Direct Testimony and Schedules
Michael A. Peppin

Before the South Dakota Public Utilities Commission of
The State of South Dakota

In the Matter of the Application of
Northern States Power Company, a Minnesota Corporation

For Authority to Increase Rates for
Electric Utility Service in South Dakota

Docket No. EL09-___
Exhibit___(MAP-1)

Class Cost of Service Analysis
and
Selected Rate Design

June 30, 2009

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael A. Peppin. My business address is 414 Nicollet Mall, 7th Floor, Minneapolis, Minnesota, 55401.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Xcel Energy Services Inc., which is the service company subsidiary of Xcel Energy Inc. My title is Principal Pricing Analyst.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am providing testimony on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), operating in South Dakota.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. A statement of my qualifications and experience is provided in Exhibit____(MAP-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present the Company's proposed class cost of service study ("CCOSS"), and selected portions of the Company's proposed rate design. Mr. Steven Huso will present the Company's rate design objectives and the majority of the Company's proposed rate design changes.

With respect to the CCOSS, the Company has provided two versions. The first version is the one proposed by the Company for use as the guide to designing rates and is described in more detail below. Its presentation format has been revised from that used in the past, eliminating a number of subgroups within the classes and instead providing information for the four major classes of service; Residential, Small Commercial Non-Demand, Commercial & Industrial ("C&I") Demand and Street Lighting.

The second version is provided for reference proposes. It is essentially the same as the first version except that it divides the Demand-Billed C&I class into two subgroups, small (less than 1.0 MW) and large (1.0 MW or greater).

Q. PLEASE LIST EACH OF THE COST OF SERVICE AND RATE DESIGN TOPICS YOU ADDRESS IN YOUR TESTIMONY.

A. The topics I address are as follows:

- Class Cost of Service Studies
  - Proposed Version
  - Comparison Version
- Selected Rate Design Revisions
  - Voltage Discounts
  - Distributed Generation Interconnection Procedures
  - General Rules and Regulations

Q. WHAT EXHIBIT AND SCHEDULES ARE YOU SPONSORING IN THIS FILING?

A. I'm sponsoring Exhibit____(MAP-1), which contains the following Schedules:

Schedule 1, Statement of Qualifications and Experience

Schedule 2, <u>Proposed</u> Class Cost of Service Study Summary Results

Schedule 3, Guide to Embedded Class Cost of Service Study

Schedule 4, Comparison Class Cost of Service Study Summary Results
Schedule 5, Comparison Class Cost of Service Study Detailed Results
Schedule 6, Voltage Discount Cost Analysis
Schedule 7, Distributed Generation Interconnection Manual
Schedule 8, General Rules & Regulations – Cost Analysis

I also sponsor Exhibit___(NSP-1), Statement O in Volume 1 of the Application, Proposed Class Cost of Service Study detail results.

II. CLASS COST OF SERVICE STUDIES

A. The Proposed Class Cost of Service Study

Q. PLEASE INTRODUCE THE CCOSS THE COMPANY PROPOSES USING IN THIS RATE CASE.

A. The Company has prepared a CCOSS, with a summary of the results shown on Exhibit___(MAP-1), Schedule 2. Please See Exhibit___(NSP-1), Statement O in Volume 1 for the detailed CCOSS results.

Q. HAS MARGINAL COST INFORMATION BEEN USED IN THE COMPANY'S CCOSS IN THIS CASE.

A. Yes, there are two significant applications of marginal costing concepts in the Company's CCOSS. The two applications are the "stratification" of fixed production costs and the development of the Company's "E8760" energy cost allocator.

Q. EXPLAIN WHAT "STRATIFICATION" OF FIXED PRODUCTION COSTS MEANS AND HOW IT REFLECTS MARGINAL-COSTING CONCEPTS IN THE CCOSS.

A. Stratification is a reference to the technique the Company uses to separate ("stratify") fixed production costs into "capacity-related" and "energy-related" portions. The capacity-related portion includes all the fixed costs of peaking plants but also a "peaking-plant-equivalent" portion of the base-load plant costs. This "peaking-plant-equivalent" portion of base-load plant costs is based on the remaining costs of each plant (original costs less depreciation) and varies from 19% to 33% of the total fixed costs of our base-load plants.

After fixed generation costs are stratified, the capacity-related portion is allocated using a traditional system demand ("D10C") factor. But the "energy-related" portion is allocated using the E8760 energy allocator. This stratification and allocation process is "marginal-cost-based" because the resulting class-cost-responsibilities and the corresponding rates developed from these costs are comparable to those that would result from a marginal-cost-based study.

Q. HOW ARE MARGINAL-COSTING CONCEPTS REFLECTED IN THE E8760 AND ITS APPLICATION TO ENERGY-RELATED COSTS?

A. The E8760 energy allocator is based on the system's marginal energy cost pattern and each class's time-varying load pattern for each of the 8760 hours of a year (note that in 2008 there were 8,784 hours in the year and the 2008 data was used to create the energy allocator used in the CCOSS). Its application to the "energy-related" fixed productions costs, as well as the fuel and purchased energy costs, produces class cost responsibilities (and resulting energy charges) that are comparable to those that would result from a marginal-cost-based study.

Q. ARE THERE DIFFERENCES BETWEEN THIS CCOSS AND THE CCOSS THE COMPANY FILED IN ITS LAST GENERAL RATE CASE?

A. The CCOSS filed with this case is essentially the same as that approved by the Commission in the previous case but it incorporates updates and refinements in the following areas:

- Subgroup Consolidation
- Interruptible Capacity-Cost Accounting
- Energy Cost Allocation
- Seasonal Split of Generation Capacity Costs
- Secondary Distribution Cost Allocation
- Secondary Service Cost Allocation
- General Plant Allocation

Subgroup Consolidation

Q. PLEASE EXPLAIN WHY THE COMPANY IS CONSOLIDATING CERTAIN SUBGROUPS OF CUSTOMER CLASSES IN THE PROPOSED CCOSS.

A. Historically, the Company's CCOSS included a number of "subgroup" categories within the classes of service. The substantial additional complexity and detail associated with these several subgroups is not useful in developing the basic class cost responsibility so the Company has simplified the CCOSS in the first version by consolidating the subgroups into their respective primary classes of service. In the second version, the below described subgroups have been retained for comparison purposes.

The Company's rate structure has been, and continues to be developed around four primary cost of service classes. They are Residential, Small Commercial Non-Demand, C&I Demand and Street Lighting. Within the C&I Demand class, where there are service-voltage options, the distribution-system cost differences are accounted for in the design through rate discounts for customers served at primary or higher voltages. These service-voltages options are secondary, primary (which includes transmission transformed service), and transmission. In South Dakota there are no customers that currently receive service at transmission transformed or transmission voltage.

Q. PLEASE DESCRIBE THE SPECIFIC SUBGROUP CONSOLIDATIONS THAT HAVE BEEN MADE.

A. The Residential class is a consolidation of the former "With" and "Without" space-heating subgroups, as well as the specialized Residential "Load Management" rates. The Commercial Non-Demand class remains the same except it includes the Fire and Civil Defense Siren Service. The C&I Demand class is a consolidation of the "Small" and "Large" as well as the "Firm" and "Interruptible" subgroups. Finally, Street & Area Lighting, which had been made up of three subclasses (Leased, Purchased and Automatic Protective Lighting), has been consolidated into one class

<u>Interruptible Capacity-Cost-Accounting</u>

Q. WHAT CHANGE WAS MADE REGARDING INTERRUPTIBLE CAPACITY-COST-ACCOUNTING?

A. In order to describe the accounting change, I will use the term "adjusted" to describe the change and the term "unadjusted" to describe the cost responsibilities that were historically used as the indicators of class cost responsibilities.

Unadjusted costs include the discounts received by interruptible customers within the respective customer classes that receive them. However, as the size of the Company's interruptible programs grew it became clear that these traditional unadjusted cost responsibilities did not properly account for the fact that interruptible rate discounts are really the "cost" of this particular source of generation peaking capacity. Therefore, the Company modified the CCOSS to produce what we call <u>adjusted</u> cost responsibilities in order to appropriately account for this growing source of peaking capacity. Doing so is appropriate because interruptible rate discounts (lost revenues) are a real cost to all customers arising from this alternative source of generation peaking capacity.

Q. IS THIS CHANGE CONSISTENT WITH HOW THIS SERVICE IS PROVIDED?

A. Yes, it is. The economic essence of a utility's "obligation to serve" is to provide low-cost reliable <u>firm</u> service. The "interruptible service" is in reality firm service with an after-the-fact contract provision through which the utility has the option to buy back (from willing customers) all or part of their "regulatory entitlement" to firm service. The resulting capacity purchase transactions occur when, and if, doing so is a cost-effective source of peaking capacity. This means the "interruptible rate discounts" are really power supply costs, and should be recognized as such in the CCOSS.

Q. HOW WAS THIS CHANGE REFLECTED IN THE CCOSS?

A. To accomplish the change in interruptible capacity-cost-accounting, the Company has added three lines to the CCOSS format as shown on Exhibit___(MAP-1), Schedule 2. The first is line 8, labeled "Interruption Rate Discounts." It shows the difference between the firm and interruptible rates, which identifies the amount of the discounts and the classes from which they originate. The second is Line 9, labeled "Interruptible Capacity Cost," which shows how this interruptible-capacity cost is allocated to the classes, using the applicable generation capacity cost allocation factor. Finally, subtracting Line 8 (Interruption Rate Discounts) from Line 9 (Interruption Capacity Costs) is the resulting shift in Revenue Requirements caused by this change in interruptible capacity-cost-accounting as shown on line 10. These additional CCOSS lines are also shown on page 2, lines 6-8 of Statement O (located in Volume 1 of the Application) and Exhibit___(MAP-1), Schedule 5.

Energy Cost Allocation

Q. PLEASE DESCRIBE THE CHANGE IN THE ENERGY COST ALLOCATION.

A. The energy cost allocator used in this CCOSS is conceptually the same as has been used in previous cases but has been refined to more precisely reflect class cost responsibilities.

The energy allocator from the Company's previous studies (referred to as "E20") was based on the system on- and off-peak marginal energy cost ratio as well as the class on- and off-peak use percentages. It was calculated using the time-variant data then available, which was a simple two-period (on- and off-peak) cost determined using marginal cost and class use data. Now, however, we have more detailed marginal cost data for the system and corresponding load pattern data by class. We also have better computer capabilities, so it is now practical to develop a similar allocator but one that makes use of data from all 8,760 hours of a year as compared to the previous two-period method. The result is a more precise version of the previous "E20" allocator, which has been labeled "E8760."

Seasonal Split of Generation Capacity Costs

Q. PLEASE EXPLAIN WHAT GENERATION CAPACITY COSTS ARE, AND DESCRIBE HOW THEY HAVE BEEN SEASONALIZED?

A. As in previous CCOSSs, the fixed generation costs have been "stratified" into "capacity-related" and "energy-related" portions. The capacity-related portion is then "split" into summer and winter components and allocated to the classes based on their respective contributions to the system's seasonal-peak loads.

In the Company's last CCOSS this seasonal split was based on a ratio of summer-to-winter system loads and was calculated as follows. The twelve monthly system loads were grouped into the four-month summer season and the eight-month winter season. Then the lowest of the twelve monthly peak loads was subtracted from each of the monthly loads. The average of these adjusted monthly loads, for each season, were used to develop the seasonal load ratio, which is used to "split" the capacity-related portion to the seasons.

Applying that method in this case, would result in a heavier summer weighting than occurred in the previous rate case. For this case, that method would yield a summer-to-winter ratio of more than 3.5 to 1.0. That means 78% of capacity costs would be assigned to the four-month summer season and just 22% assigned to the eight-month winter season. We consider 22% to be unreasonably low because an analysis of peaking plant operating hours shows significant operating hours in non-summer months.

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO ADDRESS SEASONAL COST ALLOCATION IN THIS CASE?

A. The choice of an appropriate method for allocating costs to seasons is perhaps more problematic than other cost allocation questions, which are already difficult. The challenge of this seasonal cost allocation issue is to isolate the portion of monthly system loads that determines the capacity portion of fixed generation costs. We then develop from that data the system's seasonal pattern and finally, calculate the class contributions to the seasonal pattern.

Because the method used in the last rate case would assign an inappropriately low 22% of the costs to winter peaks, the Company is proposing a refinement to the method, which mitigates the problem. The Company is proposing to subtract the average annual load (rather than the previously used minimum monthly load) from each of the system's twelve monthly peaks. Using the average annual load is consistent with the Company's "stratification" process, which is the basis for identifying the "capacity-related" portion of fixed production costs. This refined method yields a smaller ratio of about 3.00 to 1.00, which means approximately 75% of peaking capacity cost is assigned to the summer season instead of 78%.

Secondary Distribution Cost Allocation

Q. PLEASE EXPLAIN WHY YOU MADE A CHANGE TO THE ALLOCATOR APPLIED TO SECONDARY DISTRIBUTION COSTS?

A. In the Company's previous cost studies, all distribution costs were allocated based on individual class shares of the total of all class peak loads (as distinguished from system peak loads). The use of class peak loads for allocating distribution costs is very common and is generally considered appropriate for distribution system cost allocation, especially the costs of substations and primary distribution facilities. The substations and primary facilities are at the "up-stream" end of the distribution system where their size (and corresponding cost) is driven by the total load of the classes (i.e. sum of class peaks).

However, the appropriateness of this allocator for allocating secondary transformers and secondary distribution lines is not as clear as it is for the substations and primary facilities. Secondary facilities are at the "down-stream" end of the system closer to the customer, where their size and cost become driven by individual customer peak loads (sometimes referred to as non-coincident peaks), as well as by the class peak loads.

Therefore, the Company is using a modified allocator for secondary lines and secondary transformers. This modified allocator is a 50% weighting of the <u>class</u> peak allocator and a 50% weighting of a <u>customer</u> peak allocator. The customer peak allocation for a class is the sum of the individual customer peak loads (billing demands) from that class, relative to the sum of customer peak loads for all the classes.

Secondary Service Line Cost Allocation

Q. DESCRIBE THE PROPOSED CHANGE IN THE SECONDARY SERVICE LINE ALLOCATOR.

A. This service line cost allocation modification is a direct extension of the modification of the secondary distribution cost allocation discussed above. The traditional class peak allocator has also been used historically to allocate the "capacity" portion (not the "customer" portion) of service line costs. A service line is the conductor that extends from the secondary transformer (or in some cases secondary distribution line) to the customer's meter. For these service line facilities, it is clear that the individual customer peak load determines its size and associated cost. Therefore, in this cost study, the Company is proposing to allocate the capacity cost portion of customer service line facilities based solely on the customer peak allocator described above.

General Plant Allocation

Q. PLEASE EXPLAIN THE REASON FOR THE CHANGES IN THE ALLOCATION OF GENERAL PLANT.

A. Recent changes in the Company's accounting system require a minor modification in the way General Plant is allocated. General Plant refers to plant investment related to the electric utility but which may be associated with more than one of the service functions of production, transmission, and distribution. In the past, the two General Plant subcomponents, System and Local, were allocated differently. The System and Local subcomponents were used to identify whether the asset served the entire electric (and gas) system(s) or just local needs.

The Company's accounting system no longer distinguishes between System and Local, and as a result, the allocation of General Plant will change slightly. Previously the Local portion of General Plant, which was nearly 70% of the total cost, was allocated using a "PTD" factor, an allocator internally generated by the CCOSS model, which is the sum of the already allocated production, transmission & distribution original plant costs. The System portion, which was about 30% of the total, was previously allocated with the system peak factor (D10). Now the total will be allocated using a PTD factor.

