kW or less generation installations. As an aid to the small, distributed generation customer, these small unit interconnection requirements have been extracted from this full standard and are available as a separate, simplified document titled: “Standards for Interconnecting Inverter based Generation Sources, Rated Less then 40kW with Minnesota Electric Utilities”

1. Introduction

This standard has been developed to document the technical requirements for the interconnection between a Generation System and an area electrical power system "Utility system or Area EPS". This standard covers 3 phase Generation Systems with an aggregate capacity of 10 MW's or less and single phase Generation Systems with a aggregate capacity of 40kW or less at the Point of Common Coupling. This standard covers Generation Systems that are interconnected with the Area EPS's distribution facilities. This standard does not cover Generation Systems that are directly interconnected with the Area EPS's Transmission System, Contact the Area EPS for their Transmission System interconnection standards.

While, this standard provides the technical requirements for interconnecting a Generation System with a typical radial distribution system, it is important to note that there are some unique Area EPS, which have special interconnection needs. One example of a unique Area EPS would be one operated as a "networked" system. This standard does not cover the additional special requirements of those systems. The Generating Entity must contact the Owner/operator of the Area EPS with which the interconnection is intended, to make sure that the Generation System is not proposed to be interconnected with a unique Area EPS. If the planned interconnection is with a unique Area EPS, the Generating Entity must obtain the additional requirements for interconnecting with the Area EPS.

The Area EPS operator has the right to limit the maximum size of any Generation System or number of Generation Systems that, may want to interconnect, if the Generation System would reduce the reliability to the other customers connected to the Area EPS.

A) This standard only covers the technical requirements and does not cover the interconnection process from the planning of a project through approval and construction. Please read the companion document "Minnesota State Generation Interconnection Application Guide" for the description of the procedure to follow and a generic version of the forms to submit. It is important to also get copies of the Area EPS's tariff's concerning generation interconnection which will include rates, costs and standard interconnection agreements. The earlier the Generating Entity gets the Area EPS operator involved in the planning and design of the Generation System interconnection the smoother the process will go.

B) Definitions

The definitions defined in the "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems" (1547 Draft Ver. 10) apply to this document as well. The following definitions are in addition to the ones defined in IEEE 1547 V10, or are repeated from the IEEE 1547 V10 standard.

i) "Area EPS" is defined as an electric power system (EPS) that serves Local EPS's. Note. Typically, an Area EPS has primary access to public rights-of-way, priority crossing of property boundaries, etc.

ii) "Generation" is defined as any device producing electrical energy, i.e., rotating generators driven by wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc.; or any other electric producing device, including energy storage technologies.

iii) "Generation System" is defined as the interconnected Distributed Generation(s), controls, relays, switches, breakers, transformers, inverters and associated wiring and cables, up to the Point of Common Coupling.

iv) "Generating Entity" is defined as the party or parties who are responsible for meeting the requirements of this standard. This could be the Generation System applicant, installer, designer, owner or operator.

v) "Local EPS" an electric power system (EPS) contained entirely within a single premises or group of premises.

vi) "Point of Common Coupling" is the point where the Local EPS is connected to an Area EPS.

vii) "Transmission System", are those facilities as defined by using the guidelines established by the Minnesota State Public Utilities Commission; "In the Matter of Developing Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions" Docket No. E-015/M-99-1002.

viii) "Type-Certified" Generation paralleling equipment that is listed by a OSHA listed national testing laboratory as having met the applicable type testing requirement of UL 1741. At the time is document was prepared this was the only national standard available for certification of generation transfer switch equipment. This definition does not preclude other forms of type-certification if agreeable to the Area EPS operator.

C) Interconnection Requirements Goals

This standard defines the technical requirements for the implementation of the electrical interconnection between the Generation System and the Area EPS. It does not define the overall requirements for the Generation System. The requirements in this standard are intended to achieve the following:

i) Ensure the safety of utility personnel and contractors working on the electrical power system.

ii) Ensure the safety of utility customers and the general public.

iii) Protect and minimize the possible damage to the electrical power system and other customer's property.

iv) Ensure proper operation to minimize adverse operating conditions on the electrical power system.

D) Protection

The Generation System and Point of Common Coupling shall be designed with proper protective devices to promptly and automatically disconnect the Generation from the Area EPS in the event of a fault or other system abnormality. The type of protection required will be determined by:

i) Size and type of the generating equipment.

ii) The method of connecting and disconnecting the Generation System from the electrical power system.

iii) The location of generating equipment on the Area EPS.

E) Area EPS Modifications

Depending upon the match between the Generation System, the Area EPS and how the Generation System is operated, certain modifications and/or additions may be required to the existing Area EPS with the addition of the Generation System. To the extent possible, this standard describes the modifications which could be necessary to the Area EPS for different types of Generation Systems. For some unique interconnections, additional and/or different protective devices, system modifications and/or additions will be required by the Area EPS operator; In these cases the Area EPS operator will provide the final determination of the required modifications and/or additions. If any special requirements are necessary they will be identified by the Area EPS operator during the application review process.

F) Generation System Protection

The Generating Entity is solely responsible for providing protection for the

Generation System. Protection systems required in this standard, are structured to protect the Area EPS's electrical power system and the public. The Generation System Protection is not provided for in this standard. Additional protection equipment may be required to ensure proper operation for the Generation System. This is especially true while operating disconnected, from the Area EPS. The Area EPS does not assume responsibility for protection of the Generation System equipment or of any portion Local EPS.

G) Electrical Code Compliance

Generating Entity shall be responsible for complying with all applicable local, independent, state and federal codes such as building codes, National Electric Code (NEC), National Electrical Safety Code (NESC) and noise and emissions standards. As required by Minnesota State law, the Area EPS will require proof of complying with the National Electrical Code before the interconnection is made, through installation approval by an electrical inspector recognized by the Minnesota State Board of Electricity.

The Generating Entity's Generation System and installation shall comply with latest revisions of the ANSI/IEEE standards applicable to the installation, especially IEEE 1547 Draft V10 "Standard for Interconnecting Distributed Resources with Electric Power Systems". See the reference section in this document for the a partial list of the standards which apply to the generation installations covered by this standard.

2. References

The following standards shall be used in conjunction with this standard. When the stated version of the following standards is superseded by an approved revision then that revision shall apply.

IEEE Std 100-2000, "IEEE Standard Dictionary of Electrical and Electronic Terms"

IEEE Std 519-1992, "IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems"

IEEE Std 929-2000,"IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems".

IEEE Std 1547 V10, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems"

IEEE Std C37.90.1-1989 (1995), "IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems".

IEEE Std C37.90.2 (1995), "IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers".

IEEE Std C62.41.2-2002, "IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits"

IEEE Std C62.42-1992 (2002), "IEEE Recommended Practice on Surge Testing for Equipment Connected to Low Voltage (1000V and less) AC Power Circuits"

ANSI C84.1-1995,"Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)"

ANSI/IEEE 446-1995, "Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications".

ANSI/IEEE Standard 80, "IEEE Guide for Safety in AC Substation Grounding",

UL Std. 1741 "Inverters, Converters, and Controllers for use in Independent Power Systems"

NEC – "National Electrical Code", National Fire Protection Association (NFPA), NFPA-70-2002.

NESC – "National Electrical Safety Code". ANSI C2-2000, Published by the Institute of Electrical and Electronics Engineers, Inc.

3. Types of Interconnections

A) The manner in which the Generation System is connected to and disconnected from the Area EPS can vary. Most transfer systems normally operate using one of the following five methods of transferring the load from the Area EPS to the Generation System.

B) If a transfer system is installed which has a user accessible selection of several transfer modes, the transfer mode that has the greatest protection requirements will establish the protection requirements for that transfer system.

i) <u>Open Transition (Break-Before-Make) Transfer Switch</u> – With this transfer switch, the load to be supplied from the Distributed Generation is first disconnected from the Area EPS and then connected to the Generation. This transfer can be relatively quick, but voltage and frequency excursions are to be expected during transfer. Computer equipment and other sensitive equipment will shut down and reset. The transfer switch typically consists of a standard UL approved transfer switch with mechanical interlocks between the two source contactors that drop the Area EPS source before the Distributed Generation is connected to supply the load.

(1) To qualify as an Open Transition switch and the limited protective requirements, mechanical interlocks are required between the two source contacts. This is required to ensure that one of the contacts is always open and the Generation System is never operated in parallel with the Area EPS. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch.

(2) As a practical point of application, this type of transfer switch is typically used for loads less then 500kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending up the Area EPS's stiffness this level may be larger or smaller then the 500kW level.

(3) Figure 1 at the end of this document provides a typical one-line of this type of installation.

ii) <u>Quick Open Transition (Break-Before-Make) Transfer Switch</u> – The load to be supplied from the Distributed Generation is first disconnected from the Area EPS and then connected to the Distributed Generation, similar to the open transition. However, this transition is typically much faster (under 500 ms) than the conventional open transition transfer operation. Voltage and frequency excursions will still occur, but some computer equipment and other sensitive equipment will typically not be affected with a properly designed system. The transfer switch consists of a standard UL approved transfer switch, with mechanical interlocks between the two source contacts that drop the Area EPS source before the Distributed Generation is connected to supply the load.

(1) Mechanical interlocks are required between the two source contacts to ensure that one of the contacts is always open. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch

(2) As a practical point of application this type of transfer switch is typically used for loads less then 500kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending up the Area EPS's stiffness this level may be larger or smaller than the 500kW level.

(3) Figure 2 at the end of this document provides a typical one-line of this type of installation and shows the required protective elements.

iii) Closed Transition (Make-Before-Break) Transfer Switch – The Distributed Generation is synchronized with the Area EPS prior to the transfer occurring. The transfer switch then parallels with the Area EPS for a short time (0.5 seconds or less) and then the Generation System and load is disconnect from the Area EPS. This transfer is less disruptive than the Quick Open Transition because it allows the Distributed Generation a brief time to pick up the load before the support of the Area EPS is lost. With this type of transfer, the load is always being supplied by the Area EPS or the Distributed Generation.

(1) As a practical point of application this type of transfer switch is typically used for loads less then 500kW. This is due to possible voltage flicker problems created on the Area EPS, when the load is removed from or returned to the Area EPS source. Depending up the Area EPS's stiffness this level may be larger or smaller then the 500kW level.

(2) Figure 2 at the end of this document provides a typical one-line of this type of installation and shows the required protective elements. The closed transition switch must include a separate parallel time limit relay, which is not part of the generation control PLC and trips the generation from the system for a failure of the transfer switch and/or the transfer switch controls.

iv) Soft Loading Transfer Switch

(1) With Limited Parallel Operation – The Distributed Generation is paralleled with the Area EPS for a limited amount of time (generally less then 1-2 minutes) to gradually transfer the load from the Area EPS to the Generation System. This minimizes the voltage and frequency problems, by softly loading and unloading the Generation System.

(a) The maximum parallel operation shall be controlled, via a parallel timing limit relay (62PL). This parallel time limit relay shall be a separate relay and not part of the generation control PLC.

(b) Protective Relaying is required as described in section 6.

(c) Figure 3 at the end of this document provide typical one-line diagrams of this type of installation and show the required protective elements.

(2) With Extended Parallel Operation – The Generation System is paralleled with the Area EPS in continuous operation. Special design, coordination and agreements are required before any extended parallel operation will be permitted. The Area EPS interconnection study will identify the issues involved.

(a) Any anticipated use in the extended parallel mode requires special agreements and special protection coordination.

(b) Protective Relaying is required as described in section 6.

(c) Figure 4 at the end of this document provides a typical one-line for the this type of interconnection. It must be emphasized that this is a typical installations only and final installations may vary from the examples shown due to transformer connections, breaker configuration, etc.

v) Inverter Connection

This is a continuous parallel connection with the system. Small Generation Systems may utilize inverters to interface to the Area EPS. Solar, wind and fuel cells are some examples of Generation which typically use inverters to connect to the Area EPS. The design of such inverters shall either contain all necessary protection to prevent unintentional islanding, or the Generating Entity shall install conventional protection to affect the same protection. All required protective elements for a soft-loading transfer switch apply to an inverter connection. Figure 5 at the end of this document, shows a typical inverter interconnection.

(1) Inverter Certification – Prior to installation, the inverter shall be Type-Certified for interconnection to the electrical power system. The certification will confirm its anti-islanding protection and power quality related levels at the Point of Common Coupling. Also, utility compatibility, electric shock hazard and fire safety are approved through UL listing of the model. Once this Type Certification is completed for that specific model, additional design review of the inverter should not be necessary by the Area EPS operator.

(2) For three-phase operation, the inverter control must also be able to detect and separate for the loss of one phase. Larger inverters will still require

custom protection settings, which must be calculated and designed to be compatible with the specific Area EPS being interconnected with.

(3) A visible disconnect is required for safely isolating the Distributed Generation when connecting with an inverter. The inverter shall not be used as a safety isolation device.

(4) When banks of inverter systems are installed at one location, a design review by the Area EPS must be preformed to determine any additional protection systems, metering or other needs. The issues will be identified by the Area EPS during the interconnection study process

4. Interconnection Issues and Technical Requirements

A) General Requirements - The following requirements apply to all interconnected generating equipment. The Area EPS shall be the source side and the customer's system shall be the load side in the following interconnection requirements.

i) Visible Disconnect - A disconnecting device shall be installed to electrically isolate the Area EPS from the Generation System. The only exception for the installation of a visible disconnect is if the generation is interconnected via a mechanically interlocked open transfer switch and installed per the NEC (702.6) "so as to prevent the inadvertent interconnection of normal and alternate sources of supply in any operation of the transfer equipment."

The visible disconnect shall provide a visible air gap between Generating Entity's Generation and the Area EPS in order to establish the safety isolation required for work on the Area EPS. This disconnecting device shall be readily accessible 24 hours per day by the Area EPS field personnel and shall be capable of padlocking by the Area EPS field personnel. The disconnecting device shall be lockable in the open position.

The visible disconnect shall be a UL approved or National Electrical Manufacture's Association approved, manual safety disconnect switch of adequate ampere capacity. The visible disconnect shall not open the neutral when the switch is open.

The visible disconnect shall be labeled "Generation Disconnect" to inform the Area EPS field personnel.

ii) Energization of Equipment by Generation System – The Generation System shall not energize a de-energized Area EPS. The Generating Entity shall install the necessary padlocking (lockable) devices on equipment to prevent the energization of a de-energized electrical power system. Lock out relays shall automatically block the closing of breakers or transfer switches on to a de-energized Area EPS.

iii) Power Factor - The power factor of the Generation System and connected load shall be as follows;

(1) Inverter Based interconnections – shall operate at a power factor of no less then 90%.at the inverter terminals.

(2) Limited Parallel Generation Systems, such as closed transfer or soft-loading transfer systems shall operate at a power factor of no less then 90%, during the period when the Generation System is parallel with the Area EPS, as measured at the Point of Common Coupling.

(3) Extended Parallel Generation Systems shall be designed to be capable of

operating between 90% lagging and 95% leading. These Generation Systems shall normally operate near unity power factor (+/-98%) or as mutually agreed between the Area EPS operator and the Generating Entity.

iv) Grounding Issues

(1) Grounding of sufficient size to handle the maximum available ground fault current shall be designed and installed to limit step and touch potentials to safe levels as set forth in "IEEE Guide for Safety in AC Substation Grounding", ANSI/IEEE Standard 80.

(2) All electrical equipment shall be grounded in accordance with local, state and federal electrical and safety codes and applicable standards

v) Sales to Area EPS or other parties – Transportation of energy on the Transmission system is regulated by the area reliability council and FERC. Those contractual requirements are not included in this standard. The Area EPS will provide these additional contractual requirements during the interconnection approval process.