While Common Plant was also previously separated into System and Local subcomponents, the elimination of that distinction has no affect because both sub-components were previously and currently allocated using the PTD allocator.

Q. HAVE YOU PROVIDED A FURTHER EXPLANATION OF HOW THE CCOSS IS DEVELOPED?

A. Yes. I provide a document titled "Guide to Embedded Class Cost of Service Study," Exhibit No._____(MAP-1), Schedule 3. It provides a useful primer on how the CCOSS was conducted, including the processes of cost functionalization, classification and allocation. These basic processes are common to all embedded cost of service studies. This Guide also describes how each of the cost allocation factors were developed and identifies cost items to which each allocator is applied.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S PROPOSED CCOSS.

A. Table 1 below contains a summary of the information from the CCOSS contained in Exhibit___(MAP-1), Schedule 2. It indicates the cost responsibilities by class and the rate increase that would be necessary to provide an equal rate of return from each class.

Table 1
Summary of Class Cost of Service Study

UNADJUSTED REVENUE REQUIREMENTS

	Total	Residential	Non-Demand	Demand	St Ltg
Unadjusted Rate Revenue Reqt	164,855	67,801	9,633	85,752	1,669
Incr Misc Chrgs & Late Pay	111	44	6	59	1
Unadjusted Operating Revenues	164,966	67,846	9,639	85,811	1,670
Present Rates	146,384	58,453	8,457	78,095	1,379
Unadjusted Deficiency	18,582	9,393	1,182	7,716	291
Defic / Pres	12.7%	16.1%	14.0%	9.9%	21.1%
Ratio: Class % / Total %	**1.00**	**1.27**	**1.10**	**0.78**	**1.66**

ADJUSTED REVENUE REQUIREMENTS (the Proposed Method For Addressing Interruptible Discounts)

	Total	Residential	Non-Demand	Demand	St Ltg
Adjusted Rate Revenue Reqt	164,855	67,894	9,748	85,539	1,674
Incr Misc Chrgs & Late Pay	111	44	6	59	1
Adjusted Operating Revenues	164,966	67,939	9,754	85,598	1,675
Present Rates	146,384	58,453	8,457	78,095	1,379
Adjusted Deficiency	18,582	9,486	1,297	7,503	296
Defic / Adj Pres	12.7%	16.2%	15.3%	9.6%	21.5%
Ratio: Class % / Total %	**1.00**	**1.28**	**1.21**	**0.76**	**1.69**

Q. Why have you referred to “unadjusted” and “adjusted” cost responsibilities?

A. The unadjusted cost responsibilities are those that reflect the historic treatment of interruptible discounts. The adjusted cost responsibilities are the ones proposed for setting rates in this case and reflect the Interruptible Capacity-Cost-Accounting Adjustment I discussed earlier, which re-allocates the interruptible rate discounts as a "capacity-related power supply cost." The difference between interruption capacity costs less interruption rate discounts results in a change in the revenue requirement for each customer class in the "adjusted" CCOSS, but no change in the total revenue deficiency.

B. The Comparison Class Cost Study

Q. HOW IS THE COMPARISON CCOSS DIFFERENT FROM THE COMPANY'S PROPOSED CCOSS?

A. As I indicated earlier, the Comparison CCOSS is essentially the same as the Company's Proposed CCOSS except the C & I Demand class, is separated into "small" and "large" subgroups. Small was defined as customers with a maximum demand of less than 1.0 MW and large was defined as customers with maximum demand of 1.0 MW or greater.

The rates available to C & I Demand customers have service provisions designed to reflect differences in costs associated with (1) service voltage; (2) time-of-use; (3) load factor; and (4) firm versus interruptible. These rates do not (and should not) differentiate between customers based on size or type (i.e. small vs. large, or commercial vs. industrial). Therefore, any subgroup break down of the Demand C & I class in the CCOSS, such as small vs. large, is neither necessary nor useful.

Q. PLEASE EXPLAIN HOW THE COMPANY CHOSE THE SMALL VERSUS LARGE SPLIT FOR PURPOSES OF THIS COMPARISON CCOSS.

A. One of the problems associated with a subgroup break down based on size, is deciding what is "small" and what is "large." For purposes of this comparison CCOSS, the Company used 1.0 MW as the division point. This number was chosen because it is the size-split used for statistical reporting in the Company's FERC Form No. 1 Annual Report. However, it is important to understand that there is no correct/best "small vs. large" division point. Dividing the C & I Demand class using any size/load level (or by Commercial versus Industrial) is an arbitrary distinction, which does not reasonably reflect any cost-of-service difference. A customer's maximum load level is not a service characteristic that determines a difference in the cost per unit (kWh or kW). Therefore, load is not a useful distinction for purposes of developing appropriate rate design for setting intra-class revenue responsibilities.

Q. WHAT ARE THE RESULTS OF THE COMPARISON CCOSS.

A. The summary results of the Comparison CCOSS are contained in Exhibit___(MAP-1), Schedule 4. Detailed results are shown in Exhibit___(MAP-1), Schedule 5. This Comparison CCOSS is essentially the same as that of the Proposed CCOSS except the C & I Demand class is divided into two subgroups, small (less than 1.0 MW) and large (1.0 MW or greater).

III. SELECTED RATE DESIGN REVISIONS

A. Voltage Discounts

Q. WHAT REVISIONS ARE BEING PROPOSED TO THE VOLTAGE DISCOUNTS IN THE C&I DEMAND TARIFFS?

A. The proposed revisions to the voltage discounts are a direct result of the test year 2008 CCOSS results. The results of the CCOSS indicate that the energy charge discounts should be increased to reflect current costs. Analysis of costs for demand charge discounts indicates that a decrease in discounts is warranted. NSP proposes no change in the discounts for primary voltage levels and small decreases in the discounts for transmission transformed and transmission voltage levels. Currently there are no NSP South Dakota customers that receive service at transmission transformed or transmission voltage levels. Table 2 below compares the revenue requirement to the present and proposed voltage discounts for both demand and energy. This Table is a summary of the cost analysis provided in Exhibit____(MAP-1), Schedule 6.

Table 2			
C&I Voltage Discounts - Demand			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
Revenue Req	**$0.41**	**$1.09**	**$1.86**
Present	**$0.80**	**$1.50**	**$2.05**
Midpoint to cost	**$0.604**	**$1.295**	**$1.955**
Proposed	**$0.80**	**$1.30**	**$2.00**
C&I Voltage Discounts - Energy			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
Revenue Req	**0.09¢**	**0.14¢**	**0.20¢**
Present	**0.06¢**	**0.09¢**	**0.12¢**
Proposed	**0.09¢**	**0.14¢**	**0.20¢**

B. Miscellaneous Tariff Consolidation

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TARIFF CONSOLIDATIONS.

A. The Company proposes to consolidate the following:

1. Residential Service - Underground (Sheet 4) consolidated with Residential Service (Sheet 1)
2. Residential Time Of Day Service – Underground (Sheet 5) consolidated with Residential Time Of Day Service (Sheet 2)

Q. PLEASE EXPLAIN THE COMPANY'S REASONS FOR CONSOLIDATING THESE TARIFFS.

A. The two Residential underground tariffs (Non-Time of Day and Time of Day) are identical to the corresponding overhead tariffs except the customer charge is $2.00 per month more under the underground tariff. By adding another Customer Charge line to the corresponding standard tariffs, the two separate underground versions can be eliminated. The Company proposes this consolidation for efficiency and simplicity.

C. Distributed Generation Interconnection Procedures

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO DISTRIBUTED GENERATION FACILITIES?

A. Because of the growing interest in distributed generation ("DG") facilities that are owned and operated by non-utility developers, the Company has developed a document titled "Distributed Generation Interconnection Manual." Its purpose is to provide potential DG developers with technical, contractual and administrative information concerning the interconnection of their DG facilities to the Company's electric distribution system.

This Interconnection Manual is provided in Exhibit No._____(MAP-1), Schedule 7. However, because of its length (sixty five pages), technical nature and because it is of interest to only a very small number of customers, the Company is not proposing to include it in the Rate Book. Instead, to assure that any potential DG developer is aware of its availability, the Company is proposing to add a new tariff titled Interconnection Procedures and Technical Requirements, Sheet No. 10 of Section 9 to its Rate Book. This new tariff indicates the availability of the Distributed Generation Interconnection Manual upon request.

D. General Rules and Regulations

Q. WHAT REVISIONS ARE BEING PROPOSED IN THE GENERAL RULES AND REGULATIONS TARIFFS?

A. The Company is proposing a number of revisions to tariff language and/or service charges contained in its General Rules and Regulations, Section 6 of its Rate Book. In this section of my testimony I provide a description of the proposed revisions and provide the reasons for the revisions. Redline versions of all changes to the General Rules and Regulations are provided in Volume 3.

<u>Application for Service, Section 6.1.1</u>

Q. WHAT REVISIONS ARE BEING PROPOSED TO THE COMPANY'S TARIFFS REGARDING APPLICATIONS FOR SERVICE?

A. The Company is proposing to modify the tariff language to make it consistent with the Company's tariffs in other jurisdictions. The relevant portions, of the tariff read as follows, with the changes indicated by underlining:

> "The Company may refuse an applicant or terminate service to a customer who fails or refuses to furnish information requested by the Company for the establishment of a service account. Any person who uses electric service in the absence of application or contract shall be subject to the Company's rates, rules and regulations, and shall be responsible for payment of all service used.
>
> When required by governmental authority, a customer desiring new service or expanded service must first make application for and receive written approval from the Company.
>
> Subject to its rates, rules, and regulations, the Company will continue to supply electric service until notified by customer to discontinue the service. The Customer will be responsible for payment of all service furnished through the date of the discontinuance."

This format of underlining added text is used in all the discussion of General Rules and Regulations changes below. A copy of the entire proposed tariffs is provided in redline format in Volume 3 of the Application.

Service Charges, Sections 6.1.2.A., B. & C

Q. WHAT REVISIONS ARE BEING PROPOSED TO THE COMPANY'S SERVICE CHARGES?

A. The Company is proposing two changes, which are: (1) a Service Reconnection Charge of $22.50 and; 2) a Service Relock Charge of $100.00.

Q. WHAT IS THE REASON FOR ADDING THE SERVICE RECONNECTION CHARGE?

A. Our analysis of service reconnections indicates a cost of $48.01. The Company is proposing a Service Reconnection Charge of $22.50, which is only part way to this cost level, but makes the charge consistent with the charge in other jurisdictions. The cost analysis supporting these proposed rates is provided in Exhibit No.___(MAP-1), Schedule 8.

Q. WHY IS THE COMPANY PROPOSING TO ADD A SERVICE RELOCK CHARGE?

A. Service relock events are unusual but they do occur. Our analysis of service relocks indicates that the average cost of a relock in the Sioux Falls area is $50.86, and the average cost in the non-Sioux Falls area is $79.94, The Company proposes a higher Service Relock Charge of $100.00 to discourage unauthorized reconnection of service by customers. Unauthorized customer-reconnection of a locked service is dangerous for both the customer and Company employees, who may not realize that a locked service has been re-energized by the customer. The cost analysis supporting these proposed rates is provided in Exhibit No.___(MAP-1), Schedule 8.

<u>Service Charges, Section 6.1.2</u>

Q. DOES THE COMPANY PROPOSE ANY MODIFICATIONS TO ITS TARIFF TO ACCOUNT FOR SEASONAL CUSTOMERS?

A. Yes. The Company is proposing to add the following language to charge seasonal customers the cost of maintaining service during those months when they do not take service. During those months the Company still has investment in place dedicated to serving the customer for which the minimum charge should be assessed upon reconnection. This change will make this electric tariff consistent with the Company's tariff in other jurisdictions:

"If a customer requests reestablishment of service at a location where the same customer discontinued the same service within the preceding 12 month period, an additional reconnection fee will be assessed equal to the sum of the monthly minimum charges applicable during the period service was discontinued."

Optional Metering Service, Section 6.1.5

Q. WHAT REVISIONS ARE BEING PROPOSED TO THE COMPANY'S OPTIONAL METERING SERVICE CHARGES?

A. The Company proposes to modify the language to read:

"The customer's utilization equipment has a total rated capacity of 250 kW or less and an estimated usage of 186,000 kWh or less per month."

This is a change from the existing criteria of 10 kW and 2,500 kWh, which has not been updated since 1984 and is consistent with the types of qualifying equipment in use today. See the redline version of the tariff Volume 3 for a copy of the full tariff provision.

Deposits and Guarantees, Section 6.1.6

Q. WHAT CHANGES ARE THE COMPANY PROPOSING REGARDING ITS DEPOSIT AND GUARANTEE POLICIES?

A. The Company is proposing to delete the entire existing Deposits and Guarantees section language and replace it with the below indicated text. The new language makes clear the requirements and circumstances where customer deposits may be used for settlement of a delinquent bill. The new replacement language is as follows:

> A. General: Any applicant or customer who has not established good credit as defined by the Commission rules may be required to make a deposit to ensure payment before making a service connection.
>
> B. New Service: The Company may require an applicant for service to make a deposit sufficient to cover the estimated charge for furnishing service. If a deposit is required, the Company shall issue a receipt to the depositor showing the amount of the deposit, the date the deposit was made, and the depositor's name.
>
> C. Existing Service: The Company may require a deposit from an existing customer before reconnection is made due to disconnection for nonpayment of a bill. The Company may require a deposit if all or part of the previous deposit was used in settlement of the delinquent bill.

D. Deposit Amount: If a deposit is required, the amount of the deposit shall cover the estimated charge for furnishing service to the customer for a sixty-day period.

E. Payment Guarantee Permissible: In lieu of a cash deposit, a guarantee satisfactory to the Company for a like amount will be acceptable. The Payment Guarantee will terminate when the customer gives notice to discontinue service, there is a change in the location covered by the Payment Guarantee, or sixty days after the Guarantor makes a written request to the Company for termination, or thirty days after the customer has paid their bills for twelve consecutive months without having service disconnected for nonpayment and without receiving three or more disconnection notices.

The Company may require a new Payment Guarantee or cash deposit after termination of a Payment Guarantee.

F. Interest on Deposits and Refunds: On such customer deposits, the Company will pay interest at the rate of seven percent simple interest per annum. The Company will pay interest annually by direct payment or as a credit on the customer's bill, at the option of the Company. The payment or deduction for interest must be made during each calendar year, or whenever a deposit is refunded or service discontinued.

G. Refund of Deposits: The Company will refund the deposit plus accrued interest to the customer if the customer has paid their bills for twelve consecutive months without having service disconnected for nonpayment and without receiving three or more disconnection notices.

H.Additional Requirements: If a customer's credit standing becomes unsatisfactory after a deposit has been refunded or if the deposit is inadequate to cover 60 days of the estimated annual bill, a new or additional deposit may be required upon reasonable written notice by the Company. Deposits will not be considered advance payments on account. Service to a customer who fails to comply with these requirements may be discontinued upon reasonable written notice.

In case of discontinuance of service or non-payment of amounts payable when due, the Company will not restore service until all arrears are paid in full and a cash deposit as required above is made, or until other satisfactory credit arrangement is made.

Service Calls, Section 6.1.7

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO RESPONDING TO TROUBLE CALLS?

A. The Company is proposing modifications to the language to make it gender-neutral. The modified language would read:

"When a customer calls and reports an electrical problem, the Company will, as soon as possible, send out <u>service personnel</u> to determine the necessary action to correct the problem.

If the electrical problem is in the customer's facilities, the <u>service personnel</u> will attempt to restore service by fuse replacement or minor temporary repair. The customer will be charged for all <u>related costs including labor and all</u> materials furnished

C. Storm conditions require the presence of service <u>personnel</u> in the customer's vicinity and the Company dispatcher notified the service <u>personnel</u> when dispatched to waive charges.

Additionally, the Company is proposing to eliminate the prescribed hourly charges for trouble calls because the circumstances under which they were originally developed and under which they were applied have essentially disappeared over time. As a result these hourly rates are no longer needed.

Q. PLEASE EXPLAIN WHY THESE HOURLY RATES ARE NO LONGER NEEDED; DOESN'T THE COMPANY RESPOND TO TROUBLE CALLS?

A. Yes, the Company continues to respond to trouble calls. To explain why these prescribed hourly charges are no longer needed it is helpful to group trouble calls into two categories.

In the first category are those where the electrical problem originates in the Company's facilities. In these cases, the problem would be identified and resolved without a charge to the customer. This category of trouble calls makes up the majority of calls and includes calls concerning suspected low voltage and power outages. The hourly charges do not apply to this first category, but they would occasionally apply to the second category of calls.

The second category is where the electrical problem is determined to be on the customer's side of the meter. For events that fall into this category, the Company's technician might make a minor repair, such as fuse replacement, to restore service after determining that the problem was on the customer's side of the meter. But more frequently the technician will identify the problem and refer the customer to an electrician or appliance repair person. Instances in which the Company's technician makes a repair for problems on the customer's side of the meter have declined since the 1980's to the point where they are essentially nonexistent. Therefore, there is no longer a need for this charge.

Q. WHY HAVE THESE OCCURANCES ESSENTIALLY DISAPPEARED OVER THE YEARS?

A. There are probably a number of reasons for this decline but two likely reasons would be the following. The first is the change in the technology of home wiring, where fuses have been replaced with re-settable circuit breakers. These circuit breakers make it easy and convenient for customers to resolve most electrical outages inside the home. At one time, blown fuses were a cause of a number of customer trouble calls and the solution was a replacement of the fuse sometimes performed by the Company's technicians.

Another reason for the decline may be the Company's practice of interviewing customers when they initiate a service call in order to assess the probable cause of the problem before dispatching a technician to investigate. By carefully interviewing a customer when a call is initiated, the Company can better determine whether the problem is on the customer's side of the meter and advise the customer on an appropriate course of action to resolve the problem. For example, the customer may be advised to check their circuit breakers or fuses. The customer may also be advised that because the Company's technicians do not repair appliances or repair home wiring the customer may need to hire an electrician or appliance repair person to correct the problem.

In any case, the Company's experience over the past two decades is that the incidents of this second category of trouble calls where charges were assessed have fallen to essentially zero. Therefore, the Company proposes deleting these prescribed hourly charges from the tariff and instead handle the rare event where a Company technician does work on the customer's side of the meter with a charge for actual time and materials.

Dedicated Switching - Section 6.1.8

Q. WHAT IS DEDICATED SWITCHING SERVICE?

A. Dedicated Switching is a service only a few large C&I customers request. It typically occurs when customers need to work on their own facilities and doing so requires that the electric service be de-energized. This service also takes place at a customer-specified date and time, which is often outside of normal business hours. Providing this service requires taking a service crew off of normal work and dispatching them to de-energize the service so the requesting customer can do its work. Then the Company's crew restores the customer's service as soon as the customer completes its own work. The Company proposes adding charges for this service to reflect the current costs for providing this service.

Q. WHAT RATES DOES THE COMPANY PROPOSE FOR THIS SERVICE?

A. The Company proposes an hourly rate for this service of $250.00 when performed Monday through Saturday and a rate of $300.00 when performed on Sundays and Federal holidays. The cost analysis supporting these proposed rates is provided in Exhibit No.___(MAP-1), Schedule 8.

Classification of Customer, Section 6.2.1

Q. DOES THE COMPANY PROPOSE ANY MODIFICATIONS TO ITS CUSTOMER CLASSIFICATION TARIFF?

A. Yes. As I outline further below, the Company proposes a number of modifications to clarify the tariff's intent.

Section 2.1A – Residential Customer will read:

> "A residential customer is one using electric service for general household purposes in space occupied as living quarters such as single private residences, single apartments, fraternity houses, sorority houses, and for garages or other auxiliary buildings on the same premises used by the residential customer. General household purposes or uses are domestic lighting, heating, cooking and power service."

Section 2.1B – Farm Customer will read:

"A farm customer taking electric service for non-general household purposes only may be considered a general service customer for rate application purposes. A farm customer using electric service for general household and non-general household purposes jointly may combine such uses through one meter on such rates as are available to general service customers or farm customers. However, where such use is combined and the non-general household electric equipment totals less than one kilowatt of connected load, such farm customer shall be classified residential. Where electric equipment is used jointly for general household and non-general household purposes (such as a water pump), the major use of such equipment will determine whether it is classified for general household or non-general household uses."

Section 2.1C – General Service (Commercial) Customer will read:

"A general service customer is one using electric service for any non-general household purpose in space occupied and operated for commercial purposes, such as stores, offices, shops, hotel, garages, wholesale houses, filling stations, barber shops, beauty shops, and any other space occupied for commercial purposes."

Section 2.1D – "Small Commercial and Industrial Customer" is new and defines the application of this classification. The proposed language is as follows:

> "<u>A Small Commercial and Industrial Customer has an actual demand less than or equal to 100 kW.</u>"

Section 2.1E – "<u>Large Commercial and Industrial Customer"</u> is new and defines the application of this classification. The proposed language is as follows:

> "<u>A Large Commercial and Industrial Customer has an actual demand greater than 100 kW.</u>"

<u>Choice of Optional Rates, Section 6.2.3</u>

Q. WHAT ARE THE COMPANY'S PROPOSED TARIFF PROVISIONS REGARDING CHANGES TO ANY CUSTOMER RATE SCHEDULES?

A. The Company is proposing one minor modification to clarify the intent of the tariff.

> "The Company may not be required to move a customer's service to a different a rate schedule more often than once in <u>twelve</u> months unless <u>the rates are changed, there is a material change in the customer's load, or</u> another change is necessary as a result of an order issued by the Public Utilities Commission or a court having jurisdiction."

<u>Standby, Supplementary, Emergency, & Incidental Services, Section 6.2.4</u>

Q. DOES THE COMPANY PROPOSE ANY LANGUAGE CHANGES TO ITS STANDBY, SUPPLEMENTARY EMERGENCY AND INCIDENTAL SERVICES TARIFFS?

A. Yes the Company proposes the following administrative language revisions to make the language gender-neutral and to more accurately reflect how this service is provided to customers.

> Unless otherwise specifically provided, the Company's rate schedules require that the customer's entire electrical requirements be received from the Company.
>
> A. Definitions
>
> 1. *Standby Service* is defined as service available on a firm (scheduled or unscheduled) basis or non-firm basis through a permanent connection to supply replacement electric energy and power when the customer's normal source of electric energy supply is not available.
>
> 3. *Emergency Service* is defined as service supplied through a temporary connection when the customer's usual source of supply has failed.
>
> C. Parallel Operations
>
> 3. The customer will provide the necessary equipment as approved by the Company to enable the customer to operate customer's independent source of power in parallel with Company's system. The customer shall not energize a de-energized portion of the Company's system without permission from the Company.

> 4. Since the power factor and the voltage at which the Company's system and a customer's system are operated will vary, each party agrees to operate its system at a power factor as near unity as possible, or other mutually agreed upon power factor level, in such manner as control its share of the reactive power, and voltage as conducive to the best operating standards.

Monthly Billing, Section 6.3.3

Q. WHAT CHANGES ARE PROPOSED TO THE COMPANY'S MONTHLY BILLING TARIFFS?

A. The Company is proposing one modification to more precisely describe Company practice.

The proposed modification clarifies current Company practice as follows:

> "If the billing period is longer or shorter than the normal billing period by more than five days, the bill shall be prorated on a daily basis except for the November, December, and January billing periods when the bill shall be prorated on a daily basis whenever the billing period is less than 25 days or more than 40 days."

Late Payment Charge, Section 6.3.5

Q. WHAT REVISIONS ARE BEING PROPOSED TO THE COMPANY'S LATE PAYMENT CHARGES?

A. The Company is proposing two changes to clarify the language and more accurately reflect current practice. The first proposed change is in the assessment of the late payment charge as indicated below. It makes the tariff consistent with the current billing system process.

> "A late-payment charge of 1.<u>0</u>% of the unpaid balance will be added to the unpaid balance <u>two working days</u> after the date due."

The second proposed change clarifies the application of the Late Payment Charge and deletes the redundant "Assessment Date" table. The new language reads as follows:

> "<u>Customers under the Budget Helper Plan or a payment arrangement will be assessed a late payment charge on the lesser of the outstanding scheduled payments or the outstanding account balance.</u> All payments received will be credited against the oldest outstanding total account balance before application of the late payment charge. The late payment charge will be <u>waived in instances where a Company error is involved or where complications arise with financial institutions in processing automatic electronic payments</u>."

<u>Bill Date Due, Section 6.3.6</u>

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS BILL DATE DUE TARIFFS?

A. Yes. The Company is proposing two changes to this Bill Date Due section. The first involves changes in the language that specifies the "Date Due" for bills so as to more accurately reflect actual billing system practices. For the details, see the redlined version of the language in Volume 3 of the Application.

The second change is the following additional language that addresses requirements associated with the option for customers to modify their bill due date. There are administrative burdens associated with changing due dates and customers should not be allowed to change their billing dates more frequently than annually.

> "Residential and Small General Service customers have the option of selecting a modified due date for paying their bill. The due date can be extended up to a maximum of 14 calendar days from the normal date<u>. A customer selecting a modified due date will remain on that due date for a period not less than 12 months unless the customer elects to change back to the normal due date anytime.</u>

<u>Billing Adjustments, Section 6.3.8</u>

Q. WHAT CHANGES ARE BEING PROPOSED TO THE BILLING ADJUSTMENT TARIFFS?

A. The Company is proposing a number of changes to this section including the addition of new language, and deletion of some existing language and format changes so as to provide clarity.

The proposed language changes describe how billing adjustments are handled for several different types of metering and billing problems. For a view of the details of the proposed language changes, please see the redlined version of the tariff in Volume 3 of the Application.

Account History Charge, Section 6.3.10

Q. IS THE COMPANY PROPOSING ANY INCREASES TO ITS ACCOUNT HISTORY CHARGE?

A. Yes. The Company is proposing to increase this charge from $1.00 to $5.00 to reflect current costs. The analysis of this activity indicates that the current costs are approximately $2.44 per account. However, this cost analysis, which is based on a generic low-cost example, does not reflect actual requests, which are generally more complex and, therefore, cost more. Also, the proposed $5.00 charge will make it consistent with the charge in other jurisdictions. See my Exhibit No. __(MAP-1), Schedule 8, for cost information.

Synchronized Bill Service, Section 6.3.11

Q. WHAT NEW SERVICE IS THE COMPANY PROPOSING TO OFFER?

A. The Company is proposing this new optional Synchronized Bill Service. It allows customers with multiple accounts to receive one consolidated bill for all of their accounts. See the red lined version of the proposed tariff in Volume 3 of the Application for details.

Use of Service, Section 6.4.1

Q. HOW DOES THE COMPANY PROPOSE TO CHANGE ITS USE OF SERVICE TARIFF?

A. The Company is proposing a number of minor changes to the language of this tariff to clarify the tariff intent, provide consistency with current Company practice, and to correct spelling.

The first two language changes are found in 6.4.1A. Definitions as follows:

6.4.1A.2. "<u>Master Metering or</u> Redistribution.

6.4.1A.4. "<u>Resale</u>."

The third language change is found in the second paragraph of 6.4.1.B. General Rules:

> "Electricity is supplied for use by customer's household or business, and <u>resale</u> or submetering of such service is not permitted. <u>The Company permits master metering where allowed by law, but a landlord may not charge the tenants more than the landlord is charged by the Company.</u>"

There are additional language changes in 6.4.1B, 6.4.1.C and 6.4.1.D to clarify the tariff intent. Please see the red lined version of the proposed tariff in Volume 3 for details.

<u>Customer's Wiring, Equipment, and Property, Section 6.4.2</u>

Q. WHY IS THE COMPANY CHANGING ITS TARIFFS REGARDING CUSTOMER'S WIRING, EQUIPMENT AND PROPERTY?

A. The Company is proposing minor language changes to make this tariff gender-neutral and to clarify its intent. The modified portion of the tariff is proposed to read as follows:

> "The Company may, however, at any time require a customer to make such changes in <u>customer's</u> electrical or non-electrical property or use thereof as may be necessary to eliminate any hazardous condition or any adverse effect which the operation of the customer's property or equipment may have on <u>said</u>

<u>customer, other customers of the Company, the public, or</u> the Company's employees, equipment or service."

<u>Standard Installation, Section 6.5.1.A</u>

Q. WHAT REVISIONS ARE BEING PROPOSED TO THE COMPANY'S STANDARD INSTALLATION TARIFFS?

A. The Company is proposing a number of revisions to the language and service charges contained in its Standard Installation tariffs. The more important of these revisions are discussed below. For a view of all the changes, see the redline version of this tariff in Volume 3 of the Application

The Company is proposing two revisions to the language of this Section.

The first modification is in the last sentence of the second paragraph where it is modified to make it gender neutral as follows:

> "The facilities installed by the Company shall be the property of the Company, and any payment by customer will not entitle <u>the customer</u> to any ownership interest or rights therein."

The second revision involves language changes in the third paragraph to clarify the tariff intent:

> "Unless otherwise stipulated in the applicable agreement or service form, <u>and</u> prior to any installation by the Company, <u>the customer is required</u> to provide the necessary right-of-way for the installation of the Company's facilities…."

Standard Installation (continued), Section 6.5.1A.1.a.

Q. ARE ANY OTHER MODIFICATIONS TO THE STANDARD INSTALLATION TARIFFS PROPOSED?

A. The Company is proposing three modifications to this section to provide consistency with current Company practice and to clarify the tariff language.

The first change is to reinforce the fact that the allowable footage for residential extensions involves only the service lateral, not a distribution lateral, nor a combination of a service and distribution lateral.

> "Company will extend, on private property, to a Company-designated service location, a service lateral a maximum distance of 100 feet."

The second change is to eliminate the language relating to the "three-times revenue" rule for determining the construction allowance since this provision does not apply in individual Residential service extensions. The Company proposes to replace this language with the following:

> "When the necessary extension to a Company designated service location exceed these limits, the customer will be charged for the additional extension according to the Excess Footage Charge set below."

The proposed excess footage charge is $6.85 per-circuit-foot and is based on current costs as shown in Exhibit No.___(MAP-1), Schedule 8.

The third change is to clarify the application of the excess footage charge when the customer requests a preferred service location that is beyond the Company-designated service location as follows:

> "Customers requesting a preferred service location will also be charged the Excess Footage Charge for each circuit foot Company extends the installation beyond Company's designated service location."