B) For Inverter based, closed transfer and soft loading interconnections - The following additional requirements apply:

i) Fault and Line Clearing - The Generation System shall be removed from the Area EPS for any faults, or outages occurring on the electrical circuit serving the Generation System

ii) Operating Limits in order to minimize objectionable and adverse operating conditions on the electric service provided to other customers connected to the Area EPS, the Generation System shall meet the Voltage, Frequency, Harmonic and Flicker operating criteria as defined in the IEEE 1547 V10 standard during periods when the Generation System is operated in parallel with the Area EPS.

If the Generation System creates voltage changes greater than 4% on the Area EPS, it is the responsibility of the Generating Entity to correct these voltage sag/swell problems caused by the operation of the Generation System. If the operation of the interconnected Generation System causes flicker, which causes problems for others customers interconnected to the Area EPS, the Generating Entity is responsible for correcting the problem.

iii) Flicker - The operation of Generation System is not allowed to produce excessive flicker to adjacent customers. See the IEEE 1547 V10 standard for a more complete discussion on this requirement.

The stiffer the Area EPS, the larger a block load change that it will be able to handle. For any of the transfer systems the Area EPS voltage shall not drop or rise greater than 4% when the load is added or removed from the Area EPS. It is important to note, that if another interconnected customer complains about the voltage change caused by the Generation System, even if the voltage change is below the 4% level, it is the Generating Entity's responsibility to correct or pay for correcting the problem. Utility experience has shown that customers have seldom objected to instantaneous voltage changes of less then 2% on the Area EPS, so most Area EPS operators use a 2% design criteria

iv) Interference - The Generating Entity shall disconnect the Distributed Generation from the Area EPS if the Distributed Generation causes radio, television or electrical service interference to other customers, via the EPS or interference with the operation of Area EPS. The Generating Entity shall either effect repairs to the Generation System or reimburse the Area EPS Operator for the cost of any required Area EPS modifications due to the interference.

v) Synchronization of Customer Generation-

(1) An automatic synchronizer with synch-check relaying is required for unattended automatic quick open transition, closed transition or soft loading transfer systems.

(2) To prevent unnecessary voltage fluctuations on the Area EPS, it is required that the synchronizing equipment be capable of closing the Distributed Generation into the Area EPS within the limits defined in IEEE 1547 V10. Actual settings shall be determined by the Registered Professional Engineer establishing the protective settings for the installation.

(3) Unintended Islanding – Under certain conditions with extended parallel operation, it would be possible for a part of the Area EPS to be disconnected from the rest of the Area EPS and have the Generation System continue to operate and provide power to a portion of the isolated circuit. This condition is called "islanding". It is not possible to successfully reconnect the energized isolated circuit to the rest of the Area EPS since there are no synchronizing controls associated with all of the possible locations of disconnection. Therefore, it is a requirement that the Generation System be automatically disconnected from the Area EPS immediately by protective relays for any condition that would cause the Area EPS to be de-energized. The Generation System must either isolate with the customer's load or trip. The Generation System must also be blocked from closing back into the Area EPS until the Area EPS is reenergized and the Area EPS voltage is within Range B of ANSI C84.1 Table 1 for a minimum of 1 minute. Depending upon the size of the Generation System it may be necessary to install direct transfer trip equipment from the Area EPS source(s) to remotely trip the generation interconnection to prevent islanding for certain conditions

vi) <u>Disconnection</u> – the Area EPS operator may refuse to connect or may disconnect a Generation System from the Area EPS under the following conditions:

(1) Lack of approved Standard Application Form and Standard Interconnection Agreement.

(2) Termination of interconnection by mutual agreement.

(3) Non-Compliance with the technical or contractual requirements.

(4) System Emergency or for imminent danger to the public or Area EPS personnel (Safety).

(5) Routine maintenance, repairs and modifications to the Area EPS. The Area EPS operator shall coordinate planned outages with the Generation Entity to the extent possible.

5. Generation Metering, Monitoring And Control

Metering, Monitoring and Control – Depending upon the method of interconnection and the size of the Generation System, there are different metering, monitoring and control requirements Table 5A is a table summarizing the metering, monitoring and control requirements..

Due to the variation in Generation Systems and Area EPS operational needs, the requirements for metering, monitoring and control listed in this document are the expected maximum requirements that the Area EPS will apply to the Generation System. It is important to note that for some Generation System installations the Area EPS may wave some of the requirements of this section if they are not needed. An example of this is with rural or low capacity feeders which require more monitoring then larger capacity, typically urban feeders.

Another factor which will effect the metering, monitoring and control requirements will be the tariff under which the Generating Entity is supplied by the Area EPS. Table 5A has been written to cover most application, but some Area EPS tariffs may have greater or less metering, monitoring and control requirements then, as shown in Table 5A. .

TABLE 5A
Metering, Monitoring and Control Requirements

Generation System Capacity at Point of Common Coupling	Metering	Generation Remote Monitoring	Generation Remote Control
< 40 kW with all sales to Area EPS	Bi-Directional metering at the point of common coupling	None Required	None Required
< 40 kW with Sales to a party other then the Area EPS	Recording metering on the Generation System and a separate recording meter on the load	Generating Entity supplied direct dial phone line.	None Required
40 – 250kW with limited parallel	Detented Area EPS Metering at the Point of Common Coupling	None Required	None Required
40 – 250kW with extended parallel	Recording metering on the Generation System and a separate recording meter on the load	Generation Entity supplied direct dial phone line. Area EPS to supply it's own monitoring equipment	None Required
250 – 1000 kW with limited parallel	Detented Area EPS Metering at the Point of Common Coupling	Generating Entity supplied direct dial phone line and monitoring points available. See B (i)	None Required
250 – 1000 kW With extended parallel operation	Recording metering on the Generation System and a separate recording meter on the load.	Required Area EPS remote monitoring system See B (i)	None Required
>1000 kW With limited parallel Operation	Detented Area EPS Metering at the Point of Common Coupling	Required Area EPS SCADA monitoring system. See B (i)	None required
>1000 kW With extended parallel operation	Recording metering on the Generation System and a separate recording meter on the load.	Required Area EPS SCADA monitoring system See B (i)	Direct Control via SCADA by Area EPS of interface breaker.

"Detented" = A meter which is detented will record power flow in only one direction.

A) Metering

i) As shown in Table 5A the requirements for metering will depend up on the type of generation and the type of interconnection. For most installations, the requirement is a single point of metering at the Point of Common Coupling. The Area EPS Operator will install a special meter that is capable of measuring and recording energy flow in both directions, for three phase installations or two detented meters wired in series, for single phase installations.. A dedicated - direct dial phone line may be required to be supplied to the meter for the Area EPS's use to read the metering. Some monitoring may be done through the meter and the dedicated – direct dial phone line, so in many installations the remote monitoring and the meter reading can be done using the same dial-up phone line.

ii) Depending upon which tariff the Generation System and/or customer's load is being supplied under, additional metering requirements may result. Contact the Area EPS for tariff requirements. In some cases, the direct dial-phone line requirement may be waived by the Area EPS for smaller Generation Systems.

iii) All Area EPS's revenue meters shall be supplied, owned and maintained by the Area EPS. All voltage transformers (VT) and current transformers (CT), used for revenue metering shall be approved and/or supplied by the Area EPS. Area EPS's standard practices for instrument transformer location and wiring shall be followed for the revenue metering.

iv) For Generation Systems that sell power and are greater then 40kW in size, separate metering of the generation and of the load is required. A single meter recording the power flow at the Point of Common Coupling for both the Generation and the load, is not allowed by the rules under which the area transmission system is operated. The Area EPS is required to report to the regional reliability council (MAPP) the total peak load requirements and is also required to own or have contracted for, accredited generation capacity of 115% of the experienced peak load level for each month of the year. Failure to meet this requirement results in a large monetary penalty for the Area EPS operator.

v) For Generation Systems which are less then 40kW in rated capacity and are qualified facilities under PURPA (Public Utilities Regulatory Power Act – Federal Gov. 1978), net metering is allowed and provides the generation system the ability to back feed the Area EPS at some times and bank that energy for use at other times. Some of the qualified facilities under PURPA are solar, wind, hydro, and biomass. For these net-metered installations, the Area EPS may use a single meter to record the bi-directional flow or the Area EPS Operator may elect to use two detented meters, each one to record the flow of energy in one direction.

B) Monitoring (SCADA) is required as shown in table 5A. The need for monitoring is based on the need of the system control center to have the information necessary for the reliable operation of the Area EPS's. This remote monitoring is especially important during periods of abnormal and emergency operation.

The difference in Table 5A between remote monitoring and SCADA is that SCADA typically is a system that is in continuous communication with a central computer and provides updated values and status, to the Area EPS operator, within several seconds of the changes in the field. Remote monitoring on the other hand will tend to provide updated values and status within minutes of the change in state of the field. Remote monitoring is typically less expensive to install and operate.

i) Where Remote Monitoring or SCADA is required, as shown in Table 5A, the following monitored and control points are required:

(1) Real and reactive power flow for each Generation System (kW and kVAR). Only required if separate metering of the Generation and the load is required, otherwise #4 monitored at the point of Common Coupling will meet the requirements.

(2) Phase voltage representative of the Area EPS's service to the facility.

(3) Status (open/close) of Distributed Generation and interconnection breaker(s) or if transfer switch is used, status of transfer switch(s).

(4) Customer load from Area EPS service (kW and kVAR).

(5) Control of interconnection breaker - if required by the Area EPS operator.

When telemetry is required, the Generating Entity must provide the communications medium to the Area EPS's Control Center. This could be radio, dedicated phone circuit or other form of communication. If a telephone circuit is used, the Generating Entity must also provide the telephone circuit protection. The Generating Entity shall coordinate the RTU (remote terminal unit) addition with the Area EPS. The Area EPS may require a specific RTU and/or protocol to match their SCADA or remote monitoring system.

6. Protective Devices and Systems

A) Protective devices required to permit safe and proper operation of the Area EPS while interconnected with customer's Generation System are shown in the figures at the end of this document. In general, an increased degree of protection is required for increased Distributed Generation size. This is due to the greater magnitude of short circuit currents and the potential impact to system stability from these installations. Medium and large installations require more sensitive and faster protection to minimize damage and ensure safety.

If a transfer system is installed which has a user accessible selection of several transfer modes, the transfer mode which has the greatest protection requirements will establish the protection requirements for that transfer system.

The Generating Entity shall provide protective devices and systems to detect the Voltage, Frequency, Harmonic and Flicker levels as defined in the IEEE 1547 V10 standard during periods when the Generation System is operated in parallel with the Area EPS. The Generating Entity shall be responsible for the purchase, installation, and maintenance of these devices. Discussion on the requirements for these protective devices and systems follows:

i) Relay settings

(1) If the Generation System is utilizing a Type-Certified system, such as a UL listed inverter a Professional Electrical Engineer is not required to review and approve the design of the interconnecting system. If the Generation System interconnecting device is not Type-Certified or if the Type-Certified Generation System interconnecting device has additional design modifications made, the Generation System control, the protective system, and the interconnecting device(s) shall be reviewed and approved by a Professional Electrical Engineer, registered in the State of Minnesota.

(2) A copy of the proposed protective relay settings shall be supplied to the Area EPS operator for review and approval, to ensure proper coordination between the generation system and the Area EPS.

ii) Relays

(1) All equipment providing relaying functions shall meet or exceed ANSI/IEEE Standards for protective relays, i.e., C37.90, C37.90.1 and C37.90.2.

(2) Required relays that are not "draw-out" cased relays shall have test plugs or test switches installed to permit field testing and maintenance of the relay without unwiring or disassembling the equipment. Inverter based protection is excluded from this requirement for Generation Systems

<40kW at the Point of Common Coupling.

(3) Three phase interconnections shall utilize three phase power relays, which monitor all three phases of voltage and current, unless so noted in the appendix one-lines.

(4) All relays shall be equipped with setting limit ranges at least as wide as specified in IEEE 1547 V10, and meet other requirements as specified in the Area EPS interconnect study. Setting limit ranges are not to be confused with the actual relay settings required for the proper operation of the installation. At a minimum, all protective systems shall meet the requirements established in IEEE 1547 V10.

(a) Over-current relays (IEEE Device 50/51 or 50/51V) shall operate to trip the protecting breaker at a level to ensure protection of the equipment and at a speed to allow proper coordination with other protective devices. For example, the over-current relay monitoring the interconnection breaker shall operate fast enough for a fault on the customer's equipment, so that no protective devices will operate on the Area EPS. 51V is a voltage restrainted or controlled over-current relay and may be required to provide proper coordination with the Area EPS.

(b) Over-voltage relays (IEEE Device 59) shall operate to trip the Distributed Generation per the requirements of IEEE 1547 V10.

(c) Under-voltage relays (IEEE Device 27) shall operate to trip the Distributed Generation per the requirements of IEEE 1547 V10

(d) Over-frequency relays (IEEE Device 81O) shall operate to trip the Distributed Generation off-line per the requirements of IEEE 1547 V10.

(e) Under-frequency relay (IEEE Device 81U) shall operate to trip the Distributed Generation off-line per the requirements of IEEE 1547 V10. For Generation Systems with an aggregate capacity greater then 30kW, the Distribution Generation shall trip off-line when the frequency drops below 57.0-59.8 Hz. Typically this is set at 59.5 Hz, with a trip time of 0.16 seconds, but coordination with the Area EPS is required for this setting.

The Area EPS will provide the reference frequency of 60 Hz. The Distributed Generation control system must be used to match this reference. The protective relaying in the interconnection system will be expected to maintain the frequency of the output of the Generation.

(f) Reverse power relays (IEEE Device 32) (power flowing from the Generation System to the Area EPS) shall operate to trip the Distributed Generation off-line for a power flow to the system with a maximum time delay of 2.0 seconds.

(g) Lockout Relay (IEEE Device 86) is a mechanically locking device which is wired into the close circuit of a breaker or switch and when tripped will prevent any close signal from closing that device. This relay requires that a person manually resets the lockout relay before that device can be reclosed. These relays are used to ensure that a denergized system is not reenergized by automatic control action, and prevents a failed control from auto-reclosing an open breaker or switch.

(h) Transfer Trip – All Generation Systems are required to disconnect from the Area EPS when the Area EPS is disconnected from its source, to avoid unintentional islanding. With larger Generation Systems, which remain in parallel with the Area EPS, a transfer trip system may be required to sense the loss of the Area EPS source. When the Area EPS source is lost, a signal is sent to the Generation System to separate the Generation from the Area EPS. The size of the Generation System vs the capacity and minimum loading on the feeder will dictate the need for transfer trip installation. The Area EPS interconnection study will identify the specific requirements.

If multiple Area EPS sources are available or multiple points of sectionalizing on the Area EPS, then more then one transfer trip system may be required. Area EPS interconnection study will identify the specific requirements. For some installations the alternate Area EPS source(s) may not be utilized except in rare occasions. If this is the situation, the Generating Entity may elect to have the Generation System locked out when the alternate source(s) are utilized, if agreeable to the Area EPS operator.

(i) Parallel limit timing relay (IEEE Device 62PL) set at a maximum of 120 seconds for soft transfer installations and set no longer then 100ms for quick transfer installations, shall trip the Distributed Generation circuit breaker on limited parallel interconnection systems. Power for the 62 PL relay must be independent of the transfer switch control power. The 62PL timing must be an independent device from the transfer control and shall not be part of the generation PLC or other control system.