Standard Installation (continued), Section 6.5.1.A.1.b

Q. WHAT REVISIONS TO THE "OTHER THAN RESIDENTIAL" SECTION OF THE STANDARD INSTALLATION TARIFFS ARE PROPOSED?

A. The Company is proposing the following two modifications to the "Other than Residential" section of the service extension rules. See the redlined version of the proposed tariff in Volume 3 of the Application for more details.

The first modification is to the language relating to the current "three-times revenue" rule for determining the construction allowance for distribution lateral extensions. The relevant portion of the tariff has been modified to read:

> "…must not exceed a sum equal to three and one half (3.5) times the customer's anticipated annual revenues, excluding the portion of the revenue representing fuel-cost recovery."

The second change is to clarify the situation where the extension costs exceeds 3.5 times the customer's anticipated annual revenue. The relevant portion of the tariff has been modified to read:

"When the cost of the necessary extension exceeds this limit, the customer will be charged the difference."

Q. WHAT IS THE RATIONALE FOR THIS REVISION TO THE THREE-TIMES REVENUE RULE?

A. Historically, applying the "three-times revenue" rule to total revenues (including fuel-cost recovery revenues) was reasonable because the fuel-cost recovery portion of total cost-of-service was relatively small and stable over time. In recent years, however, market-driven fuel and purchased energy costs have escalated rapidly and may continue to do so. Fuel cost recovery revenues were removed to prevent over charging, but that, in turn, requires an increase in the multiplier to 3.5 to reflect its application to a smaller revenue base. The purpose of this modification is to adjust the "three-times revenue" rule so that future construction-allowances for distribution extensions do not become out of proportion to what they have been historically. Without this modification, customers who should provide a contribution in aid of construction ("CIAC") would not be required to do so. As a consequence, the distribution rate base investment would grow faster than it should because unusually costly extensions where a CIAC would have been imposed would be absorbed into rate base, and all customers would pay for these excess extension costs.

Standard Installation (continued), Section 6.5.1A.2

Q. ARE ANY CHANGES TO THE WINTER CONSTRUCTION TARIFF PROPOSED?

A. Yes. The Company is proposing changes to its Winter Construction tariff to more accurately reflect current practice and the associated costs and to provide consistency with the Company's other jurisdictions. The proposed changes provide clarification to winter construction projects, both electric only and where it is a combination electric and gas winter construction project. The proposed language is as follows:

> "When underground facilities are installed between October 1 and April 15, inclusive, because of failure of customer to meet all requirements of the Company by September 30, or because the customer's property, or the streets leading thereto, are not ready to receive the underground facilities by such date, such work will be subject to a Winter Construction Charge when winter conditions of six inches or more of front exist, snow removal or plowing is required to install service, or burners must be set at the underground facilities in order to install service for the entire length of the underground service. Winter construction will not be undertaken by the Company where prohibited by law or where it is not practical to install underground facilities during the winter season. The charges immediately below apply to frost depths of 18" or less. At greater frost depths, the Company may individually determine the job cost. The Company reserves the right to charge for any unusual winter construction expenses. All winter construction charges are non-refundable and are in addition to any normal construction charges.

WINTER CONSTRUCTION CHARGE

Thawing	$400.00 per frost burner
Service, primary or secondary	

distribution extension $3.00 per trench foot"

The cost support for these charges is included in Exhibit No.____(MAP-1), Schedule 8.

Standard Installation (continued), Section 6.5.1A.3.

Q. DOES THE COMPANY PROPOSE TO DELETE ANY EXISTING TARIFF PROVISIONS?

A. Yes. The Company is proposes to delete this section on "Excess Capital Expenditures" that is redundant with 6.5.1A.4 and to be consistent with other jurisdictions.

Standard Installation (continued), Section 6.5.1A.4.

The Company is proposing to change the section title to "Unusual Installation Costs" to clarify that this section addresses non-standard installation costs. In addition, the format has been changed to make it easier to understand. See the redlined version in Volume 3 of the Application for details.

Standard Installation (continued), Section 6.5.1.B

Q. WHY DOES THE COMPANY PROPOSE TO CHANGE THIS SECTION?

A. The Company is proposing minor language modifications to make it gender neutral. These changes are shown in the redline version of the tariff in Volume 3 of the Application.

Standard Installation (continued), Section 6.5.2

Q. WHAT CHANGES DOES THE COMPANY PROPOSE TO THIS SECTION?

A. The Company is proposing five changes to clarify the tariff intent and provide consistency with current Company practice and with the above-described changes in the three-times revenue rule.

The first change to the relevant portion of the first paragraph in Section 6.5.2 is as follows:

> "….the Company will extend, enlarge, or change its distribution or other facilities for supplying electric service when the product of three and one half (3.5) times the anticipated annual revenue, excluding the portion of the revenue representing fuel-cost recovery from the sale of additional service…."

The second change is in Section 6.5.2A. as follows:

> "Pays to the Company the portion of the capital expenditure not justified by the product of three and one half (3.5) times the anticipated annual revenue, excluding the portion of revenue representing fuel-cost recovery (with or without provision for refund of all or part of such payment)…."

The third change is in the last paragraph and clarifies a non-refundable customer charge. It reads as follows:

> "Non-refundable payments will be in the amount determined by subtracting from the total estimated installation cost the product of three and one half (3.5) times the anticipated annual revenue, excluding the portion of the revenue representing fuel-cost

> recovery as set forth in Section 5.1, STANDARD INSTALLATION." .

The fourth change is also found in the last paragraph and includes language to clarify the application of refundable payments and how the payments will be refunded. It reads as follows:

> "Additional refundable payments may be required where service is extended and where customer occupancy is expected to be delayed. In such cases, for each additional customer served directly from the original contracted extension within five (5) years from the date of its completion, the person who made the advance payment will receive proportionate refunds as additional customers take occupancy. The total of such refunds will in no event exceed the total refundable advance payment. Refunds will be made only for line extensions on private property to a single customer served directly from the original contracted facilities."

The fifth proposed change is to reformat Section 6.5.2 for clarification. See the redlined version of the proposed tariff in the Volume 3 of the Application for details.

Special Facilities, Section 6.5.3

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO ITS SPECIAL FACILITIES TARIFF?

A. Yes. The Company is proposing one minor change to this section to make the last sentence of the second paragraph gender neutral as follows:

> "Any payment by a customer will not entitle the customer to any ownership interests or rights therein."

Replacement of Overhead with Underground and Service Connections, Sections 6.5.5 and 6.5.6 Respectively

Q. WHY IS THE COMPANY PROPOSING CHANGES TO THIS TARIFF?

A. The changes in this tariff are minor text changes to make the language gender-neutral. The changes in redline format are shown in Volume 3 of the Application.

Temporary Service, Section 6.5.7

Q. DOES THE COMPANY PROPOSE TO MODIFY THE TERMS FOR PROVIDING TEMPORARY SERVICE?

A. Yes. The Company proposes a minor text addition to address advance payments related to customer-requested temporary service. The proposed additional language reads:

> "The Company may require the customer to make an advance payment sufficient to cover the estimated cost of service as described above."

Refusal or Discontinuance of Service, Section 6.6.1

Q. WHY DOES THE COMPANY PROPOSE CHANGES TO ITS TARIFF REGARDING THE REFUSAL OR DISCONTINUATION OF SERVICE?

A. The Company is proposing changes to the language of this section of the electric tariff to make it consistent with other jurisdictions. The Company proposes to delete the first two paragraphs and replace it with the following:

With notice, the Company may refuse or discontinue for any of the following reasons: (1) failure to pay amounts payable when due, when the amount outstanding equals or exceeds the amount of the customer's deposit; (2) failure to meet the Company's deposit or credit requirements; (3) breach of contract for service; (4) failure to provide Company with reasonable access to its property or equipment; (5) failure to make proper application for service; (6) failure to comply with any of the Company's rules on file with the Public Utilities Commission; (7) if the customer has failed to furnish service equipment, and/or rights-of-way necessary to serve the customer as specified by the Company as a condition of service; (8) when necessary to comply with any order or request of any governmental authority having jurisdiction; and (9) when determined by the Public Utilities Commission as prescribed by relevant state or other applicable standards.

Upon such notice as is reasonable under the circumstances, the Company may temporarily discontinue electric service when necessary to make repairs, replacements, or changes in the Company's equipment or facilities.

Without notice, the Company may disconnect electric service to any customer: (1) for unauthorized use or if the customer has tampered with the Company's equipment; or (2) in the event a condition appears to be hazardous to the customer, to other customers, to the Company's equipment, or to the public. Any discontinuance of electric service will not relieve the customer from customer's obligations to the Company.

Curtailment or Interruption of Supply, Section 6.6.2

Q. ARE THERE ANY CHANGES TO THE TARIFF REGARDING CURTAILMENT OR INTERRUPTION OF SUPPLY?

A. The changes in this tariff are minor text changes to make the language gender-neutral. The changes are shown in red line format in Volume 3 of the Application.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications & Experience

Michael A. Peppin

I graduated from the University of Minnesota Twin Cities Campus in 1978 with a Bachelor of Arts degree in Psychology, and in 1980, with a Master of Business Administration degree with an emphasis in Marketing and Statistics.

From October 1979 to December 2000 I was employed with Xcel Energy and its predecessor company Northern States Power Company ("NSP") in the positions of Principal Market Research Analyst (10 years), Market Research Manager (10 years) and Manager, Product Development Support (1½ years). In those positions my responsibilities included conducting research to develop and evaluate NSP's Demand-Side Management programs, including NSP's interruptible and time-of-day rate programs. In January 2001, I accepted the position of Market Research Manager for Xcel Energy's unregulated broadband telecommunications subsidiary, Seren Innovations. My responsibilities involved research regarding the development, pricing and marketing of telecommunications products and services. With Xcel Energy's announced intention to sell Seren Innovations to external buyers, I accepted the position of Senior Market Research Manager with Cargill Corporation in February 2004. In that position I conducted market research studies for many of Cargill's business units, including its Power Marketing unit. Finally, in December 2006 I resumed employment with Xcel Energy in the Pricing and Planning Department as a Principal Pricing Analyst.

My current job responsibilities include conducting Class Cost of Service Studies for various Xcel Energy jurisdictions and various pricing function support for the utility operating subsidiaries of Xcel Energy.

Summary of Class Cost of Service Study Results ($000) - Proposed Customer Classes

UNADJUSTED REVENUE REQUIREMENTS

		Total	Residential	Non-Demand	Demand	Street Ltg
1	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 2)	164,855	67,801	9,633	85,752	1,669
2	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	111	44	6	59	1
3	Unadjusted Operating Revenues (line 2 + line 3)	164,966	67,846	9,639	85,811	1,670
4	Present Rates (CCOSS page 2, line 3)	146,384	58,453	8,457	78,095	1,379
5	Unadjusted Deficiency (line 3 - line 4)	18,582	9,393	1,182	7,716	291
6	Defic / Pres (line 5 / line 4)	12.7%	16.1%	14.0%	9.9%	21.1%
7	**Ratio: Class % / Total %**	**1.00**	**1.27**	**1.10**	**0.78**	**1.66**

INTERRUPTION REVENUE DISCOUNTS Vs INTERRUPTION CAPACITY COSTS

		Total	Residential	Non-Demand	Demand	Street Ltg
8	Interruption Rate Discounts (CCOSS page 2, line 6)	2,128	727	2	1,399	0
9	Interruption Capacity Costs (CCOSS page 2, line 7)	2,128	820	117	1,186	5
10	Revenue Requirement Shift (line 9 - line 8)	0	93	115	(213)	5

ADJUSTED REVENUE REQUIREMENTS

		Total	Residential	Non-Demand	Demand	Street Ltg
11	Adjusted Rate Revenue Reqt (line 1 + line 10)	164,855	67,894	9,748	85,539	1,674
12	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	111	44	6	59	1
13	Adjusted Operating Revenues (line 11 + line 12)	164,966	67,939	9,754	85,598	1,675
14	Present Rates (line 4)	146,384	58,453	8,457	78,095	1,379
15	Adjusted Deficiency (line 13 - line 14)	18,582	9,486	1,297	7,503	296
16	Defic / Adj Pres (line 15 / line 14)	12.7%	16.2%	15.3%	9.6%	21.5%
17	**Ratio: Class % / Total %**	**1.00**	**1.28**	**1.21**	**0.76**	**1.69**

PROPOSED REVENUE REQUIREMENTS

		Total	Residential	Non-Demand	Demand	Street Ltg
18	Proposed Rates (CCOSS page 3, line 3)	164,856	66,864	9,640	86,776	1,576
19	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	111	44	6	59	1
20	Proposed Operating Revenues (line 18+ line 19)	164,967	66,908	9,646	86,835	1,577
21	Proposed Increase (line 20 - line 14)	18,583	8,455	1,189	8,740	198
22	Difference / Pres (line 21 / line 14)	12.7%	14.5%	14.1%	11.2%	14.4%
23	**Ratio: Class % / Total %**	**1.00**	**1.14**	**1.11**	**0.88**	**1.13**

GUIDE TO EMBEDDED ELECTRIC CLASS COST OF SERVICE STUDY

I. Preliminary Discussion of Information Flow

This document primarily discusses the Class Cost of Service Study ("CCOSS"). But to give the CCOSS a proper perspective, it's necessary to first briefly discuss the three steps of information flow that occur within a rate case. First, the utility's plant assets must be "functionalized." Functionalizing relies on FERC rules and definitions to first divide the utility's assets between the gas and electric utilities. Then the assets of each utility are further divided into six FERC categories. (Please see Attachment 1.) The first four categories (Production, Storage, Transmission and Distribution) roughly follow the flow of energy, from its creation or extraction all the way to its consumption by end users. The fifth category, General, refers to plant items that are strictly related to a single utility but which relate to two or more of the first four categories (e.g., a utility office building that is used only by electric employees or only by gas employees). The sixth category, Common, is similar to General in that it refer to two or more of the first four categories. But Common plant also relates to both the gas and electric utilities (e.g., the Company's General Office building in downtown Minneapolis).

The second rate case information flow involves a Jurisdictional Cost of Service Study ("JCOSS"). A JCOSS takes all the functionalized plant items, as well as all expense items, and splits those costs among the jurisdictions (i.e., states). And the third flow involves using the CCOSS to further split each state-level cost element into the amount for each customer class. (Please see Attachments 2 and 3 for different portrayals of this cost process.)

II. Introduction to Class Cost of Service Study

A fully distributed, embedded CCOSS apportions ("allocates") the total cost of providing utility service ("revenue requirements") to the various service classes in a way that reflects the engineering and operating characteristics of the electric utility system. Given these electric utility cost characteristics, the objective of the CCOSS is to determine for each service class the total costs of service, which includes the costs associated with investment in plant as well as operating expenses. (Please see Attachment 4.)

Xcel Energy's CCOSS is divided into five sections. (Please see Attachment 5.)

The Summary section contains three pages. Page 1 contains a high-level summary of the Rate Base and Income Statement. Pages 2 and 3 both show billing components, such as the customer charge, demand charge and energy charge. However, Page 2 derives these billing components by assuming each customer class provides the same return on investment ("ROI"). In other words, these are "ideal" rates. Page 3 contains more "real world" rates that reflect the variations in ROI that customer classes are actually allowed to pay. (Note that throughout most of the rate case process, these will be labeled "Proposed" rates. But once the Minnesota Public Utility Commission has issued an order, a revised version of the CCOSS would label these as "Ordered" rates.)

The Rate Base section contains three pages. Page 4 shows Original Plant in Service. The top half of Page 5 shows Accumulated Depreciation. This page and a half contain most of the Rate Base dollars, and the resulting Net Plant amount comes close to being the final Rate Base amount. However, certain adjustments must still be made. The bottom half of Page 5 contains subtractions, which currently consists solely of Accumulated Deferred Income Taxes. Page 6 contains additions. These are primarily Construction Work in Progress ("CWIP" which is pronounced "see-wip"). However, there are also some other miscellaneous additions. From a general accounting perspective, Rate Base is fairly similar to the Balance Sheet that non-utilities include in their annual reports.

The Income Statement section contains five pages. It would be possible to have two complete, 5-page Income Statements – one for Present rates and one for Proposed / Ordered rates. But since nearly all the lines would be identical, it has proved more efficient to combine them into a single, joint Income Statement. Generally speaking, an income statement consists of "revenues minus expenses." In this case, all the revenues are shown on the top of Page 7. Revenues can be divided into Retail Revenues, Other Retail Revenues and Other Operating Revenues. While the first category contains only a few lines, it contains the most dollars. These are the actual prices that will be determined as part of the rate case. The second and third categories contain many small, miscellaneous revenue sources. To the extent the utility receives Other Retail Revenue or Other Operating Revenue, the amount of Retail Revenue that the utility needs to collect is reduced.

Expenses begin on the bottom of Page 7, specifically Fuel and Purchased Power costs, as well as Transmission. Page 8 contains Distribution and other miscellaneous expenses. Note that the expenses on these two pages are collectively termed Operating and Maintenance (or "O & M") expenses. The top half of Page 9 contains Book Depreciation. (This is the current year's portion of the Accumulated Depreciation on Page 5.) The bottom half of Page 9 contains Property Taxes. The top half of Page 10 contains the Provision for Deferred Income Taxes. (This is the current year's portion of the Accumulated Deferred Income Taxes on Page 5.) The bottom half of Page 10 contains the Current Inventory Tax Credit (which has almost been phased out by the Federal Government). This page then also shows a Total Operating Expense subtotal, which is based on all the expenses on Page 7 through 10. This expense subtotal is subtracted from total revenues to derive Operating Income Before Income Tax. It's helpful to imagine this final subtotal being "on hold" for a moment, while income taxes are determined.

The top half of Page 11 contains Tax Depreciation (similar to the Book Depreciation on Page 9). The bottom of Page 11 determines total income tax deductions and additions and applies them to Operating Income Before Income Tax (from Page 10) to derive Taxable Income. The utility's corporate tax rate is applied to Taxable Income, to derive Income Tax. Only then does the "revenues minus expenses" process resume, as Income Tax is subtracted from Operating Income Before Income Tax, to derive Preliminary Present and Proposed / Ordered Return. An adjustment is made for Authorized Funds Used During Construction ("AFUDC" or "AFC"). Note that this is essentially imputed income. The final result is simply Present and Proposed / Ordered Return. These total return amounts are compared against the total Rate Base to get the Return On Rate Base percentage. And the common shareholder portion of the return is compared to the common shareholder portion of rate base to get the Common Return percentage.

The Miscellaneous Calculations section contains two pages. The top half of Page 12 contains a full development of AFUDC. The bottom half of Page 12 contains the Labor Allocator. And Page 13 develops various revenue components of Present, Proposed / Ordered and Equal Revenue. The importance of this last page will be discussed later.

The Allocators section contains three pages. Page 14 contains Internal Allocators. These are allocators that can't be fully known prior to the running of the CCOSS because they are based on elements that only come together within the CCOSS. Page 15 contains External Allocators. These allocators are typically based on independent studies (such as the sales forecast) and can thus be fully known prior to the running of the CCOSS. For both of these pages, there is a block of lines containing the "raw" numbers (e.g. one line might contain the number of customers in each class). And there is a corresponding block of the allocator percents. Note that the code names that appear on these pages correspond to the codes shown in the "Alloc" column of pages 4 through 12. Lastly, Page 16 contains a number of constants, such as the components of the utility's capital structure.

III. Splits To Billing Component and Unbundled Component

It has already been noted that the CCOSS splits total costs in at least two "dimensions," namely FERC functionalization and customer class. But to properly identify all costs, they must be split into two additional dimensions. They must be split into billing component (customer charge, demand charge and energy charge). And they must be split into unbundled business unit components (Generation Company or Genco, Transmission Company or Transco, Distribution Company or Disco, and Customer Company or Cusco). However, the CCOSS is processed in a spreadsheet – which has only three dimensions. To accommodate the four required dimensions, the last two components share a dimension. (Please see attachment 6.) In the 3-D view of the spreadsheet, the 500 some JCOSS numbers are placed in a single column on the "surface" of the cube. They are then allocated to the right, to the classes. Then each class amount is allocated down, to billing and unbundling components.

Many of the billing and unbundling components just mentioned are actually broken into subcomponents. E.g., the energy charge is broken into on-peak and off-peak. Likewise, customer charge is broken into the service drop (the wiring and metering that connect the customer to the electric grid) and energy services (meter reading and billing services). And generation demand is divided into base load, summer peaking and winter peaking. The full set of relationships is shown in Attachment 7. All the lower level components (which are in non-bold font) can either be added upwards, to get unbundled business units, which in turn can be added to the left, to get the grand total. Or the lower level components can be added to the left, to get billing components, which in turn can be added upwards, to get the same grand total. Note that while 20 distinct cost items appear on Attachment 7, only 18 layers exist in the spreadsheet on Attachment 6. That's because Transco and Transmission are actually identical and only need a single spreadsheet layer. The same is true for Cusco and Customer.

Because of the complexity of these cost allocation relationships, there is great potential for formula errors in the spreadsheet. To deal with that problem, check sums were installed throughout the spreadsheet. The sums not only verify that the layers add up for each line. They also verify that the class columns add back up to the initial JCOSS amount. While this process catches virtually any error that is introduced into the file, it also makes changing the program very difficult. Nearly every allocated line becomes part of a subtotal that is used to form an additional allocator. Therefore, an allocation error on one line will often cause additional errors on a few dozen other lines. However, when presented with so many errors, it can be quite difficult to go backward and determine which is the "real" error and which ones are just "echo" errors. Sometimes a change that appears fairly modest might cause several real errors, thus leading to hundreds of echo errors and many hours or days of debugging.

IV. Component Revenue Requirements

Referring to Attachment 8, note that on the TOTAL layer, both revenues and expenses can be allocated to class. Therefore, the income statement can be processed for each class. I.e., all the expenses can be subtracted from revenue, in order to determine the net return. However, the same is not true on the 17 sublevels. Although costs and even Other Retail Revenue and Other Operating Revenue can be allocated to the sublevels, there is no way to directly allocate the Retail Revenue Requirement. Therefore, an indirect method must be used. First, the return amounts that have already been determined on the TOTAL layer are allocated to the sublevels using Rate Base. (This allocator is appropriate because return on investment is directly related to the investment itself, which is the Rate Base.) Thus for any given class column on any given sublevel, all values will be known except Retail Revenue Requirement. So algebra can be employed to convert the basic income statement formula (revenue minus expense equals return) into a more useful form (return plus expenses equals revenue). This can be informally referred to as the "backwards revenue calculation."

Because of the way income taxes are calculated, the backwards algebra is a bit complex. (Please see Attachment 9.) To make that process more understandable, it's helpful to break the calculation into three pieces. Using "T" as an abbreviation for the utility's corporate income tax percent, there is one block of numbers that has no tax adjustment, a second block that is multiplied by 1 / (1-T), and a third block that is multiplied by T / (1-T).

Most dollars are in the first block. That block includes all the non-tax expenses, as well as credits for Other Retail Revenue and Other Operating Revenue.

The 1 / (1-T) block consists of "grossed up" return. E.g., suppose $100 of return was needed. If the corporate tax rate were 40%, then $100 x 1 / (1 - .40), or $166.67 would need to be initially collected. After 40% was paid to income taxes, there would indeed be $100 left over.

The T / (1-T) block contains tax additions and deductions. E.g., book depreciation is an addition, while taxable depreciation is a deduction. If, as is normally the case, tax depreciation exceeded book depreciation, the net amount would be a tax credit. Suppose a net depreciation credit of $100 exists. Continuing the previous example, the $100 credit would avoid the tax payment of $66.67 out of the total $166.67. (And $100 x .40 / (1 - .40) does equal $66.67.) Therefore, the revenue requirement would only be $100. $100 x .40, or $40 would still go to income taxes, resulting in a preliminary net of $60. But because of the $100 depreciation tax credit, the utility could avoid writing the associated $40 tax check. That money could be added to the $60, providing a total of $100 to investors.

(Note that for accounting convenience, the 1 / (1-T) block grosses up all return revenue – not just return to shareholders (which really is taxable), but also debt (which is not taxable). However, since interest payments are tax deductible, the T / (1-T) block offsets the 1 / (1-T) impact on interest.)

V. Test Year Cost Development

The Company has a data gathering process that takes the following NSP (Minn) Company plant and plant-related data collected from the various departments and categorizes them into the functional use level of detail required for input into the CCOSS.

1. Electric Plant in Service (beginning and end of study period)
2. Accumulated provision for Depreciation of Plant in service (beginning and end of study period)
3. Accumulated Deferred Income Taxes (beginning and end of study period)
4. Construction Work in Progress
5. Book Depreciation
6. Property and Real Estate Taxes
7. Provision for Deferred Income Taxes
8. Investment Tax Credit: Flow-Through and Generated (this has been almost completely phased out)
9. Tax Deductions

In general, the system is developed from the computerized plant and depreciation records of the Company. The "plant in service" and "depreciation" expenses are identified by account and asset location numbers. Through the use of property aging records (age distributions of surviving plant in service by asset location) the remaining plant related items are developed from these account and asset location numbers. The input data that becomes available according to functional class total (such as production plant, transmission plant and distribution plant) and, in the case of budgeted data, according to funding project are prorated to the respective functional use designations through simulation processes giving effect to vintage distribution, appropriate depreciation methods, rates and procedures. This is accomplished in an automated mode by applying a series of allocation factors against plant data, the source information being supplied by various departments of the Company.

The balance of the plant and expense items in the cost study are functionalized primarily based upon projections of historical relationships and analyses and Federal Energy Regulatory Commission (FERC) or Company budgeting information. For example, operations and maintenance expenses are budgeted by JDE business unit, JDE object account and JDE subledger and mapped to FERC account for a test year cost study period.

Within the production function, the expenses of fuel, purchased power, and sales to non-associated utilities are obtained from the Company's electric production expense budget, interchange expense from the Company's Interchange Agreement between NSP's Minnesota and Wisconsin Companies, and other production expenses from the FERC budget. Transmission expense is determined by historical analysis and the FERC budget. Distribution O&M, customer accounting, customer service information, administrative and general definitions of expenses are determined from the FERC budget. Labor expenses also are captured from the FERC budget.

Other administrative and general O&M expenses such as property insurance, pensions and benefits, injuries and claims, rents and maintenance and regulatory expense are determined from the Company's budget.

Similarly, electric plant held for future use, unamortized rate case expense, fuel inventory, materials and supplies, prepayments, other operating revenues, extraordinary property losses and deferred costs charged to operating expenses are derived based upon the projection of historical cost relationships and corporate or FERC budgeting information.

Nuclear fuel consumed is determined from computer modeling of nuclear plant operations and the Company's production expense budget. Functionalization of Allowance for Funds Used During Construction (AFC) is developed in the FPIS.

The Company's test year costs explained above are entered into the Jurisdictional Cost of Service Study supported by the Company's Revenue Requirement Department. This study allocates or assigns the total Company costs to the appropriate jurisdiction. The resultant jurisdictional costs are entered into the CCOSS, which then allocates or assigns the jurisdictional costs to customer classes.

VI. FUNCTIONAL USE CATEGORIES BY FUNCTIONAL CLASS

Jurisdiction Functional Use

NOTE: Each of the following categories is applied to Minnesota, South Dakota, North Dakota and Wholesale jurisdictions.

Functional Class	Plant and Plant-Related Item Data	FERC Account
Production		310-346, 120.1 – 120.5
1. Fossil Plants	Steam	
2. Nuclear Plants	Nuclear Plant	
3. Other Plants	Other	
4. Hydro Plants	Hydro	
5. Nuclear Fuel	Nuclear Fuel	

Transmission 350-359

6. Transmission Lines: Transmission lines are classified as transmission based primarily on voltage level but also following the guidelines established in the Minnesota Cost Separation Filing (Docket No. E-999/CI-99-1261). The Minnesota Commission determined that the guidelines and principals established in the Cost Separation Filing were consistent with the FERC 7 Factor Test.

7. Transmission Substations: Substations are functionalized as generation step-up, transmission, or distribution based on the principals and guidelines established in the Minnesota Cost Separation Filing. The Minnesota Commission determined that the guidelines and principals established in the Cost Separation Filing were consistent with the FERC 7 Factor Test

Distribution 360-373

8. Distribution Substations: Substations are functionalized as generation step-up, transmission, or distribution based on the principals and guidelines established in the Minnesota Cost Separation Filing. The Minnesota Commission determined that the guidelines and principals established in the Cost Separation Filing were consistent with the FERC 7 Factor Test

9. Distribution Mass Property: Overhead Lines, Underground Lines, Transformers and Capacitors, Services, Meters, Installations on Customer Premises, Leased Property on Customer Premises, and Street Lighting

General 389-399

10. General - All Tools and Equipment, Supervision and Data Retrieval, Buildings and Furniture, Motor Vehicle & Data Processing, and Research and Development

Common 301, Portions of 389-398

11. Common - Other than Transportation & Data Processing; Motor Vehicle & Data Processing

VII. FUNCTIONAL USE CATEGORIES FOR TRANSMISSION PLANT AND DISTRIBUTION SUBSTATIONS AND PLANT RELATED ITEMS

(FERC ACCOUNT NO.S 360-363)

A. Generation Step-Up

1. Substation facilities at generating stations that are utilized to connect the generators to the transmission system (including step-up transformers).
2. Substation equipment necessary for the operation of the generation station.
3. Transmission investment between generator and plant substation bus.

B. Bulk Transmission

1. Transmission lines operating as part of a loop or grid. (This category includes all transmission lines even if the line is a radial line or tap serving only a distribution substation or serving a particular customer or class of customer (except leased facilities).
2. Transmission Substations - facilities operating as part of a loop or grid.
3. Distribution Substations - facilities operating as part of a loop or grid. (This category will not include facilities at distribution substations if such a facility is only a high side bus tie breaker(s) or switch(s) between two distribution transformers or if such a facility is a switch(s) installed solely because the distribution substation is located there.)
4. Capacitors installed on transmission lines or installed on the high voltage side of a substation power transformer.

B. Distribution (600v-13.8kV) (most 23kV-34.5kV)

1. Distribution facilities in distribution substations.
2. Distribution facilities in transmission substations.
3. Distribution lines from 600 volts to 13.8kv.
4. 23kV and 34.5kV lines which do not operate as part of a subnetwork but serve as distribution primary.
5. Capacitors installed on distribution lines.
6. Capacitors installed on the low-voltage side of the power transformer(s) at distribution substations.

C. Direct Assignment

1. Substations where the entire substation, or a substantial portion of the substation, is solely devoted to a particular customer (investments of less than $100,000 will not be considered.)
2. Distribution Substations - substations and low-voltage equipment that supply both NSP retail customers and also a wholesale customer(s). (A percentage of such facilities is directly assigned to the wholesale customers(s) based on peak demand.)