TABLE 6A
SUMMARY OF RELAYING REQUIREMENTS

Type of Interconnection	Over-current (50/51)	Voltage (27/59)	Frequency (81 0/U)	Reverse Power (32)	Lockout (86)	Parallel Limit Timer	Sync-Check (25)	Transfer Trip
Open Transition Mechanically Interlocked (Fig. 1)	—	—	—	—	—	—	—	—
Quick Open Transition Mechanically Interlocked (Fig. 2)	—	—	—	—	Yes	Yes	Yes	—
Closed Transition (Fig. 2)	—	—	—	—	Yes	Yes	Yes	—
Soft Loading Limited Parallel Operation (Fig. 3)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	—
Soft Loading Extended Parallel < 250 kW (Fig. 4)	Yes	Yes	Yes	—	Yes	—	Yes	—
Soft Loading Extended Parallel >250kW (Fig.4)	Yes	Yes	Yes	—	Yes	—	Yes	Yes
Inverter Connection (Fig. 5)								
< 40 kW	Yes	Yes	Yes	—	Yes	—	—	—
40 kW – 250kW	Yes	Yes	Yes	—	Yes	—	—	—
> 250 kW	Yes	Yes	Yes	—	Yes	—	—	Yes

7. Agreements

A) Interconnection Agreement – This agreement is required for all Generation Systems that parallel with the Area EPS. Each Area EPS's tarriffs contain standard interconnection agreements. There are different interconnection agreements depending upon the size and type of Generation System. This agreement contains the terms and conditions upon which the Generation System is to be connected, constructed and maintained, when operated in parallel with the Area EPS. Some of the issues covered in the interconnection agreement are as follows;

i) Construction Process

ii) Testing Requirements

iii) Maintenance Requirements

iv) Firm Operating Requirements such as Power Factor

v) Access requirements for the Area EPS personnel

vi) Disconnection of the Generation System (Emergency and Non-emergency)

vii) Term of Agreement

viii) Insurance Requirements

ix) Dispute Resolution Procedures

B) Operating Agreement – For Generation Systems that normally operate in parallel with the Area EPS, an agreement separate from the interconnection agreement, called the "operating agreement", is usually created. This agreement is created for the benefit of both the Generation Entity and the Area EPS operator and will be agreed to between the Parties. This agreement will be dynamic and is intended to be updated and reviewed annually. For some smaller systems, the operating agreement can simply be a letter agreement for larger and more intergraded Generation Systems the operating agreement will tend to be more involved and more formal. The operating agreement covers items that are necessary for the reliable operation of the Local and Area EPS. The items typically included in the operating agreement are as follows;

i) Emergency and normal contact information for both the Area EPS operations center and for the Generating Entity

ii) Procedures for periodic Generation System test runs.

iii) Procedures for maintenance on the Area EPS that effect the Generation System.

iv) Emergency Generation Operation Procedures

8. Testing Requirements

A) Pre-Certification of equipment

i) Generation paralleling equipment that is listed by a nationally recognized testing laboratory as having met the applicable Type-Testing requirements of UL 1741 (most current revision) and IEEE 929, shall be acceptable for interconnection without additional protection systems. Type-Certified paralleling equipment may be utilized for the interconnection to an Area EPS without further design review of the equipment by the Area EPS operator. The use of Type-Certified equipment does not automatically qualify the Generating Entity to be interconnected to the Area EPS. An application will still need to be submitted and an interconnection review may still need to be performed, to determine the compatibility of the Generation System with the Area EPS capabilities at the Point of Common Coupling.

B) Pre-Commissioning Tests

i) Non-Certified Equipment

(1) Protective Relaying and Equipment Related to Islanding

(a) Distributed generation that is not Type-Certified (type tested), shall be equipped with protective hardware and/or software designed to prevent the Generation from being connected to a de-energized Area EPS.

(b) The Generation may not close into a de-energized Area EPS and protection provided to prevent this from occurring. It is the Generating Entity's responsibility to provide a final design and to install the protective measures required by the Area EPS. The Area EPS will review and approve the design, the types of relays specified, and the installation. Mutually agreed upon exceptions may at times be necessary and desirable. It is strongly recommended that the Generating Entity obtain Area EPS written approval prior to ordering protective equipment for parallel operation. The Generating Entity will own these protective measures installed at their facility.

(c) The Generating Entity shall obtain prior approval from the Area EPS for any revisions to the specified relay calibrations.

C) Commissioning Testing

The following tests shall be completed by the Generating Entity. All of the required tests in each section shall be completed prior to moving on to the next section of tests. The Area EPS operator has the right to witness all field testing and to review all records prior to allowing the system to be made ready for normal operation The

Area EPS shall be notified, with sufficient lead time to allow the opportunity for Area EPS personnel to witness any or all of the testing.

i) Pre-testing The following tests are required to be completed on the Generation System prior to energization by the Generator or the Area EPS. Some of these tests may be completed in the factory if no additional wiring or connections were made to that component. These tests are marked with a "*"

(1) Grounding shall be verified to ensure that it complies with this standard, the NESC and the NEC.

(2) * CT's (Current Transformers) and VT's (Voltage Transformers) used for monitoring and protection, shall be tested to ensure correct polarity, ratio and wiring

(3) CT's shall be visually inspected to ensure that all grounding and shorting connections have been removed where required.

(4) Breaker / Switch tests – Verify that the breaker or switch cannot be operated with interlocks in place or that the breaker or switch cannot be automatically operated when in manual mode. Various Generation Systems have different interlocks, local or manual modes etc. The intent of this section is to ensure that the breaker or switches controls are operating properly.

(5) * Relay Tests – All Protective relays shall be calibrated and tested to ensure the correct operation of the protective element. Documentation of all relay calibration tests and settings shall be furnished to the Area EPS operator.

(6) Trip Checks - Protective relaying shall functionally tested to ensure the correct operation of the complete system. Functional testing requires that the complete system is operated by the injection of current and/or voltage to trigger the relay element and proving that the relay element trips the required breaker, lockout relay or provides the correct signal to the next control element. Trip circuits shall be proven through the entire scheme (including breaker trip)

For factory assembled systems, such as inverters the setting of the protective elements may occur at the factory. This section requires that the complete system including the wiring and the device being tripped or activated is proven to be in working condition through the injection of current and/or voltage.

(7) Remote Control, SCADA and Remote Monitoring tests – All remote control functions and remote monitoring points shall be verified operational. In some cases, it may not be possible to verify all of the analog values prior to energization. Where appropriate, those points may be verified during the

energization process

(8) Phase Tests – the Generating Entity shall work with the Area EPS operator to complete the phase test to ensure proper phase rotation of the Generation and wiring.

(9) Synchronizing test – The following tests shall be done across a open switch or racked out breaker. The switch or breaker shall be in a position that it is incapable of closing between the Generation System and the Area EPS for this test. This test shall demonstrate that at the moment of the paralleling-device closure, the frequency, voltage and phase angle are within the required ranges, stated in IEEE 1547 V10. This test shall also demonstrate that is any of the parameters are outside of the ranges stated; the paralleling-device shall not close. For inverter-based interconnected systems this test may not be required unless the inverter creates fundamental voltages before the paralleling device is closed.

ii) On-Line Commissioning Test – the following tests will proceed once the Generation System has completed Pre-testing and the results have been reviewed and approved by the Area EPS operator. For smaller Generation Systems the Area EPS may have a set of standard interconnection tests that will be required. On larger and more complex Generation Systems the Generating Entity and the Area EPS operator will get together to develop the required testing procedure. All on-line commissioning test shall be based on written test procedures agreed to between the Area EPS operator and the Generating Entity.

Generation System functionally shall be verified for specific interconnections as follows:

(1) Anti-Islanding Test – For Generation Systems that parallel with the utility for longer then 100msec.

(a) The Generation System shall be started and connected in parallel with the Area EPS source

(b) The Area EPS source shall be removed by opening a switch, breaker etc.

(c) The Generation System shall either separate with the local load or stop generating

(d) The device that was opened to remove the Area EPS source shall be closed and the Generation System shall not reparallel with the Area EPS for at least 5 minutes.

iii) Final System Sign-off.

(1) To ensure the safety of the public, all interconnected customer owned generation systems which do not utilize a Type-Certified system shall be certified as ready to operate by a Professional Electrical Engineer registered in the State of Minnesota, prior to the installation being considered ready for commercial use.

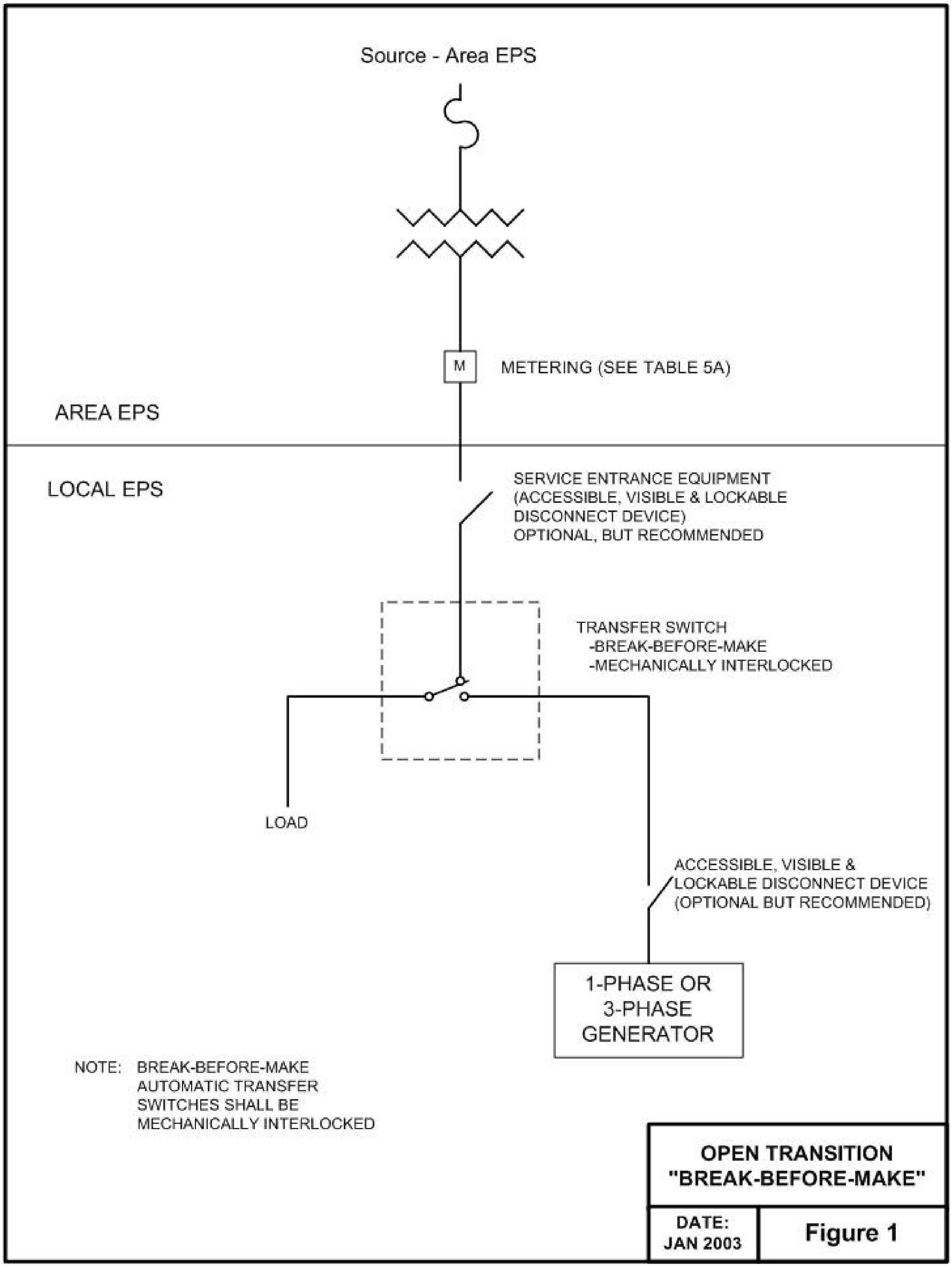
iv) Periodic Testing and Record Keeping

(1) Any time the interface hardware or software, including protective relaying and generation control systems are replaced and/or modified, the Area EPS operator shall be notified. This notification shall, if possible, be with sufficient warning so that the Area EPS personnel can be involved in the planning for the modification and/or witness the verification testing. Verification testing shall be completed on the replaced and/or modified equipment and systems. The involvement of the Area EPS personnel will depend upon the complexity of the Generation System and the component being replaced and/or modified. Since the Generating Entity and the Area EPS operator are now operating an interconnected system. It is important for each to communicate changes in operation, procedures and/or equipment to ensure the safety and reliability of the Local and Area EPSs.

(2) All interconnection-related protection systems shall be periodically tested and maintained, by the Generating Entity, at intervals specified by the manufacture or system integrator. These intervals shall not exceed 5 years. Periodic test reports and a log of inspections shall be maintained, by the Generating Entity and made available to the Area EPS operator upon request. The Area EPS operator shall be notified prior to the period testing of the protective systems,so that Area EPS personnel may witness the testing if so desired.

(a) Verification of inverter connected system rated 15kVA and below may be completed as follows; The Generating Entity shall operate the load break disconnect switch and verify the Generator automatically shuts down and does not restart for at least 5 minutes after the switch is closed.

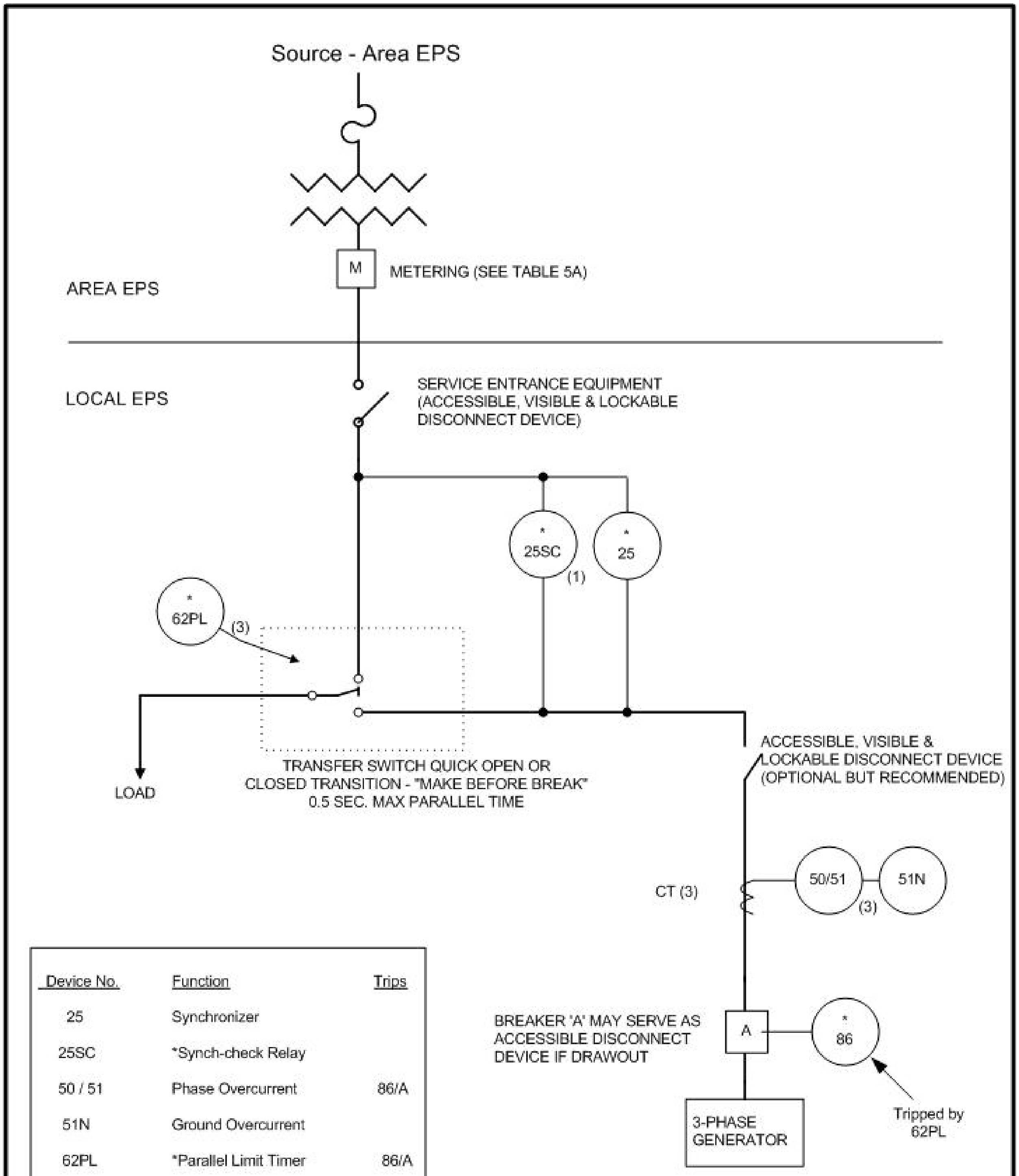
(b) Any system that depends upon a battery for trip/protection power shall be checked and logged once per month for proper voltage. Once every four years the battery(s) must be either replaced or a discharge test performed. Longer intervals are possible through the use of “station class batteries” and Area EPS operator approval.