VIII. CLASSIFICATION OF DISTRIBUTION MASS PROPERTY PLANT FUNCTIONAL USE ACCOUNTS

Overhead Lines (FERC Account No. Is 364 & 365)

The assignment of overhead conductors and poles investment to primary and secondary voltage levels, and street and area lighting was accomplished through the use of industry adopted engineering estimates.

The customer and capacity component classification of the primary and secondary voltage functions were developed using the 'minimum size' method for determining customer/ capacity components of distribution facilities. This method is discussed in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC) in 1992.

Underground Lines (FERC Account No.'s 366 & 367)
The assignment of underground conductors and conduits investment to primary and secondary voltage levels was obtained from Company plant accounting records for underground cables and conduit (FERC Account No.'s 366 and 367).

The customer and capacity component classification of the primary and secondary voltage functions of these underground cables and conduits were developed using the 'minimum size, method for determining customer/capacity components of distribution facilities. This method is discussed in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC) in 1992.

Line Transformers (FERC Account No. 368)
The assignment of line transformer investment to primary and secondary voltage levels was based on weighting of historical plant accounting records of line transformers, vault transformers, pad mounted transformers, auto transformers, regulators, and capacitors. The investment in capacitors, regulators and auto transformers were assigned to the primary function and the balance of the account was assigned to the secondary function.

The secondary function was further divided into capacity and customer components. Vault transformers were assigned as 100% capacity while pad mounted and line transformers were separated between capacity and customer components on the basis of the minimum system concept as discussed under overhead and underground lines.

Services (FERC Account No. 369)
The Company maintains Account No. 369 for all overhead and underground services and the entire account was considered being related to the secondary function.

The division of overhead services into capacity and customer components was made based on a historical relationship using the minimum system concept discussed under overhead lines. Underground services were separated based on the same percentages developed for overhead services.

General Plant (FERC Account No- Is 389-399)
Facilities common to all electric functions (i.e. production, transmission, distribution)

Electric Common Plant (FERC Account No. Is 301, 389-399)
The electric portion of facilities common to both electric and gas utilities

IX. STRATIFICATION

Base Load/Peaking Stratification

Production plant investment is stratified (split) into two components: capacity-related (peaking) and energy-related (base load).

The method used to stratify production plant investment compares the average insurance replacement cost per MW of capacity of the various sources of capacity. These sources consist of nuclear, fossil steam, hydro, and gas turbine or diesel generation. The least expensive plant source, gas turbine or diesel peaking generation, is compared to the other sources. The percentage amount that peaking represents of other capacity sources is used to determine the peaking component of each capacity source.

This method recognizes the dual role of all capacity sources in supplying both energy and demand requirements. In other words, only that portion of a generating plant over the cost of a peaking plant is attributed to the energy-related (base load) function. This results in nuclear and fossil investment costs are stratified to both base load and peaking components. These plants provide inexpensive energy and, at the same time, contribute towards meeting the peak load requirements.

This stratification method splits production plant investment as follows:

Production Type	% Base Load	% Peaking
Hydro	72.0	28.0
Nuclear	81.4	18.6
Steam Fossil	67.3	32.7
Gas Turbine & Diesels	0.0	100.0

The stratification methodology is also applied to the demand-related expenses associated with purchased power agreements. Each purchased power agreement is analyzed as to which capacity source it most closely represents. These expenses are then stratified using the appropriate production type percentages noted above.

Summer Peaking/Winter Peaking Functional Use Categories

The capacity-related component of production plant investment is further separated into summer and winter seasonal costing periods. This separation recognizes the costs incurred by customers in relationship to their loads in these seasons. The portion of the capacity-related component dedicated to serving a seasonal function is computed by applying a seasonal demand-weighting factor to peaking plant investment. The weighting factor is derived from test year monthly system peak demands, which have been reduced by the annual average demand. The four summer months and eight winter months are specified and averaged to determine each season's portion of the averaged annual total.

The current factor used in the Class Cost Study weighs 74.97% of peaking investment to the summer period and 25.03% to the winter period.

X. ALLOCATOR DESCRIPTIONS

In the table below, the Code column contains the allocator codes actually listed in the CCOSS printout. The Description column mostly describes what the allocator is, and the Derivation column mostly describes how the allocator was created; however, there is some overlap between these two columns. The E/I column tells whether an allocator is external or internal. (An external allocator is one that was prepared outside of the CCOSS. An internal allocator is created within the CCOSS by combining the results of external allocators and / or other internal allocators.) The Components column indicate which billing component(s) and unbundled business unit(s) the allocator applies to. The letters in this column correspond to the codes shown in Attachment 7. Nearly every line of this table is a normal allocator that first spreads dollars to class and then spreads each class amount to billing and unbundled components. But a few of the "typed-in" revenue amounts, such as R01, only spread dollars to class. And there are also a pair of "column allocators" (BASE and R02). These allocators are only used after dollars have already been spread to class. Then they spread the results to the component column. Such two-stage allocations are indicated in the Alloc column of the CCOSS with a semi-colon (e.g., "R01;R02"). Please see Attachment 10 for an overview of the Company's electrical system and how the allocators fit into it.

Code	Allocator for:	Description	Derivation	E/I	Components
BASE (col)		Rate Base column allocator	Component allocators for each subclass add to 100%	Int	BSW-NF-T-UPC-VE
C10	Used to calculate C11	C11 less duplicate service customers	C11 less automatic protective lighting and load management customers	Ext	V
C11	Revenues from connection charges	Average monthly customers	Forecasted annual bills / 12	Ext	V
C11P10	Non CIP customer assistance exp, sales exp, and instructional advertising exp.	Average of customer percents and production plant percents	C11PI0 = (C11%+P10%)/2	Int	BSW-E
C11WA	Customer accounting expenses	Weighted customer accounting expenses	C11 X C11WAF	Ext	E
C11WAF	Used to calculate C11WA allocator	Customer accounting weighting factors	Accounting costs for a residential customer are set to 1.0. Other classes are defined relative to residential. E.g., if a class were three times costlier, its factor would be 3.0.	Ext	E
C12	Used to calculate C12WM allocator	C11 with adjusted street lighting customer count	Reflects actual number of meters	Ext	V
C12WM	Plant and expenses for Meters	Weighted meter investment	C12 X C12WMF	Ext	V
C12WMF	Used to calculate C112WM allocator	Average meter cost for each customer type		Ext	V
C61PS	The customer portion of primary distribution line plant	Average monthly customers served at primary or secondary voltage	C11 less transmission transformed and transmission voltage customers	Ext	V
C62NL	The customer portion of company owned services plant	Adjusted average monthly secondary voltage customers	C62Sec less street lighting and C&I underground customers	Ext	V

Code	Allocator for:	Description	Derivation	E/I	Components
C62Sec	The customer portion of secondary distribution plant	Average monthly customers served at secondary voltage	C61PS less primary voltage customers	Ext	V
D100E0	Economic development expenses	100 percent Production Level Demands and 0 percent Energy at Generation Level weighted by hourly price	D100E0 = (1.0000 x D10C)+(0.000 x E8760). The demand portion is further split between Summer and Winter based on D10C; the energy portion is already split between on-peak and off-peak because E8760 is split that way. Weighting based on economic development energy times any excess energy charge (Gen Svc secondary voltage energy – marginal energy cost) vs economic development demand times the average annual demand charge (Gen Svc secondary voltage demand, 4/12 summer and 8/12 winter)	Int	SW
D10C	Plant and expenses for power production, power purchases and generation step-up transformers that are "peaking" in nature	Weighted Average of Class Contributions to Summer and Winter Peaks - Production Level	Allocator equals (D10W% plus (D10S% times 2.995)) divided by (1 + 2.995); 2.995 is the ratio obtained by taking the average summer and winter system peaks, subtracting the average annual load and dividing the two results.	Int	SW
D10S	Peaking plant weighted by summer demand weighting factor	Class contribution to Summer System Peak, from 2008 Demand Study		Ext	S
D10T	Plant, depreciation, taxes and expenses for transmission	Weighted Average of Class Contributions to Summer and Winter Peaks - Transmission Level	Allocator equals (D10W% plus (D10S% times 1.2979)) divided by (1 + 1.2979); 1.2979 is the ratio of the average summer and winter system peaks.	Ext	T
D10W	Peaking plant weighted by winter demand weighting factor	Class contribution to Winter System Peak, from 2008 Demand Study		Ext	W
D60Sub	Distribution substation plant, depreciation and taxes	Class-coincident peak less transmission-level demand		Ext	U
D48E52	CIP expenses (Not applicable to South Dakota)	48 percent Production Level Demands and 52 percent Energy at Generation Level weighted by hourly price	D48E52 = (.4776 x D10C)+(.5224 x E8760). The demand portion is further split between Summer and Winter based on D10C; the energy portion is already split between on-peak and off-peak because E8760 is split that way. Weighting is based on a CIP allocation of program costs.	Int	SW-NF

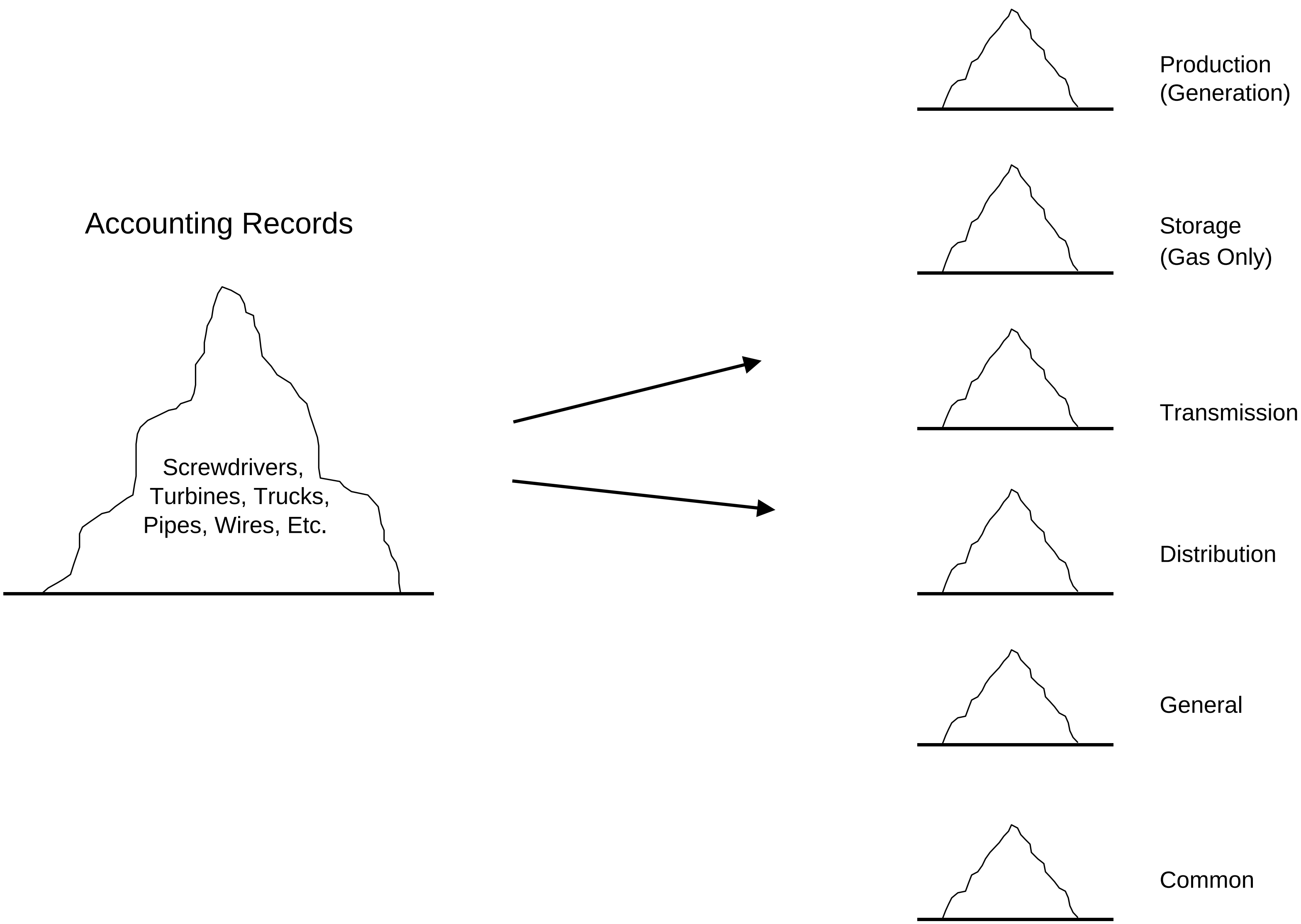
Code	Allocator for:	Description	Derivation	E/I	Components
D61PS	The capacity portion of primary distribution plant	Class-coincident peak for primary and secondary voltage customers	D60Sub less transmission transformed demands and customer demand served by minimum distribution system, with reduced Residential With Space Heating demand to reflect that their summer peak is less than their winter peak	Ext	P
D62NLL	The capacity portion of company owned services	Secondary voltage demand less lighting	Non-coincident (or "customer peak") demand for secondary voltage customers, less the following: street lighting, area lighting and C&I customers served underground	Ext	C
D62SecL	The capacity portion of secondary distribution plant	Average of class-coincident peak, secondary voltage percents and non-coincident secondary voltage percents	First define D62Sec as equal to D61PS, less primary customers. Then for each secondary class, D62SecL equals the average of D62Sec percent and non-coincident (or "customer peak"), secondary voltage percent.	Ext	C
D8760	Base load and nuclear fuel and generation step-up plant and expenses	E8760, but treated as a demand allocator		Ext	B
DASL	Street lighting plant	Street lighting demands for overhead lines	Split further among company-owned, customer-owned and area protective lighting	Ext	V
Dir Assign		A direct assignment of costs or revenues to a specific class or classes.		Ext	Various
E10	Not used as an allocator	Energy (MWH) at Generation Level (only used for the preparation of E20)	Budgeted class sales at the meter, divided by class loss factor, to get sales at the generator	Ext	NF
E11	Not used as an allocator	Class annual on-peak percentages	Load Research department	Ext	N
E20	Not used as an allocator	Energy (MWH) at generation, with annual on-peak sales weighted to reflect higher on-peak fuel costs (This method was used in 1993 and was reviewed as an option for this case.)	E20 = On-Peak + Off-Peak, where On-Peak = E10 X E11 X 1.752 and Off- Peak = E10 X (1-E11). Note: 1.752 = ratio of on-peak to off-peak annual marginal energy costs	Ext	NF
E8760	Revenues from sales that are energy related, fuel, purchased power and production expenses that are energy related.	Energy (MWH) at generation, with hourly on-peak sales weighted to reflect higher on-peak fuel costs	The hourly on-peak sales ratio for each class is weighted by the hourly marginal energy cost. (In 2008 there were 8,784 hours in the year.)	Ext	NF