OPEN TRANSITION "BREAK-BEFORE-MAKE"

DATE: JAN 2003

Figure 1



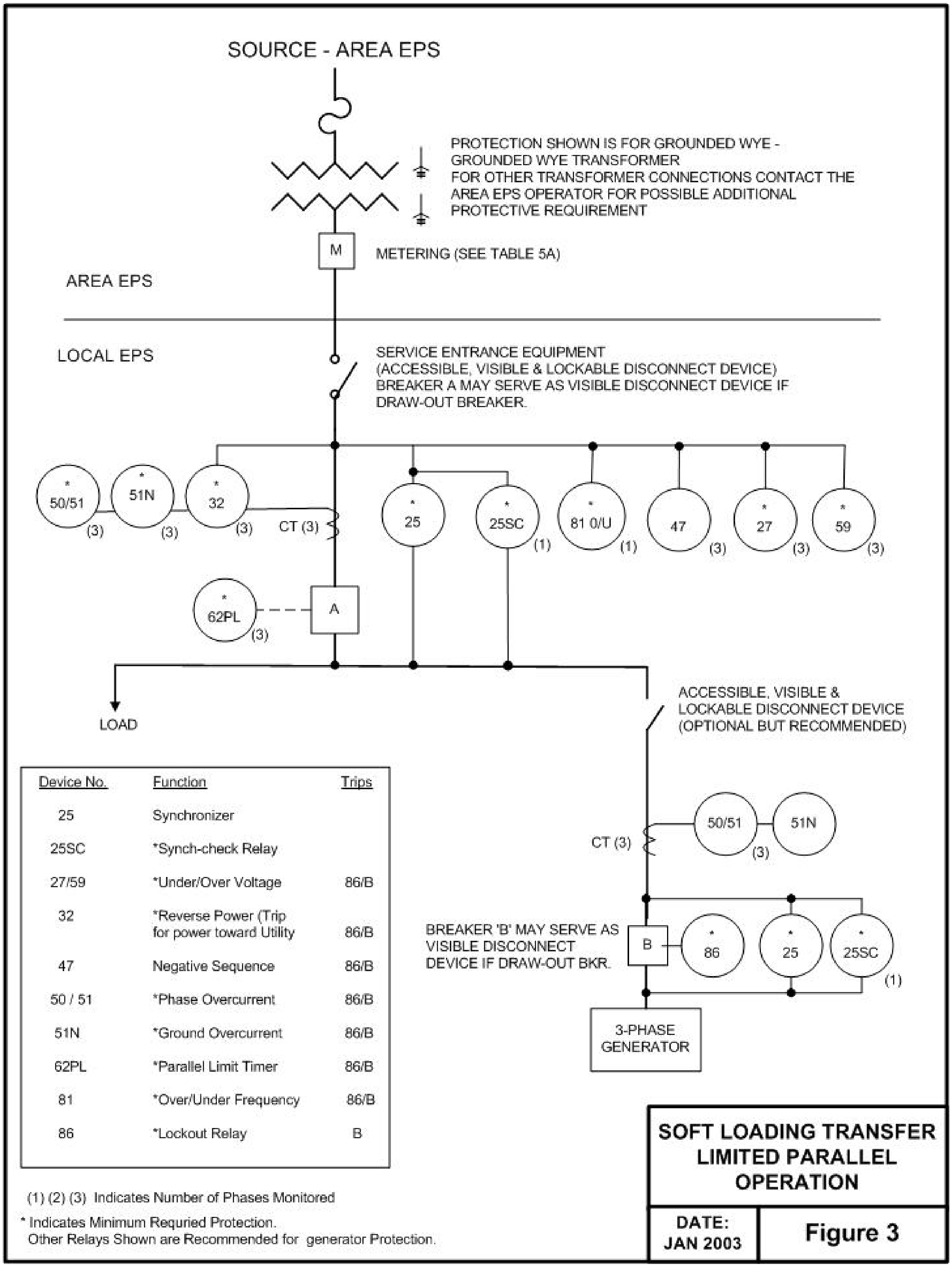
Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
50 / 51	Phase Overcurrent	86/A
51N	Ground Overcurrent	
62PL	*Parallel Limit Timer	86/A
86	*Lockout Relay	A

(1) (2) (3) Indicates Number of Phases to be Monitored

* Indicates Minimum Requried Protection
Other Relays Shown are Recommended for Generator Protection.

QUICK OPEN OR CLOSED TRANSITION "MAKE-BEFORE-BREAK"

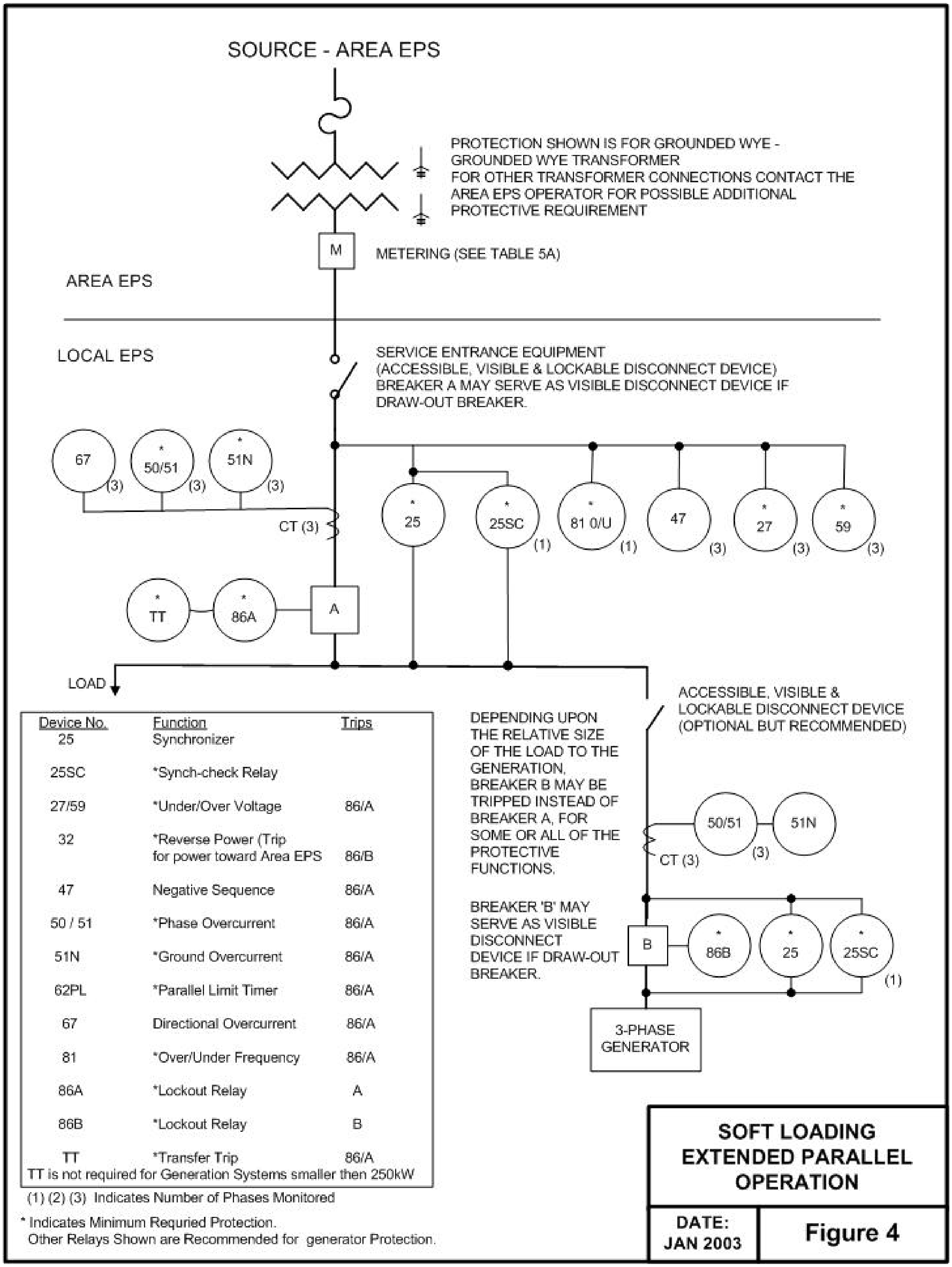
DATE: JAN 2003	Figure 2



Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
27/59	*Under/Over Voltage	86/B
32	*Reverse Power (Trip for power toward Utility	86/B
47	Negative Sequence	86/B
50 / 51	*Phase Overcurrent	86/B
51N	*Ground Overcurrent	86/B
62PL	*Parallel Limit Timer	86/B
81	*Over/Under Frequency	86/B
86	*Lockout Relay	B

(1) (2) (3) Indicates Number of Phases Monitored

* Indicates Minimum Requried Protection.
Other Relays Shown are Recommended for generator Protection.



Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
27/59	*Under/Over Voltage	86/A
32	*Reverse Power (Trip for power toward Area EPS	86/B
47	Negative Sequence	86/A
50 / 51	*Phase Overcurrent	86/A
51N	*Ground Overcurrent	86/A
62PL	*Parallel Limit Timer	86/A
67	Directional Overcurrent	86/A
81	*Over/Under Frequency	86/A
86A	*Lockout Relay	A
86B	*Lockout Relay	B
TT	*Transfer Trip	86/A

TT is not required for Generation Systems smaller then 250kW

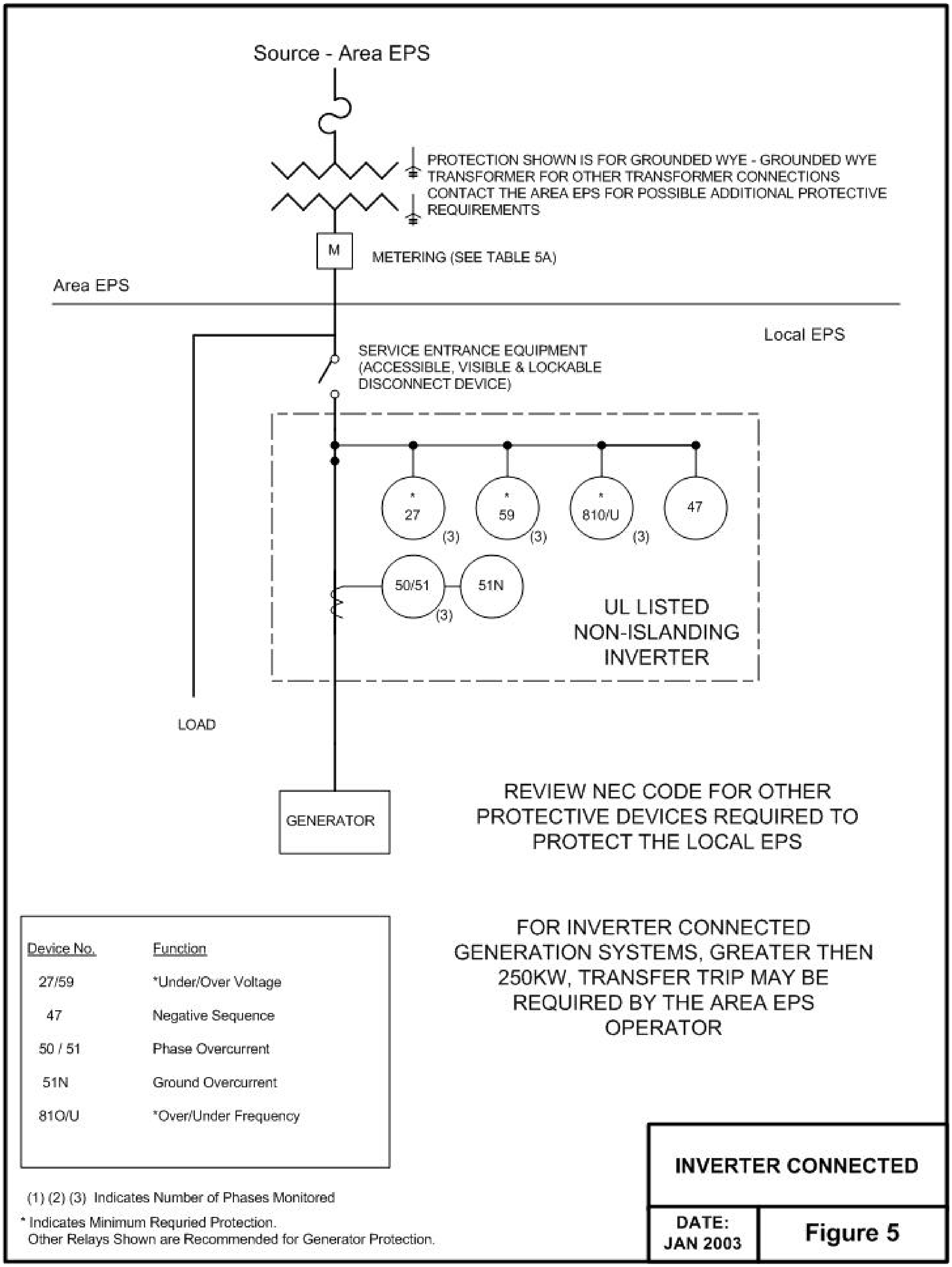
(1) (2) (3) Indicates Number of Phases Monitored

* Indicates Minimum Requried Protection.
Other Relays Shown are Recommended for generator Protection.

SOFT LOADING EXTENDED PARALLEL OPERATION

DATE: JAN 2003

Figure 4


Source - Area EPS
PROTECTION SHOWN IS FOR GROUNDED WYE - GROUNDED WYE TRANSFORMER FOR OTHER TRANSFORMER CONNECTIONS CONTACT THE AREA EPS FOR POSSIBLE ADDITIONAL PROTECTIVE REQUIREMENTS
M
METERING (SEE TABLE 5A)
Area EPS
Local EPS
SERVICE ENTRANCE EQUIPMENT (ACCESSIBLE, VISIBLE & LOCKABLE DISCONNECT DEVICE)
* 27 (3)
* 59 (3)
* 81O/U (3)
47
50/51 (3)
51N
UL LISTED NON-ISLANDING INVERTER
LOAD
GENERATOR
REVIEW NEC CODE FOR OTHER PROTECTIVE DEVICES REQUIRED TO PROTECT THE LOCAL EPS
FOR INVERTER CONNECTED GENERATION SYSTEMS, GREATER THEN 250KW, TRANSFER TRIP MAY BE REQUIRED BY THE AREA EPS OPERATOR
Device No. Function
27/59 *Under/Over Voltage
47 Negative Sequence
50 / 51 Phase Overcurrent
51N Ground Overcurrent
81O/U *Over/Under Frequency
(1) (2) (3) Indicates Number of Phases Monitored
* Indicates Minimum Requried Protection.
Other Relays Shown are Recommended for Generator Protection.
INVERTER CONNECTED
DATE: JAN 2003
Figure 5

DISTRIBUTED GENERATION

RATES

DISTRIBUTED GENERATION
RATE WORK GROUP

REPORT TO THE PUBLIC UTILITIES COMMISSION
February 3, 2003

Docket No. E999/CI-01-1023

I. INTRODUCTION

On June 19, 2002, the Commission issued an Order Organizing Work Groups and Setting Procedural Schedule. Part B of the Commission's Order states:

> *The Rate Work Group shall draft documents and guidelines for tariffs so that a person interested in developing distributed generation can apply for interconnection to any electric utility in the state with the expectation that:*
> *1) prices for electric service provided by the electric utility to the generator – including supplemental, maintenance, and backup power services – will be reasonable and non-discriminatory; and*
> *2) prices charged for power supplied by the generator to the electric utility will reflect the value of the power to the utility.*

II. BACKGROUND

Previous reports to the Commission summarized work group activities through December 2002. In all, the rate work group met nine times to develop guidelines for DG tariffs for utilities in Minnesota. Attached is the Department's summary of meetings held by the rate work group.[1] These summaries provide background for the issues highlighted in this report.

Below are the Department's proposed guidelines. These guidelines are based on the work group's discussions and reflect a large degree of consensus by the work group. However, regarding issues for which the work group could not reach consensus, the guidelines represent the Department's position. The report specifies areas where consensus was not reached. The Department recommends that the Commission allow parties to file comments and reply comments, particularly on the issues where consensus has not been reached, within a reasonable period after of the issuance of these comments.

[1] Please see previous reports, as indicated in the cover page of the attachments, for meeting summaries already provided. Also, the Department notes that the Institute for Local Self Reliance has posted information relevant to the Rate Work Group at: http://www.newrules.org/dgtariff/.

III. PROPOSED GUIDELINES

It is the Department's understanding that general consensus was reached in the following sections below:

A. Availability,
B. Qualifications,
C. List of Supply Services to be Priced,
D. Principle of Setting Rates for Services Provided by DG Customers to Utilities, and
E. Principle of Setting Rates.

On Section F below, the Calculation of Avoided Costs, agreement was reached on nearly all, if not all, of the issues. The discussion below indicates where a dispute may remain. Section G below, Standby Rates, indicates there was agreement on a number of issues but disputes may remain over distribution costs. Finally, Section H below, Credits, sets out the issues that were raised by parties, the discussion in the group, and the Department's positions. To supplement the description of positions of the parties, the Department has attached the written positions of DG owners and utilities regarding credits.

A. AVAILABILITY

1. The DG customer must be parallely interconnected to the utility distribution system.

B. QUALIFICATIONS

1. The DG facility must be an operable, permanently installed or mobile generation facility and shall be owned by the customer receiving retail electric service from the company at the same site.

2. Must buy: the utility must buy all the energy supplied by the DG customer that sells power under the tariffs to be developed.

3. Customer options: Customer may sell all the DG energy to the utility, "sell" all the DG energy to itself, or self generate part of its needs and sell the remaining energy to the utility.

4. Transactions outside the tariff: DG owners and utilities may pursue reasonable transactions outside the DG tariff. However, such transactions are beyond the scope of the work group.

C. *LIST OF SUPPLY SERVICES TO BE PRICED*
(Note: Specifics on how to price these services are discussed below)

1. Energy and capacity.

2. Scheduled maintenance service (energy, or energy and capacity, supplied by the utility during scheduled maintenance of the customer's non-utility source of electric energy supply).

3. Unscheduled outages (energy, or energy and capacity, supplied by the utility during unscheduled outages of the customer's non-utility source of electric energy supply).

4. Supplemental Service (electric energy, or energy and capacity, supplied by the utility to the DG customer, when the customer's non-utility source of electricity is insufficient to meet the customer's own load).

D. *PRINCIPLE OF SETTING RATES FOR SERVICES PROVIDED BY DG CUSTOMERS TO UTILITIES*

This principle reflects the agreement of the work group that "encouraging" DG means removing barriers rather than requiring other customers to subsidize DG.

> *Rates should reflect the value of the distributed generation to the utility, including any reasonable credits for emissions or for costs avoided on the generation, transmission and/or distribution system.*

E. *PRINCIPLE OF SETTING RATES*

This principle applies to both the prices paid for energy and capacity purchased from DG facilities and for the services provided by utilities to DG customers:

> *Rate should reflect the costs the utility expects to avoid. To the extent practical, these costs should reflect seasonal and peak/off-peak differences in costs.*

F. *CALCULATION OF AVOIDED COSTS*

The work group agreed on how to calculate avoided energy costs, and generally agreed on how to calculate avoided capacity costs. The discussion below indicates an area where a dispute regarding capacity costs may remain.

1. *Avoided Energy Costs*

   Using a production model the following steps are used to calculate the marginal energy rates:

   1. System-wide hourly marginal energy costs are calculated for each hour of the future year.

   2. Based on (1), the average on-peak and off-peak marginal energy costs are calculated for each month.

   3. The on-peak monthly rate is set at the average monthly on-peak marginal energy costs. The off-peak monthly energy rate is set at the average monthly off-peak marginal costs. Thus, there are 24 rates set for the year, with an on-peak and off-peak rate set for every month.

   4. A trial period is proposed to see whether, in practice, utilities are able to forecast these energy prices sufficiently well. Depending on the trial results, a lump sum true-up may be used at the end of each year to reflect the difference between actual and estimated energy bills.

2. *Avoided Capacity Costs*

   The work group largely agreed on the general methodology of calculating avoided cost, which is:

   1. Calculate the installed capital cost plus fixed O&M costs plus startup costs ($/kW-year). If the next (marginal) unit is from a competitive bid, the utility must estimate these costs and fully defend the estimate.

   2. Calculate the levelized Annual Revenue Requirements (LARR) ($/kW-year).

   3. Divide the amount in (2) for the next year by twelve to get the capacity marginal costs ($/kW-month).

   4. These marginal costs must be escalated annually by the expected inflation rate.

   The group also generally agreed on the following issues regarding the calculation of avoided capacity costs:

   a. The need for capacity is established in the utility's most recent integrated resource plan (IRP).

   b. Capacity payments should be made for the total DG capacity that is accredited by MAPP's URGE test, regardless of when the power is delivered to the system.

c. The normal “life” of a capacity addition is assumed to be 30 years.

d. If the contract to purchase power from a DG source begins at the time the utility needs the capacity, then the full capacity payment is made, adjusting only as needed for the length of the contract (i.e., there is no discount for adding capacity sooner than it is needed).

The attached notes dated December 4, “Adjustments to Capacity Payments,” provides the formula to adjust the avoided capacity cost payment for the timing of the contract and the length of the contract. Regarding “a” above, utilities wanted to recognize need only if the Resource Plan shows a need in the next five years. However, the formula in the Attachment already significantly discounts and recognizes the lower payments to be made for capacity added prior to when a need for a larger facility may be indicated. Using this approach results in a reasonable payment for adding small amounts of capacity which may more closely reflect the incremental growth of load. As such, the Department proposes the following criterion:

> *The need for capacity is established in the utility’s most recent Integrated Resource Plan (IRP). A need exists if the utility shows a deficit at any year of the 15-year panning period.*

G. STANDBY RATES

Standby services include scheduled and non-scheduled outages and supplemental services. The work group discussed general issues, as indicated in the meeting notes for January 8 and the end of January 22. The Department notes that, while there was consensus on a large portion of these issues, work group participants may disagree with certain aspects discussed below, particularly distribution issues.

1. General

There was overall agreement about the following general issues:

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

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.

2. Firm Service

There was not agreement on how to price firm or non-firm standby services. As indicated in the attached notes, DG customers wanted lower charges for standby distribution services. The following is the Department's recommended guidelines; it is not expected to be a consensus:

a. *Generation* (both energy and capacity): The monthly reservation fees are equal to the percentage of the planned reserve margin of the utility times the applicable energy and capacity tariffed rates. As such, there is a discount of 82 to 85 percent of the generation charge.

b. *Transmission*: The monthly charges are equal to the utility's planned reserve margin percentage times the applicable transmission charge. Thus, there is a discount of 82 to 85 percent of the transmission charge.

c. *Bulk Distribution*:[2] The monthly charges equal the monthly charge under the applicable distribution charge. That is, there is no discount in the "bulk" distribution charge.

d. *Non-Bulk (Local) Distribution*: The monthly charges equal the monthly charge under the applicable distribution charge. There is no discount in the "local" distribution charge.

To summarize, the energy and transmission monthly reservation fees are discounted by between 82 to 85 percent (100 percent minus the planned reserve margin percent). However, there is no discount for distribution charges. The Department recommends this approach because it reflects the extent to which utilities are able to avoid costs. Moreover, it is an approach based on readily available information.

3. Non-Firm

As noted above, some work group participants may disagree with the proposal below for pricing non-firm standby distribution services. However, this approach is based on reflecting cost-causation and the ability of the utility to avoid costs.

a. *Generation* (energy and capacity): There are no monthly reservation fees for energy and capacity for a non-firm DG customer.

b. *Transmission*: There are no monthly reservation fees for transmission for a non-firm DG customer.

c. *Bulk and Non-Bulk Distribution*: The monthly rates equal the monthly charge under the applicable distribution charges. That is, there is no discount on the distribution charge.

[2] DG customers proposed to separate the distribution system into two sub-components: bulk and local.

4. *Physical Assurance Customer*

Due to the proposed option to pay up-front for stranded distribution facilities, there was apparently more agreement on pricing standby services for physical assurance customers.

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 cost of the mechanical device, which must be reasonable, is to be paid by the DG customer.

Like a non-firm customer, a physical assurance customer would not pay a reservation charge for generation or transmission service. Moreover, physical assurance customers would have an option either to pay up-front for stranded distribution facilities that they will not use or to pay for distribution service, through the standby charge, for the entire amount of load.[3]

5. *Maximum Size to Avoid Standby Charge*

The notes in the Attachment regarding the summary of the January 8, 2003 meeting provide the basis for the Department's following recommended guideline:

> *A DG facility of 100 kW or less is exempted from paying any standby charges.*

As indicated in the notes, some of the work group's participants (utilities) want to limit the exemption to a size of 40 kW or less. The Department agrees that, on pure economic principles, the 100 kW's exemption is not justified. However, the Department supports this principle as a way to "encourage" the installation of DG facilities in Minnesota. This proposed guideline is a recommended compromise for the Commission to consider. This proposal expected to have no significant impacts on the costs to other ratepayers. We also recommend that utilities keep track of the costs of this 100 kW limit in practice. If the costs are significant, this issue may be revisited in the future.

H. CREDITS

1. *General*

Credits should be given to a DG customer if the installation of a DG facility reduces the utility's costs of providing the service. These lower costs could be generation, transmission or distribution related costs.

[3] For example, a customer with 5 MW of DG who can physically guarantee that they would not use more than 2 MW of standby power could pay up-front for the abandoned 3 MW of distribution facilities or pay the monthly distribution charge on 5 MW.

2. *Distribution Credits*

The work group discussed this issue in the January 22, 2003 meeting. The main dispute regarding this issue was the amount of information that the utilities must provide to all the potential DG owners regarding the utilities' distribution system needs, and who should bear the cost of the needed studies (utilities or the DG owners). At the meeting, the Department indicated to the work group that we would recommend guidelines to the Commission regarding distribution credits. On part "a" below, the work group reached consensus. Parts "b" through "d" below represent the Department's recommended guidelines:

a. Distribution credits to a DG customer should equal the utility's avoided distribution costs resulting from the installation of a DG facility.

b. 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.

c. Upon receiving a DG application, the utility will perform an initial screening study to determine if the DG project has the potential of receiving distribution credits. The DG customer is responsible for the cost of such a screening study.

d. If the utility's study shows that there exists potential for distribution credits, the utility must, at its own cost, pursue further study to determine the distribution credit, as part of its annual distribution capacity study.

3. Diversity Credit

In the January 8, 2003 meeting, the group discussed whether DG facilities should be given a credit for providing diversity, in the form of many small plants as opposed to fewer large plants, to the system. Some work group participants argued that, due to their small sizes, DG facilities do not require utilities to maintain the same reserve margin as they do in their Integrated Resource Plans. Therefore, the reservation fees for standby services should be further discounted. The Department notes that, regardless of the facility size, utilities must have a sufficient reserve margin to provide standby services and avoid MAPP imposed penalties. As such, the Department recommends that the Commission adopt the following guideline:

> *No additional diversity credits for energy and capacity should be given to DG customers who contract for standby service.*

4. Line Loss Credits

The work group discussed whether DG facilities should be given a credit for line losses. This discussion is summarized in the notes for the January 22 meeting. The work group appears to agree that no additional line loss credits (above the credits already included in the avoided cost calculations) should be paid to a DG customer with the following exception: A DG customer may request the utility to provide a specific load loss study and receive additional line loss credits if the study supports such credit. The DG customer is responsible for the study cost regardless of the study's outcome.

5. *Renewable Credits*

As indicated on the attachment, the group discussed whether a credit for a renewable facility should be applied and, if so, how to calculate such a credit. This discussion referenced the green-pricing premiums that all utilities currently have in place. The Department's position is that a DG customer who installs a renewable DG facility should be paid the avoided cost of "green power" to the extent that installation of the DG facility allows the utility to avoid the need to purchase "green power" elsewhere. Otherwise a renewable DG facility should be paid the utility's regular avoided costs as discussed earlier in these comments. This approach is based on the principle of setting rates at avoided costs.

However, as indicated in the notes for the January 22 meeting, this issue may be somewhat complicated by the renewable energy objective. Given the statutory requirement that utilities make a "good-faith effort" to purchase specified levels of renewable energy, the question for the Commission to decide is whether it is reasonable for utilities to pay a credit for renewable power at the approved green-price premiums even if the utility does not need the green power. Parties have agreed to provide arguments to the Commission regarding this policy question.

6. *Emission Credits*

a. Tradable Emissions: For tradable emission such as SO2, if a low emission DG facility allows the utility to capture the value of the emission credit, then the DG owner should receive the credit revenues. The work group agreed on this guideline.

b. Non Tradable Emissions: The Department proposes that DG owners should receive emission credits for non-tradable emissions. 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.

Note: Part "b" above represents the Department's position, but some of the work group's participants may not agree with it. The rational for "b" is that emission costs are considered by utilities in their resource selection process and, if a resource is selected that would result in higher costs absent emission costs, the owner of this resource is compensated for this lower emission resource. Therefore, renewable DG facilities should be compensated for producing lower emissions in this same manner.

However, it should be clear that a DG customer may get green credit or an emission credit, but not both.

7. Reliability Credits

This issue was discussed in the January 22 meeting (at the end). Given that discussion, the Department concludes that DG owners should receive no reliability credit beyond what is already incorporated in the standby tariffs. Since the utility must maintain its reserve margin regardless of the performance factor of the DG facility, such a credit is not appropriate.

BACKGROUND DOCUMENTS FOR RATE WORK GROUP

I. MEETING NOTES

Number	Date	Location of Notes
1	August 7, 2002	Final Report*
2	September 4, 2002	Final Report*
3	September 18, 2002	September 19 Update
4	October 9, 2002	December 19 Update
5	October 30, 2002	December 19 Update
6	November 18, 2002	December 19 Update
7	December 11, 2002	December 19 Update
8	January 8, 2003	Final Report*
9	January 22, 2003	Final Report*

II. PROPOSED ADJUSTMENTS TO CAPACITY PAYMENTS: FINAL REPORT

III. CREDIT PROPOSALS: FINAL REPORT

- Original proposal by DG customers December 20, 2002
- Supplemental proposal by DG customers January 17, 2003
- Response by utilities January 20, 2003

IV. OTHER INFORMATION

For a list of documents exchanged during the work group's efforts, please see the website maintained by the Institute for Local Self Reliance, at http://www.newrules.org/dgtariff/.

DG RATE GROUP TARIFF MEETING
August 7, 2002
Docket No.E999/CI-01-1023

Summary of Events

The Work Group agreed that:

1. The Group will use the Department of Commerce agenda proposed in the July 17, 2002 letter to potential participants as the guideline for a working agenda. The items listed in the DOC agenda are as follows:

    A. Determine which modes of operation should be covered under the tariff (i.e., Continuous Parallel interconnection, Momentary Parallel interconnection [few minutes at most], Isolated non-grid connected operation).