Code	Allocator for:	Description	Derivation	E/I	Components
LABOR(S)	Misc plant and expenses that are general in nature	LABOR (and LABORS) reflect total labor costs on page 12	LABORS equals all labor costs except Admin and General. But LABORS is then used to allocate Admin and General, and the result is added to LABORS to derive LABOR. Thus the two allocators are actually identical.	Int	BSW-NF-T-UPC-VE
NEPIS	Tax benefit transfer related items	Net Electric Plant in Service	Electric plant in service less accumulated provision for depreciation (Line 27 of page 5)	Int	BSW-T-UPC-V
ORDREV		Typed-in Ordered Revenues	PROREV is used for the Proposed CCOSS; ORDER is used for the Ordered CCOSS	Ext	BSW-NF-T-UPC-VE
OXDTS	Selected distribution expenses	All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous	Lines 2 thru 7, 9 and 11 of page 8. Note: Supervision & Engineering must be excluded to avoid an infinite loop in the spreadsheet.	Int	BSW-T-UPC-V
OXOPD	Used in labor allocator calculations	Other Production: Total Capacity costs	Other Prod: Peaking + Base Load (line 39 of page 7)	Int	BSW
OXTS	Selected distribution and administrative and general expenses	Relevant O&M costs	All O&M costs except Regulatory Expense and any A&G costs that will be allocated on OXTS (lines 42 & 43 of page 7 and lines 12-15, 18-21, 32 and 33 of page 8,	Int	BSW-NF-T-UPC-VE
P10	Selected production plant and power purchases	Production Plant	Total production costs , on line 6 of page 4	Int	BSW
P5161A	Used in labor allocator calculations	Total Generation Set-Up	Tran Gener Step Up (line 9 of page 4) + Distrib Substn Step Up (line 14 of page 4)	Int	BSW
P61	Substation expenses	Distribution Plant: Substations	Substations (line 18, page 4)	Int	BSW-T-U
P68	Expenses for line transformers	Distribution Plant: Line Transformers	Primary & secondary; capacity & customer (line 37 of page 4)	Int	PC-V
P69	Depreciation and taxes for services	Distribution Plant: Services	Secondary; capacity & customer (line 40 of page 4)	Int	C-V
P73	Depreciation and taxes for street lights	Typed-in Street Lighting	Line 42 of page 4	Ext	V
POL	Expenses, depreciation and taxes for overhead lines	Distribution Plant: Overhead Lines	Primary, secondary & street lighting; capacity & customer (line 26 of page 4)	Int	PC-V
PROREV		Typed-in Proposed Revenues	PROREV is used for the Proposed CCOSS; ORDER is used for the Ordered CCOSS	Ext	BSW-NF-T-UPC-VE
PT0	Working cash	Total Real Estate & Property Taxes	Line 50 of page 9	Int	BSW-T-UPC-V

Code	Allocator for:	Description	Derivation	E/I	Components
PTD	Plant, depreciation and taxes for general plant and electric common plant	Production + Transmission + Distribution Plant	Lines 6, 13 and 43 of page 4	Int	BSW-T-UPC-V
PUL	Expenses, depreciation and taxes for underground lines	Distribution Plant: Underground Lines	Primary & secondary; capacity & customer (line 33 of page 4)	Int	PC-V
R01		Typed in Present Revenues	Revenues generated from present rate design	Ext	BSW-NF-T-UPC-VE
R02 (col)	Selected revenues	All pre-tax operating expenses except for items allocated to component by R02	Component allocators for each subclass add to 100%	Int	BSW-NF-T-UPC-VE
R16C	Late pay charges	Typed-in Late Pay Charges		Ext	BSW-NF-T-UPC-VE
R16D	Selected revenues	Typed-in Present Misc Service Charges		Ext	V
R16DD	Selected revenues	Typed-in Proposed Increased Misc Svc Charges		Ext	V
RTBASE	Avoided tax interest	Total Rate Base (see also “BASE”)	Line 36 of page 6	Int	BSW-NF-T-UPC-VE
STRATH	Plant, depreciation and taxes for distribution step-up transformers	Production plant stratification study, for hydro		Ext	BSW
TD	Transmission and distribution materials and supplies	Transmission + Distribution	Lines 13 and 43 of page 4	Int	BSW-T-UPC-V
ZDTS	Supervision and engineering distribution expense	All Labor Distribution expense except Supervision and Engineering	Lines 34 thru 39, 41 and 42 on page 12.	Int	BSW-T-UPC-V

Plant Functionalization

By FERC Category



Rate Case - Cost Information Flow

Functionalized Accounting Costs

Desc	Costs
Produc	
Summ Pk	100
Winter Pk	200
Base	300
Total	600
Trans	
Step Up	
Bulk	
Direct	
Total	
Distrib	
Subs	
Overhead	

JCOSS

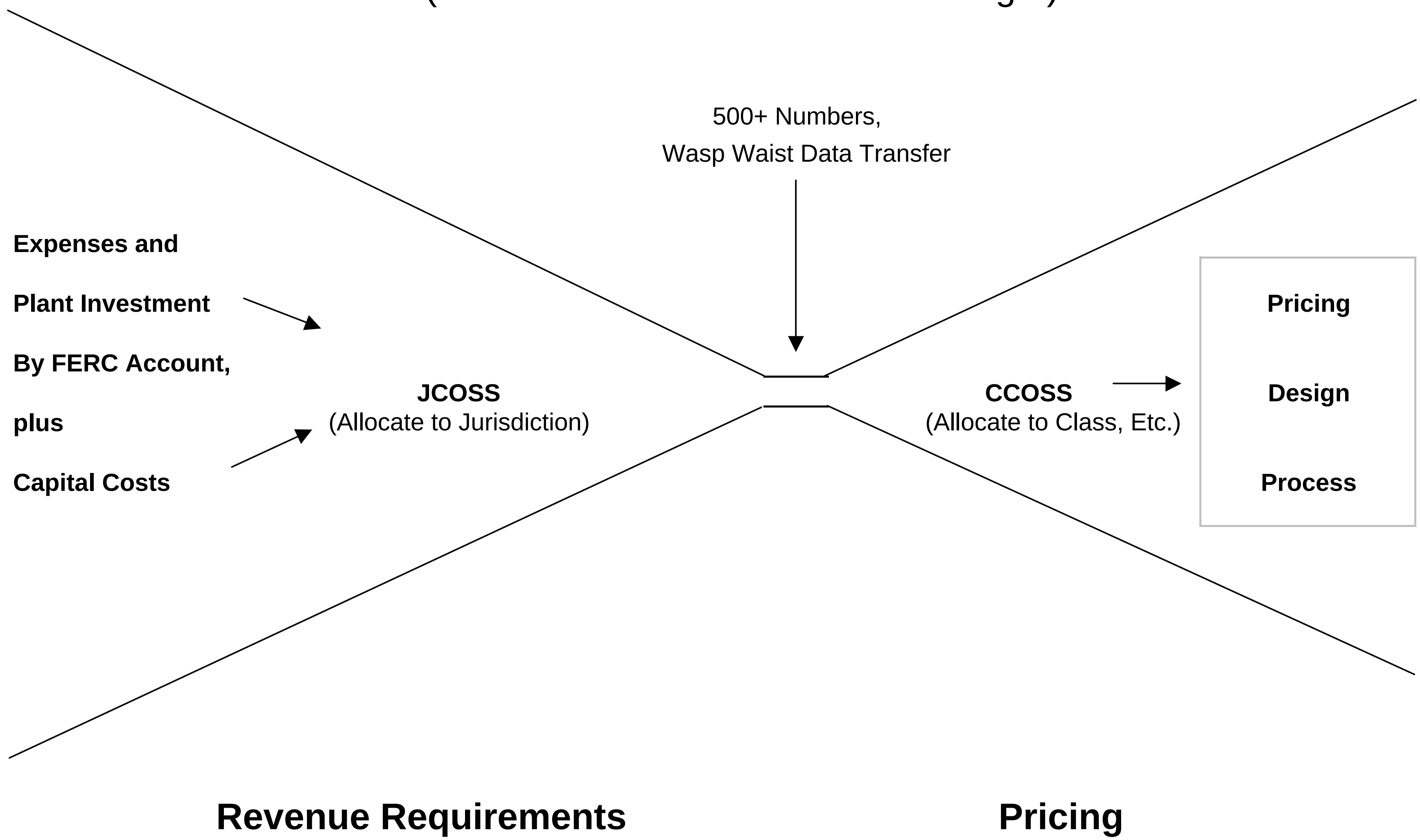
Desc	Alloc	Total	Mn	ND	SD
Produc					
Summ Pk	D10	100	70	20	10
Winter Pk	D15	200	150	30	20
Base	D20	300	170	40	90
Total		600	390	90	120
Trans					
Step Up					
Bulk					
Direct					
Total					
Distrib					
Subs					
Overhead					

CCOSS

Desc	Alloc	Mn	Res W/	Res W/o	(Other) (Classes)
Produc					
Summ Pk	D10S	70	2	11	….
Winter Pk	D10W	150	5	28	….
Base	D8760	170	22	33	….
Total		390	29	72	….
Trans					
Step Up					
Bulk					
Direct					
Total					
Distrib					
Subs					
Overhead					

Regulated Cost Allocation and Pricing Process

(Information Flows From Left To Right)



CCOSS Overview

In a rate case, a utility is allowed to recover all approved expenses, plus a reaonable return on net investment.

RATE BASE (Balance Sheet)

Original Plant in Service
- Accum Depreciation
+ & - Misc. Adjustments
Rate Base

INCOME STATEMENT

Revenue
- Oper & Maint Expen
- Bk Deprec, Prop Tax, Etc.
- Income Tax
Return $

Return $ / Rate Base = % Return

CCOSS - Top View

Detail of the 16 Print Pages

Summary	
Rate Base; Income Statement (Pres vs Prop/Ord Return)	1
Equal Return Rev Components	2
Prop/Order Return Rev Components	3

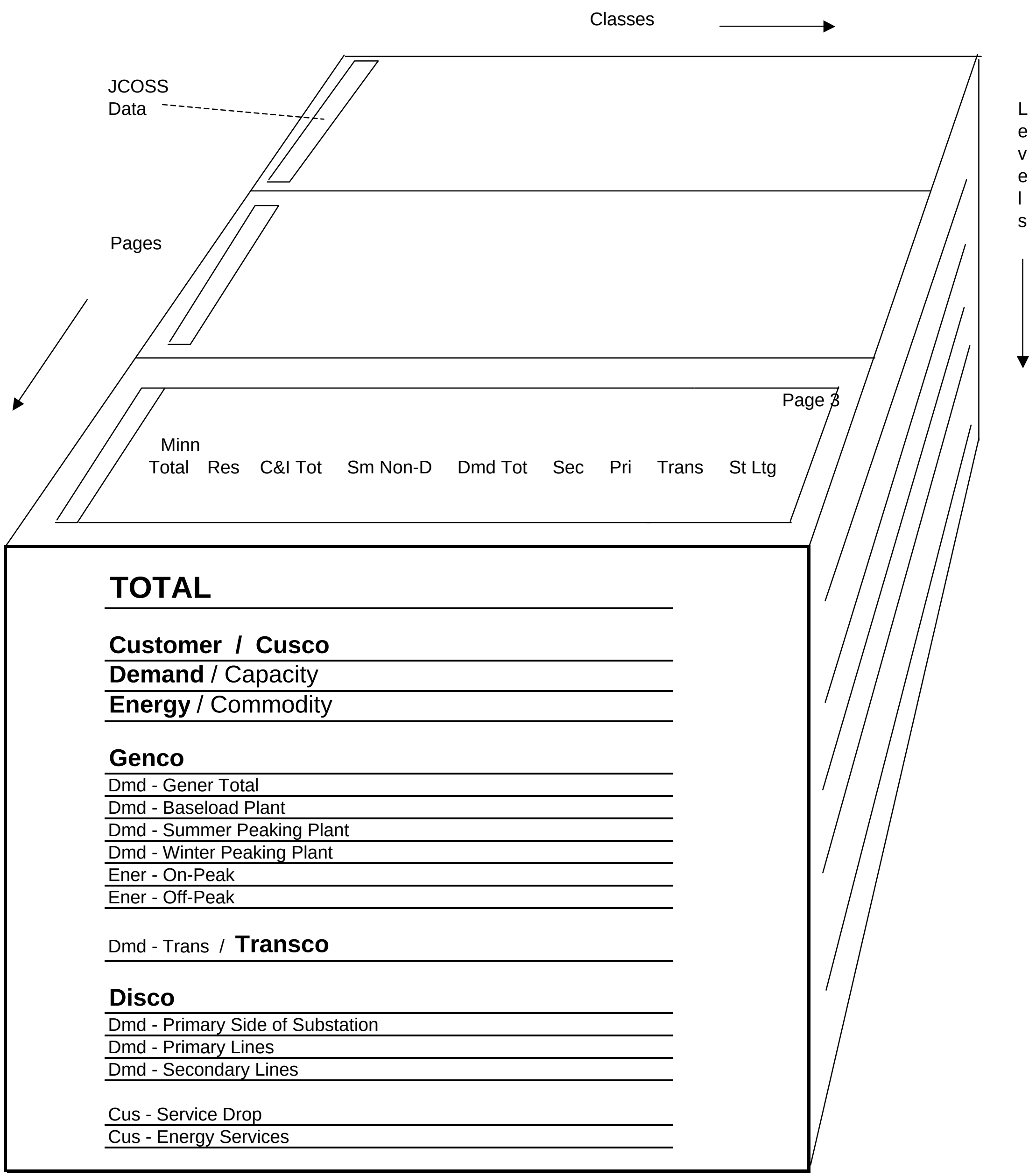
Rate Base	
Original Plant in Service	4
- Accumulated Depreciation - Subtractions (Accum Deferred Income Tax)	5
+ Additions (Construction Work in Progress & Misc) Rate Base	6

Income Stmt	
Present & Proposed/Ordered Revenue - O&M (Production, Transmission) [Pg 1 of 2]	7
- O&M (Distributiono & Misc) [Pg 2 of 2]	8
- Book Depreciation - Property Taxes	9
- Prov For Defer IT - Current Inv Tax Credit = Oper Inc Before Inc Tax	10
Tax Depreciation + And - Adjustments ===> Income Tax Oper Inc - Inc Tax = Pres & Prop/Order Return	11

Misc Calcs	
Allow For Funds Used During Construction Labor Allocator	12
Pres, Prop/Ord & Equal Rev Components	13