    B. Which other services should be covered under the tariff (such as Standby power Supplemental power, and Maintenance power).

    C. Determine the principles to be used in setting the appropriate rates (i.e., avoided costs or other methods).

    D. Procedural issues, such as time line, minutes of the meeting, etc.

2. The Group will generally meet every three weeks. To accommodate requests by participants, the next meeting will be on Wednesday September 4th, at which time a subsequent meeting date will be set.

3. The Group will need to clearly define Supplemental service, Standby service, and Maintenance service to avoid possible confusion during future discussions. The participating utilities agreed to provide their own existing definitions to the DOC around August 15th.

4. The Group began to discuss the first two items (A) and (B) in the agenda. Regarding (A) *Determine which modes of operation should be covered under the tariff (i.e., Continuous Parallel interconnection, Momentary Parallel interconnection [few minutes at most], Isolated non-grid connected grid operation)*, the Group decided that the following Methods of Operation should be included in the future discussions:

    a) Isolated (non parallel or non synchronized)
    b) Parallel
        i) Buy-all sell-all setup
        ii) Supplemental only
        iii) Supplemental with additional output being sold to the utility
    c) Momentary Parallel

5. Regarding (B) *Which other services should be covered under the tariff (such as Standby power, Supplemental power, and Maintenance power)*, the Group decided that other services include, at a minimum:
   a) Interconnection Services
      Paul Lehman (Xcel) will provide a draft Interconnection Services definition
   b. Supplemental service
   c. Standby service
   d. Maintenance service

The Group will discuss at the meeting whether any other items need to be added to this list.

The Group set the following for the __September 4th__ agenda:

1. Finalize the list of other services to be covered under the tariff (including discussion of definition of interconnection services).

2. Determine the principles to be used in setting appropriate rates.

Miscellaneous:

The Group agreed all interested parties should attempt to:

i) Gather as much helpful information as possible about DG rate issues. This includes searching such sources as NARUC, the Internet, regulatory commissions of other states, and FERC.

ii) Assist one another by sharing information, and opening up channels of communication. The DOC will attempt to secure better meeting facilities to encourage better discussion among participants.

iii) Accomplish as much as possible between meetings to ensure efficient use of meeting time.

All attending parties were asked to provide the name(s) of their representative(s), and an e-mail address and/or phone number where they can be contacted to the DOC. Kate O'Connell (DOC) has provided a complete e-mail/phone list to all interested parties. The DOC asks that anyone wishing to make an addition and/or amendment to this list contact Kate O'Connell at kate.oconnell@state.mn.us. If you suggest the name of a person other than yourself, please ensure that the person wishes to be added to the list. Also, we note John

Bailey of the Institute for Self-Reliance has developed an e-mail group for discussion of items. As such, please contact John at bailey@ilsr.org for any changes to that list.

The DOC would like to inform the people on service list that the only way to get e-mail interim reports on the workgroup from the DOC is to contact the DOC (as identical above), and ask to be on the e-mail list. However, all parties on the service list will still receive official documents by mail simply by being on the service list. (Anyone who wishes to remove their name from the official service list may contact the Minnesota Public Utilities Commission.)

The DOC would like to thank everyone for attending the first meeting. We look forward to working with the Parties in creating principles for developing DG tariffs.

DG RATE GROUP TARIFF MEETING

September 4, 2002

Summary

In defining certain aspects of distributed generation, the group discussed fundamental issues regarding distributed generation. While the group is looking forward to discussing the ratemaking principles, it was clear from the discussion that it will be necessary to have a common understanding about what the basic concepts are to avoid or minimize the need to sort out misunderstandings about definitions in the future. In addition, the discussion indicated some helpful issues, such as that there may be different types of certain services that a utility could provide to DG customers.

A. Services Provided by Utilities to Distributed Generators

- Prior to the meeting, Xcel provided a draft outline of a breakdown of Distributed Generation Services. This list is attached. The group focused on defining the services listed under "Supply Services" as follows:

    1. Scheduled maintenance service: Energy, or energy and capacity, supplied by the utility during scheduled maintenance of the customer's non-utility source of electric energy supply.

    2. Unscheduled Outages: Energy, or energy and capacity, supplied by the utility during unscheduled outages of the customer's non-utility source of electric energy supply.

       (Note: In defining the scheduled and unscheduled services above as the provision of energy or energy and capacity, the group left open the option of the utility providing firm or interruptible services.)

    3. Supplemental service: The group agreed that the definitions offered to date do not adequately define supplemental service, but did not come to consensus on how to define this service. **Group members were assigned the task of bringing a definition of supplemental service to the next meeting**.

- The rate workgroup noted that the "black start" service that may at times be provided to distributed wind generation is one of the services that would need to be addressed in defining ancillary services.

- The rate workgroup noted that it will be necessary to coordinate with the technical workgroup to ensure that interconnection services are fully identified. To facilitate this coordination, **Dan Tonder (Minnesota Power) agreed to get the list of interconnection services developed to date by the technical workgroup. After**

reviewing this list, the rate workgroup can decide what further services (including those on the attached list or any other services) need to be defined by the rate workgroup.

- The group also noted that, in defining interconnection services, it will be necessary to distinguish between transmission and distribution components, largely to address FERC issues.

- It was noted in the group that distribution lines to service only the DG customer should be classified under interconnection services, while distribution lines serving other customers in addition to the DG customer should be classified under delivery service.

B. For Next Meeting

The Group set the following agenda for the September 18th agenda:

1. Define supplemental services.

2. Determine what interconnection services need to be defined in addition to the definitions in the technical workgroup.

3. Begin discussion of principles to be used in setting appropriate rates.

As always, we encourage parties to work together and bring as much consensus as possible to the meetings.

C. Time For Next Meeting

It has been requested that the group meet for an extra hour at the next meeting. So the time and place will be:

Wednesday, September 18, 9:30 to 12:30
Minnesota Department of Commerce (85 7th Place East, Suite 500)

Xcel's proposed list of Distributed Generation Services

Interconnection Services

Services associated with getting the DG facility connected to the system

- Interconnection studies
  - Energy Resource
  - Network Resource

- Facility construction
  - Radial/Direct Assignment facilities
  - Network facilities

Delivery Services

Services associated with the use of the distribution and/or transmission system

- Transportation of power

- Ancillary services

Supply Services

Services associated with generator output and/or serving load

- Standby service

- Supplemental service

- Maintenance

- Surplus power purchase

DG RATE GROUP TARIFF MEETINGS

January 8, 2003

Docket No.E999/CI-01-1023

I. Summary of Discussion

A. Procedural Issues

The last meeting of this workgroup will take place on January 22, 2003. The Department's Report will be filed February 3, 2003. This report will include the notes from meetings along with the Department's positions on issues. The Department intends to recommend to the Commission that parties have an opportunity to provide comments on the report after it is filed.

B. Standby Power When There is Physical Assurance That DG Facility Will Not Take Power

1. Generation Credit to Standby Charge

There was general agreement that, when there is physical assurance that the DG facility will not take power, then:

a) The utility will not be required to provide power for whatever amount that the DG owner and utility mutually agree (contract) will not need to be provided.

b) The generation credit to the standby charge should be equal to the generation in (a) above that the DG facility will not use.

c) The cost of the device needed to ensure that the DG facility will not take power from the utility system should be borne by the DG owner, but should be a reasonable cost.

2. Maximum Facility Size to Avoid Standby Charge

The question was raised about how large a facility could be and still be exempted from paying the Standby charge. DG Owners wanted to allow larger facilities to be exempt from this charge, while Utilities wanted to use the 40 kW limit in federal rules for Qualifying Facilities.

Agreement was not reached on this issue. However, the Department noted that, while strict economic principles would lead to the conclusion that 40 kW should be the limit, this may be an area where a compromise could be used. The Department suggested a compromise of using the 100 kW limit that, until recently, was in Xcel's tariff and see how much activity there is for facilities between 40 kW and 100 kW. It should be clear that this issue is a compromise and should be reviewed for its effects in practice. It is expected that any avoided revenues from Standby Charges would be insignificant but this assumption should be checked in practice. If this approach proves to be a problem in practice, such problems should be simple to mitigate.

3. Transmission and Distribution Credit to Standby Charge

In addition to the generation credit when there is physical assurance that the DG facility would not take electric service above an agreed-upon level, DG owners argued that they should receive a credit in the Standby Charge for the transmission and distribution components of the charge.

However, the counter-argument was made that, once distribution facilities are built, a physical assurance that the facilities will not be used should not result in a distribution credit. Once distribution facilities are built, they are built, and the customer for whom the facilities were built should pay for the cost of the facilities. (However, as noted below, there was some room for discussing a "bulk distribution credit" in certain circumstances.)

However, there may be a valid argument that there is some diversity in the transmission facilities and that a credit may be reasonable. In fact, according to Xcel, Xcel's Standby Charge already gives firm DG customers a credit of 82 percent of transmission costs to reflect that their use of the transmission system is less than other customers. Non-firm DG customers receive 100 percent credit for generation and transmission.

Based on this discussion, it was proposed that, if there is physical assurance that a DG customer would not take service above an agreed-upon level, there would be 100 percent credit for transmission and generation.

Dakota Electric, which is a distribution-only cooperative, noted that it would have difficulty with giving a transmission credit.

It was noted that the distribution system may be able to be separated into a bulk and non-bulk level, and that credits may be appropriately given to DG Owners for the bulk portion of the distribution system. This issue was left open for further discussion.

The discussion then moved to credits for non-firm DG customers. The difference between non-firm and physical assurance DG customers is as follows:

Non-firm:	the DG customer takes service only when the utility authorizes use
Physical assurance:	the DG customer never takes service above an agreed-upon level

It was proposed that the DG customer could choose either to pay up-front for stranded distribution facilities or to pay in the Standby Charge for the distribution facilities. The replacement cost, depreciated, would be used to calculate stranded costs. Theoretically, either approach should be fair to both the customer and the utility.

The group began to discuss giving credits to DG customers who can help the utility avoid new distribution or other costs by locating in an area that would provide relief for the utility system. It was acknowledged that this idea had merit and should be explored. (This is the DG Owners' "Red, Green and Yellow" proposal.)

DG Owners proposed that the credits discussed for circumstances where DG Owners give physical assurance that they would not use the utility system above an agreed-upon level also be given in cases where there is not physical assurance. Utilities disagreed with this proposal.

Xcel's current tariff uses the following Credits to the Standby Charge:[1]

:

Category	Physical assurance	Firm	Non-firm
Generation	100%	82%	100%
Transmission	100%	82%	100%
Bulk Distribution	0%*	0%	0%
Non-bulk Distribution	0%*	0%	0%

* Customers would have an option to pay up-front for stranded facilities

Xcel noted that firm customers should still pay for 18% of generation and transmission facilities to reflect the utility's requirement to have a reserve margin for firm customers.

DG Owners noted that, with the diversity offered by DG facilities, and the smaller units with lower forced outage rates, a lower reserve margin, say 8% may be more appropriate for DG facilities.

However, utilities noted that, while the reserve margin may be different if the entire system were made up of smaller units, the reserve margin is set for entire system. However, the costs of a system made up of smaller units may also be higher, so 8% of a higher cost system may be equivalent to 18% of a lower cost system.

Beyond this hypothetical discussion, it was noted that any standby customer imposes costs on the current system by requiring standby service to be available.

[1] Note: The table provided in the meeting showed the amounts DG customers should pay, e.g. 18% of transmission facilities paid by firm customers. This table shows credits to fit with the discussion of credits.

The Department noted that this issue was before the Commission long ago in a proposal pertaining to standby service. The Department intends to review what was discussed at that time.

It was generally acknowledged that this was an issue that was not likely to result in agreement at this point in the group.

II. Request for Comments

To facilitate discussion for the last meeting, participants were asked to provide their comments on the credit issues outlined in comments provided by DG Customers prior to this meeting and handed out in the meeting. (Includes “Red, Green, Yellow” proposal, line losses, renewable credits, etc.) Group participants were asked to provide these comments by **January 17**:

III. Next Meeting

The next meeting is set for:

Wednesday, January 22, <u>9:30 to 12:30</u>
Minnesota Department of Commerce (85 7th Place East, Suite 500)

DG RATE GROUP TARIFF MEETINGS

January 22, 2003

Docket No.E999/CI-01-1023

I. Summary of Discussion

A. Procedural Issues

This was the last meeting of this workgroup. The Department's Report will be filed February 3, 2003. This report will include the Department's positions on issues. The Department intends to recommend to the Commission that parties have an opportunity to provide comments and reply on the report after it is filed.

B. Credits

1. Locational Distribution Credit for Constrained Distribution Areas

<u>Proposal by DG Owners</u>:
DG owners proposed a "Locational DG Distribution Credit" for the DG Tariff. Under this proposal, the utility would have to segregate its service territory into 3 DG territories based on capacity constraints and/or costs for system upgrades. DG owners proposed the following for these red/yellow/green areas:

"Red" - a very large benefit from DG installation [very constrained areas with high upgrade costs, which may be about 5-10% of its territory];

"Yellow" - a moderate benefit from DG installation [moderately constrained areas, maybe 15-20% of territory]; and

"Green" - a general benefit [the rest of the service area].

DG owners proposed that the Commission determine the credit rate within each of these areas, based on the avoided distribution system upgrade costs that the utility avoids or defers because the DG has been installed in that location. The DG customer and utility would share these costs.

<u>Response from Utilities</u>:
In response, the utilities acknowledged that a tiered locational DG distribution credit would recognize "that the benefit from installing DG will vary depending on local circumstances." However, the utilities' concern is that "identifying, segregating and updating electric utility service territory into these three tiers would be extremely difficult to accomplish from both an engineering and administrative perspective."

Rather than setting up a red/yellow/green system that would require the utilities to study their entire distribution system, utilities suggested using the results of the up-front system study required for each DG installation to identify the potential distribution credits/costs for each DG proposal. Utilities noted that evaluating potential distribution credits/costs in this manner would not significantly delay the study and review process and would provide accurate accounting of site-specific credits/costs for each installation.

Discussion in Group

The workgroup noted that the trade-off on this issue is between a) providing a reasonable amount of information to encourage DG facilities to locate in areas that would be better for the utility system and b) keeping the costs of such information reasonable. Requiring utilities to study their entire distribution system would likely be too costly. However, relying only on the results of the interconnection study would not provide enough information up-front to encourage new DG facilities to locate in better areas. The group discussed various ways of balancing these concerns.

One option discussed was to study a few limited areas where the distribution system may be constrained. Another option was for the utilities to provide their proposed budgets for construction on their distribution system to indicate places where a DG facility might delay the need for additional investment by the utility. Utilities indicated interest in this proposal, but also noted a few issues to consider: a) construction budgets can change, b) making construction budgets public might reduce flexibility in planning construction, and c) DG facilities may not always be able to help utility avoid investment. Nonetheless, utilities indicated their preference for this proposal over the proposal to color code the entire system. This approach would, in effect, identify potential “red” areas.

Another option (that could be used in conjunction with the option above) was for DG owners to consider releasing to other potential DG owners the results of their interconnection study. This approach would provide limited but possibly useful information. Some DG owners indicated concern about having such data public while others encouraged DG owners to make the information available.

Finally, utilities were encouraged to consider making available other sources of data that they already collect such as peak load of transformers or loading outage data.

The next aspect discussed was the level of credits to be provided. DG owners stated that “the distribution constrained credit should be valued on how the DG mitigates utility investment.” The utilities agreed and stated that the proposed credits should be given only where benefits are received. However, DG owners wanted to know in advance that they would receive credits. DG owners stated that the credit could be a short-term payment until the utility upgrades the distribution zone, or a long-term payment if it completely offsets utility investment.

There was discussion about perceived differences in “investments” and “avoided costs.” Utilities stated that putting a DG facility in a constrained area doesn’t guarantee that the utility will avoid costs. The discussion ended with the utilities and DG owners agreeing to disagree on this issue.

2. Diversity Credits

Diversity credits were discussed in the 8th meeting (near the end) and so were not revisited in this meeting.

3. Line Loss Credits

DG owners proposed that DG facilities be given a credit for decreasing line losses on the utility system. Utilities responded that the credits proposed for generation and transmission already include line losses. However, utilities noted:

> …there may be specific circumstances where the location and operation of a DG facility could provide additional generation and transmission line loss benefits. Accordingly, we recommend that the identification and quantification of such additional line loss credits be included in the up-front study as we proposed above for identifying Locational DG Distribution Credits.

DG owners wanted instead to use the average line loss for the system to determine the credit for line losses, and to allow DG owners to decide whether they want to pay more to have the study of line losses done to receive an extra credit. Utilities argued that this approach would result in having only those DG facilities that were likely to result in higher losses ask for the additional study. The Department acknowledged this likely outcome but indicated that the practical effect of this issue is likely to be small.

4. Renewable Credits

DG owners proposed that DG facilities that use renewable fuel be given a credit equal to the premium built into "green prices" (after marketing and administrative costs are deducted). DG owners also proposed that, if credit trading is established in the future, DG facilities with renewable energy should be allowed to participate in that market.

The issue of trading was not discussed extensively since there currently is no trading. However, at least one DG owner wanted to have a statement in writing that, if utilities have not paid for a green credit, they haven't bought it.

The group discussed two approaches to setting such a credit: using strict avoided costs or using a "market" approach. Under the avoided costs approach, the credit would be paid if the DG facility allows the utility to avoid purchasing "green" power from another source. Under the "market" approach, the DG facility would be paid the credit equal to what the utility negotiated for green power, regardless of whether the utility needed to buy the renewable power for its green pricing program.

Utilities indicated that they would have no problem adding DG power to their system, rather than purchasing it elsewhere, provided that their customers want the renewable power. However, utilities are hoping to have the premium for "green" power to decrease over time which may reduce the renewable credit for renewable DG. DG owners seemed to indicate that they, too, expected green premiums to decrease over time.

The group discussed the renewable energy objective and noted that the objective was not a mandate to purchase renewable power. Rather, utilities are required to make a "good-faith effort" to meet the renewable goals set out in statute (216B.1691). The question for the Commission to decide is whether, given the good-faith effort language in statute, it is reasonable to set the credit at the green-price premium even if the utility doesn't need the green power. Group participants agreed to address their positions on this issue in comments before the Commission.

5. Emission Credits

There were two aspects to this discussion. First, DG owners noted that some emissions are currently be traded in the market. DG owners propose, then, that if a utility captures the value of credits from a DG facility with low emissions, DG owners should get the credit revenue. There did not appear to be opposition to this idea.

Second, DG owners wanted to receive a credit for emissions costs avoided by the utility if the DG power has fewer emissions that the utility's emissions. It wasn't clear how the amount of credits would be calculated. A few options briefly discussed were to calculate the credits compared to the next unit the utility would have otherwise brought on-line or credits the utility avoids having to purchase. The DG owners also noted that, if a renewable energy project seeks an emissions credit, it should not also be eligible for the green credit.

6. Reliability Credits

DG owners proposed that they be given what they termed a reliability credit, described as follows:

> The reliability credit should be given on the basis of the DG system availability during utility's critical peak time. As part of the peak interruptible tariff, electric utility provides tiered controllable demand (kW) discounts to the peak interruptible customers on the basis of their performance factors (PF) where the higher performance factor customers attain more discounted controllable demand charges. Since the DG system operates continuously, it has a higher system reliability or performance factor. Comparatively, some DG facilities may have a higher performance factor than other DG facilities.
>
> The current firm standby charges do not differentiate the system availability or performance factor within the DG class of customers. We recommend a similar tier approach should be established to discount the firm standby charges on the basis of DG reliability. Thus, the reliable DG systems should get discounted standby charges.

Xcel responded that their firm standby tariff already captures the reliability issue by using a deadband and grace period. The maximum amount the DG owner would pay is the full retail rate; the minimum is 18% of retail, which reflects that the utility must have capacity available when needed (see notes from previous meetings).

However, DG owners did not want to pay the 18% level. There was not agreement on this issue.

7. Bulk Distribution Credit

DG owners proposed that they be given a credit for relieving congestion on the “bulk distribution system” in a manner that is similar to what they receive for relieving congestion on the transmission system. Utilities responded that they have not divided their distribution system into “bulk” and “local.” However, the study of the individual DG proposal would indicate the extent to which there are benefits on the distribution system.

Adjustments to Capacity Payments

(December 4, 2002)

Enclosed is an explanation of the adjustments the Department proposes to the calculations of avoided capacity costs to accommodate for (a) the timing of the contract and (b) the length of the contract.

There are two timing issues to be considered regarding power purchase contracts. First, if a contract for purchase of power starts earlier than the need for capacity, the time value difference between the contract start period and the period when the capacity is needed must be accounted for. Second, the difference in the length of time that the power purchase contract provides capacity and the time for which the capacity is needed must be considered. The equation that addresses both issues is as follows:

(1) $$A2 = \frac{(1+i)^m - 1}{(1+i)^n - 1} * \frac{(1+i)^{n-a} - (1+e)^{n-a}}{(1+i)^m - (1+e)^m} * A1$$

Where:

A1 = Levelized annual value of a capacity purchase at the time of need.

A2 = Levelized annual value of the capacity being paid for in a power purchase contract.

m = Expected lifetime of ordinary (alternative) future capacity addition.

n = Length of power purchase contract.

i = Utility Cost of Capital.

e = Escalation rate affecting value of new capacity additions.

a = Length of time between beginning of contract and time of need for capacity.

The first factor:

$$\frac{(1+i)^m - 1}{(1+i)^n - 1}$$

recognizes the difference between the length of the power purchase contract and the lifetime of the alternative capacity addition. The second factor:

$$\frac{(1+i)^{n-a} - (1+e)^{n-a}}{(1+i)^m - (1+e)^m}$$

recognizes the difference between the time the power purchase contract is executed and the time at which capacity is actually needed.

For example, if m=n (that is, the contract length equals the lifetime of alternative capacity addition) and a=0 (the contract starts at the time additional capacity is needed) equation (1) becomes:

$$(2) \qquad A2 = 1 * \frac{(1+i)^n - 1}{(1+i)^n - 1} * \frac{(1+i)^n - (1+e)^n}{(1+i)^n - (1+e)^n} * A1 = 1 * 1 * A1 = A1$$

That is, the levelized annual value of the capacity paid for in a power purchase contract equals the levelized annual value of the alternative capacity purchased at the time of need. So, if the DG contract provides capacity when it is needed for the same length of time as the alternative capacity, there is no need to adjust the avoided capacity cost per kW. That is, the DG owner should be paid the same amount per kW that the utility would pay for the alternative capacity.

If a=0 (the contract starts at the time additional capacity is needed) but $m \neq n$ (the contract length differs from the lifetime of alternative capacity), then equation (1) becomes:

$$(3) \qquad A2 = \frac{(1+i)^m - 1}{(1+i)^n - 1} * \frac{(1+i)^n - (1+e)^n}{(1+i)^m - (1+e)^m} * A1$$

So the levelized value of capacity is only adjusted for the difference between the length of the contract and the life of the alternative investment.

As shown in the examples below, the adjustment for adding capacity sooner than is needed is much larger (i.e. decreases the capacity payment) than the adjustment for contract lengths that differ from the lifetime of alternative capacity additions.

Example 1:

Assuming that the levelized annual value of a capacity purchase at the time of need (A1) is $1/kW and:

m = 33 years
n = 20 years
i = 11.5%
e = 4%
a = 7 years

Then:

$$A2 = \frac{(1.115)^{33} - 1}{} * \frac{(1.115)^{13} - (1.04)^{13}}{} = 0.339$$

$$(1.115)^{20} - 1 \qquad (1.115)^{33} - (1.04)^{33}$$

Therefore, the appropriate annual capacity value of a contract that is 20 years long compared to 33 years of the alternative capacity addition, and starts seven years before the need for capacity, is about 34% of the annual capacity value of the longer-term capacity determined at the time of need.

However, if the capacity is added when it is needed (rather than prior to that time), the payment is much closer to the annual capacity value of the longer-term capacity determined at the time of need. The following example illustrates this point by using the same difference in length of contract as in Example 1, but assuming that the capacity is added when needed.

<u>Example 2:</u>

Assuming that the levelized annual value of a capacity purchase at the time of need (A1) is $1 / kW and:

m = 33 years
n = 20 years
i = 11.5%
e = 4%
a = 0 years

Then:

$$A2 = \frac{(1.115)^{33} - 1}{(1.115)^{20} - 1} * \frac{(1.115)^{20} - (1.04)^{20}}{(1.115)^{33} - (1.04)^{33}} = 0.916$$

The appropriate annual capacity value of a contract that is 20 years long compared to 33 years of the alternative capacity addition, and starts when the capacity is needed, is about 92% of the annual capacity value of the longer-term capacity at the time of need.

The adjustment for the length of the contract is not as great, as indicated in example 3, which uses an extreme case of a 1-year contract and assumes that the capacity is added when needed.

<u>Example 3:</u>

Assuming that the levelized annual value of a capacity purchase at the time of need (A1) is $1 / kW and:

m = 33 years
n = 1 year
i = 11.5%
e = 4%
a = 0 years

Then:

$$A2 = \frac{(1.115)^{33} - 1}{(1.115)^{1} - 1} * \frac{(1.115)^{1} - (1.04)^{1}}{(1.115)^{33} - (1.04)^{33}} = 0.705$$

That is, the appropriate annual capacity value of a contract that is only 1 year long compared to 33 years of the alternative capacity addition, and starts when the capacity is needed, is about 71% of the annual capacity value of the longer-term capacity at the time of need.

December 20, 2002

TO: **Distributed Generation Rates Workgroup**

FROM: **CenterPoint Energy Minnegasco**
Hennepin County
Institute for Local Self Reliance
Izaak Walton League of America, Midwest Office
Korridor Capital Investments, LLC
Prairie Gen
The Minnesota Project

RE: **Comments requested on: Present proposals for agreement regarding standby services.**
Docket E999/CI-01-1023

In response to the December 11, 2002 meeting of the Distributed Generation (DG) Rate Workgroup, we jointly submit the following comments on the requested agenda item:

It is widely recognized that standby charges will continue to represent a decision factor for customers who are considering DG installations. These charges, particularly the reservation fees, dramatically impact DG economics and are a major barrier to DG development. The group agrees with the argument that reservation charges should reflect that a portion of the system is being held available to provide this service. However, these charges should reflect the true costs associated with the service.

Currently, the DG Rate Work Group is progressing in the notion that the existing standby charges in the electric utilities' tariffs are the fair reflection of the fixed costs. It may not be prudent to argue on the validity or the nature of these costs given the limited timeline of the current docket proceedings. Perhaps, a separate discussion or proceedings would be needed. Therefore, our discussion is focused on the credits for the DG customer to compensate against these standby reservation costs. In order to assign the pertinent credits applicable to the standby-related charges, the reservation fee costs structure has to be itemized under each electric utility's tariff.

Before we address the applicable credit requirements, the following three items needs some attention:

1) The standby service riders under each electric utility tariff should be applicable to any non-residential customer who requires over 100 kW of standby capacity. Therefore, Xcel's current standby tariff should revert to 100 kW instead of 40 kW.

2) Utility disturbances that knock a DG off line (i.e. voltage transients) should not be used as a reason to invoke standby rates or to count against the three allowed occurrences before the amount of standby is restated.

3) If an existing customer installs DG and elects zero standby capacity, an unauthorized use penalty shall be applied rather than (arbitrary) equipment removal as a means of

"penalizing" the system additions. To the extent there are potentially, hazardous system consequences to DG voltage and system stability, a study should be done at the distribution operators cost, and submitted to the DG for discussion and review, prior to any changes occurring. Notice of the removal and equipment consequences shall be provided in writing no less than 90 days prior to equipment removal.

Credit Requirements:

In the Menu of Services from DG Customer to Utility[1], the sub-group proposed and defined the credits pertinent to the DG customer. The reservation fees costs structure has to be itemized under each electric utility's tariff to actually reflect the pertinent credit. We propose that all credits are proportionate to the explicit value within a given utilities' tariff.

A. Generation Credit (capacity only):

We will use the Xcel's Reservation Fee of $3.15/kW/month for the template. The breakdown of the numbers is an assumption based on previous discussions in our Working Group meetings.

Generation component of the Xcel tariff:	$.68
100% Credit requirement for accreditable capacity provided:	$.68

B. Transmission credit:

Credit for a path not required.

Transmission component of the $3.15:	$.44
100% Credit requirement:	$.44

DG eliminates the actual flows by sourcing transmission AT the load within the distribution system.

C. Distribution credit:

Distribution should be viewed as two distinct parts, D1 (Bulk Distribution) and D2 (Local Distribution).

Distribution Component of the $3.15 is assumed:	$2.03

We are assuming 40% allocation of these charges to the bulk (D1) distribution, and 60% to the local (D2) distribution charges.

Bulk (D1) Distribution Component:	$0.82 (40% of $2.03)
50% D1 Credit requirement:	$0.41

Local (D1) Distribution Component:	$1.21 (60% of $2.03)
As described below:	

[1] Menu of Services From DG Customers, submitted to the DG Rate Work Group on October 29, 2002.

The concept tiered "Locational DG Distribution Credit" to be established for the DG Tariff. It would require the utility to segregate its service territory into 3 DG territories based on capacity constraints and/or costs for system upgrades:

1) "Red" - a very large benefit from DG installation [very constrained areas with high upgrade costs, which may be about 5-10% of its territory];

2) "Yellow" - a moderate benefit from DG installation [moderately constrained areas, maybe 15-20% of territory]; and

3) "Green" - a general benefit [the rest of the service area].

The PUC would determine the credit rate within each of these areas, based on the avoided distribution system upgrade costs that the utility avoids or defers because the DG has been installed in that location. The DG customer and utility share these costs.

D. Line loss credit:

DG relieves utilities of having to supply the additional generation capacity associated with line losses to serve the DG customer.

All percentages losses designated under Generation, Transmission, and Distribution by the electric utility shall be credited.

E. Diversity credit for generation, transmission, and distribution:

Utilities should give diversity credit in backup generation allocation better than 15% because small DG's require less reserve on a diversified basis than bigger units when applying the standard simulation process used by utilities. This method uses 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. Therefore, 8% is a reasonable estimate at this time as an appropriate reserve.

A diversity factor should be applied to bulk distribution system when allocating DG customer distribution even though service drop and local transformer must be sized to full load of customer without DG in operation. An option would be a big bulk distribution credit.

Other Credits:

Although the above credits can be directly implied against the reservation fee, we believe that credits (either offsetting standby rates or increasing the buyback rates) should be given to DG projects that are providing physical assurance, renewable, or meet certain thresholds of operational efficiency (e.g. high-efficiency cogeneration systems).

1. Physical Assurance Credit:

If a customer is willing to provide physical assurance to the utility, that customer should not have to pay for any facilities or peak demand related costs associated with distribution service and should have the ability to opt out of standby services entirely or elect to take maintenance or interruptible services.

2. Renewable Credits:

For DG renewable energy technologies, one option would be to provide renewable DG projects a credit for supplying power for utilities' mandatory green pricing programs. These programs allow utility customers to pay a premium on top of their electric rates for renewable energy.

State law allows utilities to use DG projects to meet utility green pricing program obligations. DG projects should be given the full amount of the current green pricing tariff of the particular green pricing program of the utility being interconnected to (less some administrative/marketing costs, which we believe is typically less than 10 percent). So for example, if a renewable DG interconnects with Xcel Energy's system, and their green pricing adder is 2.4 cents/kWh, the DG should get slightly less than 2.4 cents/kWh as a credit.

Another possible green credit scenario would be to allow a renewable DG customer to have the option of keeping their "green tags" for their project or selling them to the utility for a set amount, say 0.75 cents/kWh.

A third option, the PUC also requires the use of environmental externality values in certain situations for evaluating future power supplies. There may be some methodology to calculate an environmental externality credit for DG based on the adopted values or market prices for certain pollutants. This option would be less preferable due to the relatively low externality value for CO_2 emissions.

3. Operational Efficiency Credits:

State law clearly has a preference for maximizing the efficient use of electrical energy including maximizing the efficiency of the production of electricity. These laws included energy conservation programs, building energy codes, tax breaks for high-efficiency products to name just a few. State law also provides a sliding-scale property tax system for high-efficiency cogeneration. The more efficient the cogeneration system is the lower your property tax bill.

The DG statute was put in place to "promote" clean and efficient sources of distributed electrical generation. The letter of the DG law can be met by providing an efficiency credit to high-efficient cogeneration. This credit would recognize the valuable environmental aspects of cogeneration for offsetting emissions and by utilizing what would otherwise be wasted energy.

January 17, 2003

TO: **Distributed Generation Rates Workgroup**

FROM: **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

RE: **Comments requested on: DG Customers proposal on Credits**
Docket E999/CI-01-1023

In response to the January 8, 2003 meeting of the Distributed Generation (DG) Rate Workgroup, we jointly submit the following comments on the requested agenda item:

The discussion in the last DG Rates Workgroup was centered on defining credits pertinent to the physical assurance of load reduction. The amount of credits was defined to offset charges against the monthly standby reservation fees if a DG customer elected physical assurance on a portion or its entire load. For the DG customer electing physical assurance option of existing load, the generation and transmission reservation charges were defined to be zero. However, the customer is expected to pay the monthly distribution charges portion in the reservation fee or pay it out as one-time *distribution stranded costs* to avoid monthly standby distribution charges.

Before the DG Rates Workgroup proceeds to address other pertinent DG credits, we believe further clarification is needed in the physical assurance credits discussion particularly related to distribution charges:

1. The entire distribution charges portion in the standby reservation fee should not be considered as the total stranded distribution costs. The distribution charges should be itemized under the electric utilities tariffs to reflect the true cost allocation as the bulk or

local distribution charges. A DG customer should only pay for the stranded distribution costs related to the local distribution charges since the bulk distribution assets would become available to serve other loads.

2. The stranded distribution costs should be based on the current book value of the localized distribution 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. To the extent the electric utility benefits by reselling that portion of the distribution of the system, a credit, as a reimbursement of payments, should be given back to the DG customer.

3. The standby charges, including the entire distribution portion, should be zero if a customer elected physical assurance on a new DG load (i.e. green-field or capacity addition).

4. Physical assurance should be based on the *customer elected generation capacity*. A DG customer should have an option to elect the entire or portion of its DG load. For example, a 5 MW peak load customer with a 2 MW DG system should be able to elect physical assurance between 0 to 2 MW.

5. Under physical assurance option, the customer's load from the grid must not exceed the required peak capacity. This can be done by capping the subscribed demand under the applicable tariff. For example, a 5 MW customer elected 1 MW as a physical assurance, the required peak load, or a load on the utility meter, must not exceed 4 MW regardless of whether the DG unit is being utilized at that given moment.

6. A DG customer should have a flexibility to elect physical assurance with the firm or non-firm standby services on partial DG loads as needed.

- In the non-firm standby by category, we believe it may be necessary to pay D2 (local distribution), but we believe D1 (bulk distribution) should be zero just as it is for Transmission.

The table on the next page summarizes our recommendation on how the physical assurance, firm, and non-firm standby services can be categorized as part of the reservation fees requirements.

Table I

Reservation Fees Categories	Physical Assurance	Firm Standby	Non-firm Standby
Generation	0	G	0
Transmission	0	T	0
Distribution: D1– Bulk Distribution D2– Local Distribution	 **0** **D2 (stranded costs)**	 D1 D2	 **0** D2

The net offset in all generation, transmission, and distribution (both D1 & D2) categories can be allocated as the Workgroup addresses value for other credits. The following outline summarizes our discussion and recommendation pertinent to other credits.

We have already outlined the definition of other pertinent credits in previous documents submitted to the DG Rate Workgroup. Please refer to: the Part II section in the 'combined' Menu of Services document dated December 19, 2002, the DG Customer Comments on Standby Service document dated December 20, 2002, and Comments on Green Credits for Distribution Generation document dated January 8, 2003.

In this document, we will attempt to define 'how' these credits can be applied.

1. Distribution Constrained Credit:

The concept of tiered "DG Distribution Constrained Credit" should be established for the DG Tariff. It would require the utility to segregate its service territory into 3 DG territories (red, yellow, and green) based on capacity constraints and/or costs for system upgrades.

The distribution constrained credit should be applicable to both Bulk (D1) and local (D2) distribution. The credit should be available to all DG customers regardless of selecting the services under the firm standby, non-firm standby, or physical assurance options.

The distribution constrained credit should be valued on how the DG mitigates utility investment. The credit could be a short-term payment until the utility upgrades the distribution zone, or a long-term payment if it completely offsets utility investment. The three DG territories' designated maps should be available to any DG customer considering DG installations, and it should be updated on an annual basis. A similar transmission constrained credit should be applied if the DG provides benefit to the transmission grid.

2. Diversity Credit:

We assume that standby charges and the components that make them up are consistent across the Minnesota electric utilities. For example, all utilities' standby charges related to generation should only reflect reserve margins as designated by MAPP, and should not reflect utilities' total generation costs. If standby charges in any current Minnesota electric utilities tariffs do not reflect this type of diversity, these charges should be reevaluated prior to setting DG rates.

MISO is typically requiring member utilities to maintain reserve margins in the range of 15%-18% based on loss of load probability studies. As a result, utilities are proposing to use this same factor in determining the amount of generation needed to back up DG's. For example, the utility must install or acquire 15-18 MW of generation to back up 100 MW of DG capacity.

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% reserves 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.

3. Line Loss Credits:

DG relieves utilities of transmission and distribution losses otherwise necessary to serve an equivalent amount of new customer or existing customer load. The following method based on calculating the demand and energy losses can apply as a credit:

a. Demand losses calculated on the basis of the capacity value of generation times the demand loss factor. For example, 3% for transmission loss times the DG size in kW times the capacity value ($/kW) of generation.

b. Energy losses calculated on the basis of the off-peak and on-peak value of the energy (kWh) otherwise delivered. For example, 3% for transmission times the

DG size times the hours operated in each period (peak and off-peak) times the generation value (fuel and O&M) of the energy.

In addition to the foregoing, the actual capital cost avoidance for releasing capacity can be measured by the tariff for transmission or distribution. For example, the firm transmission in MISO is approximately $1.25 per kW per month. It can be multiply by the DG rating to obtain tariff savings.

4. Renewable Credits:

We support the idea that there should be a credit for renewable DG projects. Customers should be allowed to opt out of this credit if they so choose. The “greenness” of the electricity is a non-power attribute that has a potential future market and can be separated from the energy and capacity of the DG project. If the DG customer can find a better market for this non-power attribute, they should be allowed to do so.

We support the idea that renewable DG projects should be given a credit if the utility is selling more electricity through their green pricing program than renewable DG projects are producing on their system. The credit in this case should be whatever the premium is of the green pricing program less some administrative/overhead component. So if a utility's green premium is $0.025 per kWh, the renewable DG owner should get that amount per kWh less a justified administrative offset.

If the DG customer is taking credit for supplying power to the green pricing program, the utility would also be entitled to the green tags (attributes) for the electricity supplied by the DG project.

A utility that has more renewable DG on its system than it needs for its green pricing programs should be required to pay for the renewable DG's green attributes if the DG would like to sell them. Since Minnesota does not have a renewable energy credits trading system, we are not able to assign a marketplace value to the green attributes. Until such a trading system is in place, the green pricing premiums that utilities charge are a way to assign a value to renewable energy DG projects. Once the utility pays for the DG project's green attributes, the utility can apply that amount of renewable energy toward the legislative directive to make a 'good faith effort' to generate 10 percent of their electricity from renewable energy.

5. Emission Credits:

We support the idea that DG projects should be eligible to receive a credit for their impact in lowering utility system emissions. The Public Utilities Commission has set environmental externalities values for six pollutants (PM, SO2, NOx, CO2, PB, CO), which are indexed for inflation. We suggest that these values be used as a basis for calculating the emission credit. In the case of NOx and SO2, market rates could be used in place of the externalities values. Markets do not appear to materialize for the other pollutants.

Since a DG project will displace a mix of electricity sources and not electricity generated by a particular plant on a utility's system, a credit can be designed by comparing the emissions from the DG project to the average emissions per kWh of a given utility's system.

If a renewable energy project seeks an emissions credit it should not also be eligible for the green credit. And the renewable energy DG project should have the right to keep the green attributes or "green tags" associated with the project. Unless the utility pays the renewable DG for the green attributes, those attributes should stay with the owner of the DG project.

6. Operational Efficiency Credits:

We conclude 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. This could be done by converting the Btus of thermal energy into kWh. This will ensure that CHP projects with the highest efficiency levels will receive the largest credit.

7. Reliability Credits:

The reliability credit should be given on the basis of the DG system availability during utility’s critical peak time. As part of the peak interruptible tariff, electric utility provides tiered controllable demand (kW) discounts to the peak interruptible customers on the basis of their performance factors (PF) where the higher performance factor customers attain more discounted controllable demand charges. Since the DG system operates continuously, it has a higher system reliability or performance factor. Comparatively, some DG facilities may have a higher performance factor than other DG facilities.

The current firm standby charges do not differentiate the system availability or performance factor within the DG class of customers. We recommend a similar tier approach should be established to discount the firm standby charges on the basis of DG reliability. Thus, the reliable DG systems should get discounted standby charges.

Conclusion:

Based on our preceding comments, the following table is an attempt to assign how credits can be applied towards the generation, transmission, and distribution. The net offset against the standby reservation fee could be positive or negative depending on how these credits benefit the grid.

Table II

Credits applied	Generation	Transmission	Distribution (D1 and D2)
- Distribution constrained credit:	-	-	Yes
- Transmission constrained credit:	-	Yes	-
- Diversity credit:	Yes	Yes	Yes
- Line Loss credit:	-	Yes	Yes
- Reliability credit:	Yes	Yes	Yes
- Renewable credit:	Yes	-	-
- Emission credit:	Yes	-	-
- Operational efficiency credit:	Yes	-	-

M E M O R A N D U M

TO: Distributed Generation Rate Work Group

FROM: Alliant Energy
Dakota Electric
Minnesota Power
Otter Tail Power
Xcel Energy

DATE: January 20, 2003

SUBJECT: Comments on Issues Raised in January 10, 2003 e-mail from DOC

Following are brief consolidated comments of Alliant Energy, Dakota Electric, Minnesota Power, Otter Tail Power and Xcel Energy regarding issues raised in the January 10, 2003 e-mail from Kate O'Connell at the Department of Commerce.

Locational DG Distribution Credit

Issue

It has been suggested that the concept of a tiered "Locational DG Distribution Credit" be established for the DG tariff. Implementing this concept would require each utility to segregate its service territory into three DG territories based on capacity constraints and/or costs for system upgrades including the following:

1. "Red" -- A very large benefits from DG installation.
2. "Yellow" -- A moderate benefit from DG installation.
3. "Green" -- A general benefit from DG installation.

The PUC would determine the credit rate within each of these areas based on the distribution system upgrade costs that the utility avoids or defers because the DG has been installed in that location.

Response

While the concept of a tiered locational DG distribution credit acknowledges that the benefit from installing DG will vary depending on local circumstances, identifying, segregating and updating electric utility service territory into these three tiers would be extremely difficult to accomplish from both an engineering and administrative perspective. In addition, this concept generally does not follow current rate-making theory as utility rates do not change based on the location of the customer. Also, there may be situations where distribution benefits do not exist and distributed generation may cause additional costs and safety concerns.

However, as we have stated many times in previous comments, we believe the identification of distribution benefits is an important element in providing credits to potential DG customers. Since the circumstances of each DG installation can be unique, we suggest that a better way to identify the potential distribution credits/costs is to incorporate this analysis in the up-front system study required for each DG installation. Evaluating potential distribution credits/costs at this point should not significantly delay the study and review process at the beginning of such projects and, more importantly, will result in more accurate accounting of site-specific credits/costs for each installation.

Line Loss Credit

Issue
It has been suggested that DG relieves utilities of having to supply the additional generation capacity associated with line losses to serve the DG customer. Accordingly, it has been suggested that all percentage losses designated under generation, transmission, and distribution by the electric utility be credited.

Response
The development of costs for generation, transmission and distribution service inherently reflects the impact of line losses. Accordingly, the generation and transmission credits discussed by the Work Group at the January 8, 2003 meeting already incorporate the benefit of reduced line loss. However, there may be specific circumstances where the location and operation of a DG facility could provide additional generation and transmission line loss benefits. Accordingly, we recommend that the identification and quantification of such additional line loss credits be included in the up-front study as we proposed above for identifying Locational DG Distribution Credits.

Diversity Credit

Issue
It has been suggested that utilities give a diversity credit for DG installations that recognizes a reduced reserve margin because small DGs require lower reserves on a diversified basis than larger utility generating units.

Response
The amount of reserve margin each member has to carry is set by MAPP, not by the utility. MAPP develops the reserve margin level based on reserve margin studies of the generation in place and the contingencies the region wants to protect for. As the generation mix changes because of the development of small distributed generation, 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, the determination of reserve margin levels needed 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 Credits

Issue

It has been suggested that additional credits be provided to renewable DG installations. Suggested options for determining these credits include:

1. Externality -- based credit.
2. Market -- based credit.
3. Hybrid of market and externality methods.
4. Green tags credit.
5. Green -- pricing charge.

Response

Renewable DG projects will already receive a benefit of the externality -- based concept in that renewable DG projects will be evaluated within the context of the avoided externality benefits as identified by the MPUC.[1] This evaluation, including the price paid by the utility, will occur through the IRP Process. Although DG customers do not need to go through the IRP process, they will still benefit from the avoided cost setting part of the IRP. Therefore, the delivered price of a renewable DG project may be higher than other alternatives and yet be selected as the next resource after consideration of such externality benefits.

Also, for energy the DG uses internally to offset load, the value they receive is in avoiding paying the retail rate for their power supply needs. As the IRP process brings higher cost renewable power into the utility's resource mix, the retail rate will rise and the value the DG received from avoiding paying that rate will rise. Therefore, the DG will directly receive the benefit for renewables (even if the DG isn't renewable) from the MPUC approved IRP treatment of renewable value.

The proposal for market--based credits, hybrid of market and externality methods, and green tag credits have no bearing on existing avoided costs and as such should not be applied as a credit method.

Furthermore, the suggestion that renewable DG should receive a payment based on the premium price adder reflected in retail rates 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, this price adder reflects the higher costs of securing and delivering renewable energy to meet customer load requirements instead of more conventional generating resources.

Finally, any credits that are developed by this rate group should be cost-based and should only be applied if there are measurable benefits to the utility. Any other credits that relate to societal benefits are outside the scope of this rate group as they must be driven by legislative policy.

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[1] Externality benefits are used in resource planning analysis for the purpose of selecting a proposed plan for MPUC approval. No actual externality costs are collected or paid.

Operational Efficiency Credits

Issue

It has been suggested that operational efficiency credits be provided to DG units that recognize that these units provide electric energy at lower thermal requirement than conventional generating units.

Response

To the extent that any distributed generation unit can operate at higher efficiency levels than conventional generation resources means that such DG facilities will have lower operating costs than conventional generating units. Assuming that wholesale energy is bought and sold in a competitive market, such DG installations will naturally receive higher earnings than those from conventional generating resources. Offering an additional operational efficiency credit is not necessary.

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