Allocators	
Internal Allocators	14
External Allocators	15
Constants	16

CCOSS - 3-D View

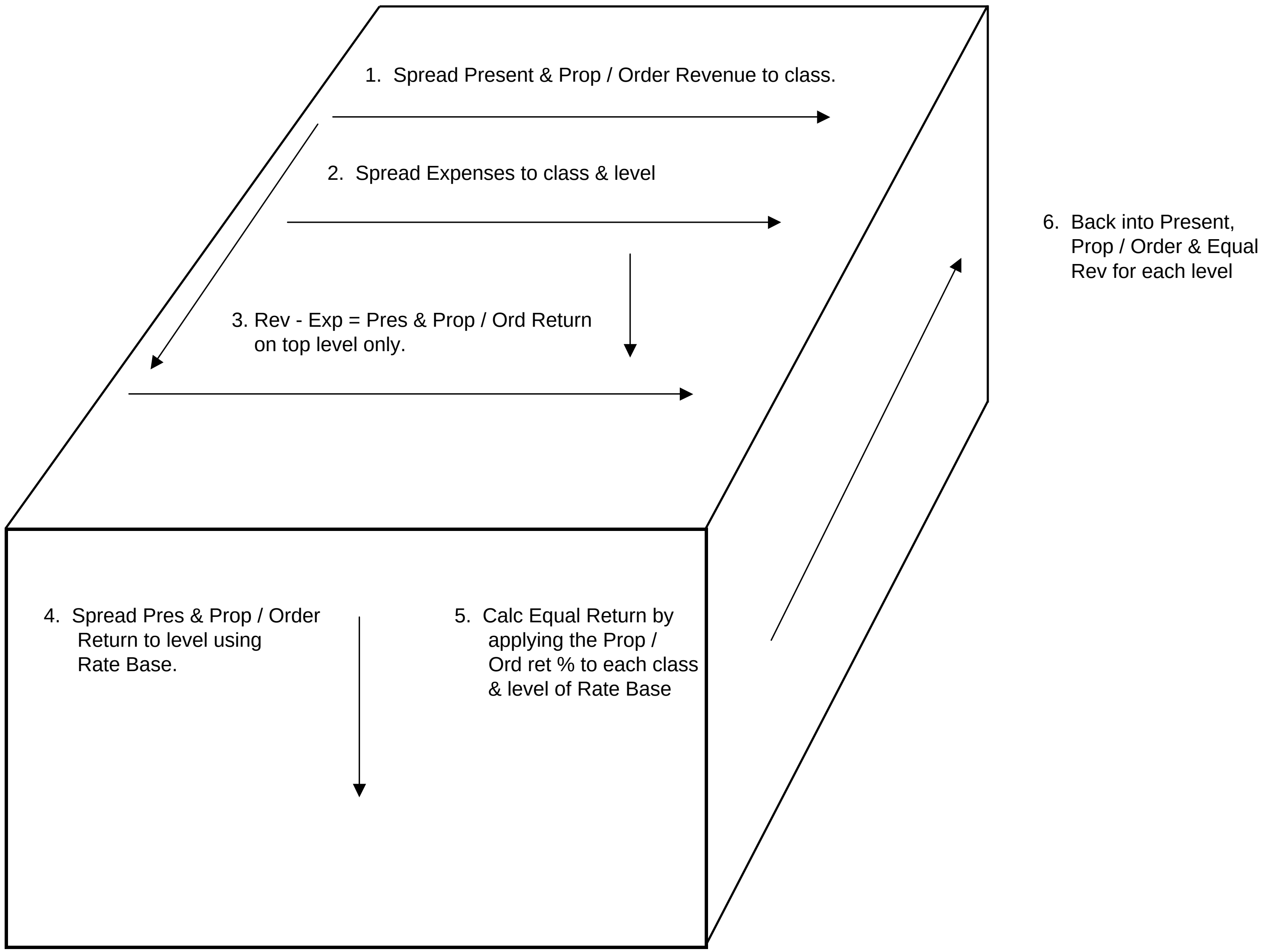


Unbundled CCOSS Totaling Rules

Billing Components

	Unbundled Business Units			
Total	**Genco**	**Transco**	**Disco**	**Cusco**
Customer				Service Drops (**V**) Energy Svcs (**E**)
Demand	(Gen Demd) Baseload Plant (**B**) Summer Peak Plant (**S**) Winter Peak Plant (**W**)	Transmission (**T**)	Substation (**U**) Primary Lines (**P**) Secondary Lines (**C**)	
Energy	On-Peak Energy (**N**) Off-Peak Energy (**F**)			

CCOSS - Backwards Rev Calc



Backward Retail Revenue Requirement

Backwards Revenue Formula

Retail Rev Reqt = Expenses (including Other Op Rev credit)
+ (Return on Equity x Rate Base) x 1 / (1-T)
+ (Tax Additions - Tax Subtractions) x T / (1-T)
- AFUDC

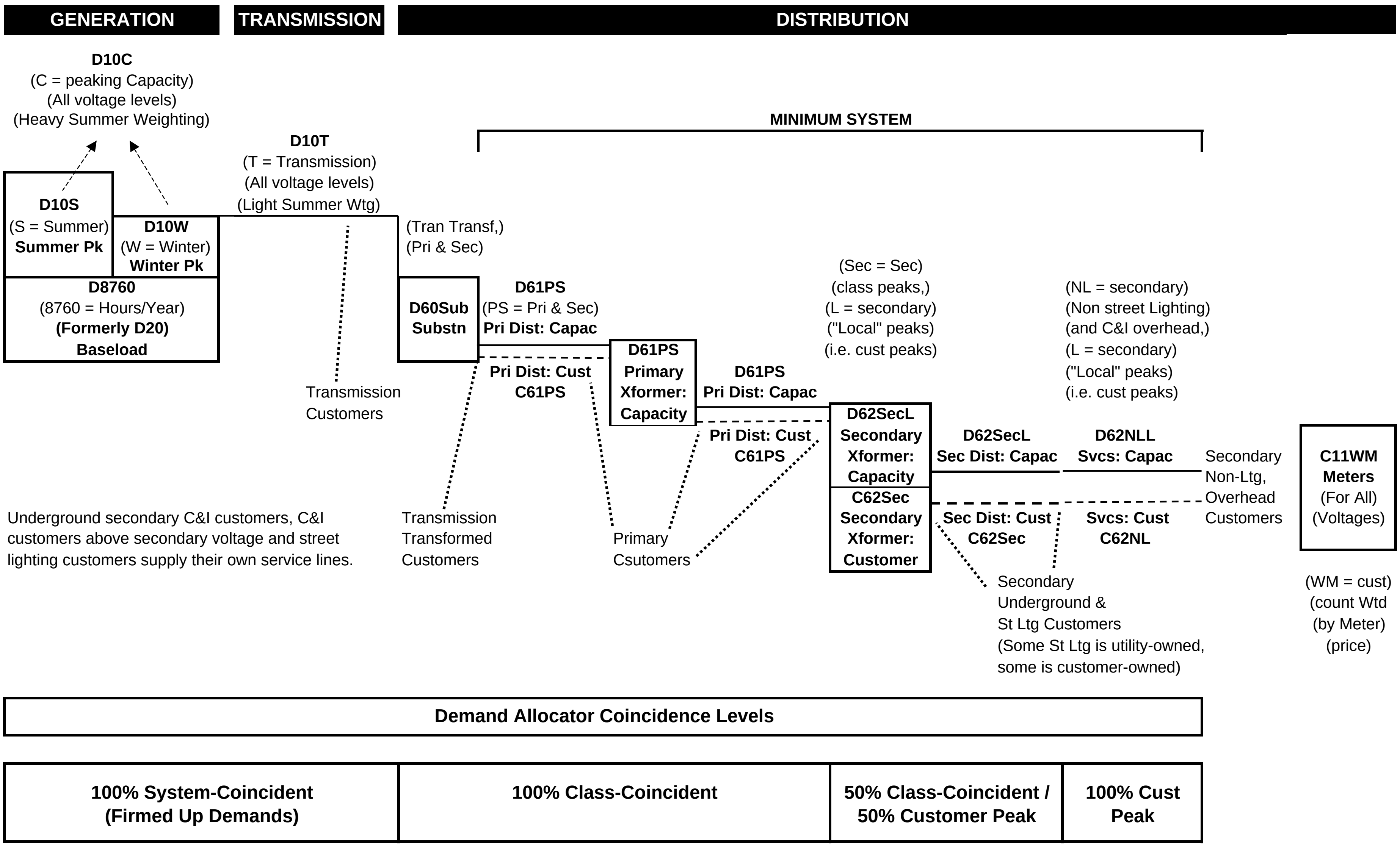
Expenses = Oper&Maint + Book Deprec + Rl Est & Property Tax + Payroll Taxes + Prov For Defer Inc Tax + Net Investment Tax Credit - Other Retail Revenue - Other Operating Revenue

Tax Additions = Book Deprecitaion + Deferred Inc Tax + Net Inv Tax Credit + Other Misc Expenses

Tax Subtractions = Tax Depreciation + Interest Expense + Other Tax Timing Differences

ELECTRIC SYSTEM ALLOCATORS

Height on the page roughly equates to voltage level



Northern States Power Company, a Minnesota Corporation | **Docket No. EL09-____**
Electric Utility - South Dakota | **Exhibit No. _____(MAP-1)**
Pro forma Year | **Schedule 4**
Summary of Class Cost of Service Study Results ($000) - Comparison Customer Classes | **Page 1 of 1**

UNADJUSTED REVENUE REQUIREMENTS

			Residential					Small C&I				Large C&I				
		MN	Res Tot	Res W/	Res W/o	Ld Mgmt	C&I Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Interrupt	Ltg Tot
1	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 2)	164,855	67,137	3,438	63,473	227	96,055	62,849	9,557	52,064	1,228	33,206	6,145	13,135	13,926	1,663
2	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	111	44	2	42	0	66	44	6	37	1	21	4	9	9	1
3	Unadjusted Operating Revenues (line 2 + line 3)	164,966	67,182	3,440	63,515	227	96,120	62,893	9,563	52,100	1,229	33,228	6,149	13,144	13,935	1,664
4	Present Rates (CCOSS page 2, line 3)	146,384	58,464	3,090	55,217	157	86,541	58,174	8,446	48,422	1,306	28,367	5,108	12,035	11,224	1,379
5	Unadjusted Deficiency (line 3 - line 4)	18,582	8,718	350	8,298	70	9,579	4,719	1,117	3,678	(77)	4,861	1,041	1,109	2,711	285
6	Defic / Pres (line 5 / line 4)	12.7%	14.9%	11.3%	15.0%	44.5%	11.1%	8.1%	13.2%	7.6%	-5.9%	17.1%	20.4%	9.2%	24.2%	20.6%
7	**Ratio: Class % / Total %**	**1.00**	**1.17**	**0.89**	**1.18**	**3.51**	**0.87**	**0.64**	**1.04**	**0.60**	**-0.47**	**1.35**	**1.60**	**0.73**	**1.90**	**1.63**

INTERRUPTION REVENUE DISCOUNTS Vs INTERRUPTION CAPACITY COSTS

			Residential					Small C&I				Large C&I				
		MN	Res Tot	Res W/	Res W/o	Ld Mgmt	C&I Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Interrupt	Ltg Tot
8	Interruption Rate Discounts (CCOSS page 2, line 6)	2,128	728	23	644	61	1,400	111	2	108	1	1,289	0	0	1,289	0
9	Interruption Capacity Costs (CCOSS page 2, line 7)	2,128	820	32	784	4	1,302	863	117	730	17	439	81	165	193	5
10	Revenue Requirement Shift (line 9 - line 8)	0	92	9	140	(57)	(98)	752	115	622	16	(850)	81	165	(1,096)	5

ADJUSTED REVENUE REQUIREMENTS

			Residential					Small C&I				Large C&I				
		MN	Res Tot	Res W/	Res W/o	Ld Mgmt	C&I Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Interrupt	Ltg Tot
11	Adjusted Rate Revenue Reqt (line 1 + line 10)	164,855	67,230	3,447	63,613	169	95,957	63,601	9,672	52,685	1,244	32,356	6,226	13,300	12,830	1,668
12	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	111	44	2	42	0	66	44	6	37	1	21	4	9	9	1
13	Adjusted Operating Revenues (line 11 + line 12)	164,966	67,274	3,449	63,655	170	96,023	63,645	9,678	52,722	1,245	32,378	6,230	13,309	12,839	1,669
14	Present Rates (line 4)	146,384	58,464	3,090	55,217	157	86,541	58,174	8,446	48,422	1,306	28,367	5,108	12,035	11,224	1,379
15	Adjusted Deficiency (line 13 - line 14)	18,582	8,810	359	8,438	13	9,482	5,471	1,232	4,300	(61)	4,011	1,122	1,274	1,615	290
16	Defic / Adj Pres (line 15 / line 14)	12.7%	15.1%	11.6%	15.3%	8.0%	11.0%	9.4%	14.6%	8.9%	-4.7%	14.1%	22.0%	10.6%	14.4%	21.0%
17	**Ratio: Class % / Total %**	**1.00**	**1.19**	**0.92**	**1.20**	**0.63**	**0.86**	**0.74**	**1.15**	**0.70**	**-0.37**	**1.11**	**1.73**	**0.83**	**1.13**	**1.66**

PROPOSED REVENUE REQUIREMENTS

			Residential					Small C&I				Large C&I				
		MN	Res Tot	Res W/	Res W/o	Ld Mgmt	C&I Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Interrupt	Ltg Tot
18	Proposed Rates (CCOSS page 3, line 3)	164,856	66,875	3,464	63,227	184	96,405	64,962	9,628	53,879	1,455	31,443	5,646	13,221	12,576	1,576
19	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21+ line 23)	111	44	2	42	0	66	44	6	37	1	21	4	9	9	1
20	Proposed Operating Revenues (line 18 + line 19)	164,967	66,919	3,466	63,269	184	96,471	65,006	9,634	53,916	1,456	31,464	5,650	13,230	12,585	1,577
21	Proposed Increase (line 20 - line 14)	18,583	8,455	376	8,052	27	9,930	6,832	1,188	5,494	150	3,097	542	1,195	1,361	198
22	Difference / Pres (line 21 / line 14)	12.7%	14.5%	12.2%	14.6%	17.3%	11.5%	11.7%	14.1%	11.3%	11.5%	10.9%	10.6%	9.9%	12.1%	14.4%
23	**Ratio: Class % / Total %**	**1.00**	**1.14**	**0.96**	**1.15**	**1.36**	**0.90**	**0.93**	**1.11**	**0.89**	**0.90**	**0.86**	**0.84**	**0.78**	**0.95**	**1.13**

Rate Base

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential						Small Comm & Indus				Large Comm & Indus		
	Plant In Service	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Production		342,823	120,110	6,311	113,295	504	221,131	142,485	18,191	121,414	2,879	78,647	14,421	31,535	32,691	1,581
2	Transmission		82,287	32,733	1,647	30,942	144	49,196	32,441	4,263	27,525	653	16,755	3,105	6,341	7,308	357
3	Distribution		175,072	113,329	4,830	108,316	182	57,450	42,411	12,032	29,819	560	15,039	3,225	4,420	7,394	4,293
4	General		13,997	6,208	298	5,890	19	7,644	5,069	804	4,169	95	2,576	484	986	1,105	145
5	Common		21,141	9,376	450	8,896	29	11,546	7,656	1,215	6,297	144	3,890	731	1,490	1,669	219
6	TBT Invest		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total		635,319	281,755	13,536	267,339	880	346,968	230,061	36,505	189,224	4,331	116,907	21,967	44,773	50,167	6,596
	Depreciation Reserve																
8	Production		204,648	73,664	3,585	69,765	315	130,159	84,503	10,958	71,843	1,701	45,656	8,389	18,010	19,257	826
9	Transmission		26,967	10,709	538	10,124	47	16,141	10,642	1,398	9,029	214	5,500	1,019	2,083	2,397	117
10	Distribution		65,647	42,128	1,766	40,298	64	20,908	15,355	4,181	10,991	183	5,553	1,199	1,667	2,688	2,611
11	General		5,136	2,278	109	2,161	7	2,805	1,860	295	1,530	35	945	178	362	406	53
12	Common		11,690	5,184	249	4,919	16	6,384	4,233	672	3,482	80	2,151	404	824	923	121
13	Total		314,088	133,963	6,247	127,266	449	176,397	116,592	17,504	96,875	2,214	59,805	11,188	22,946	25,671	3,728
14	**Net Plant In Service**		321,232	147,792	7,289	140,073	430	170,571	113,469	19,002	92,349	2,118	57,102	10,779	21,827	24,497	2,868
	Deductions																
15	Accum Defer Inc Tax		55,794	27,239	1,262	25,901	76	28,326	19,094	3,328	15,421	344	9,232	1,765	3,425	4,043	229
	Additions																
16	Constr Work In Progress		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Fuel Inventory		5,879	1,975	116	1,851	8	3,871	2,467	308	2,109	50	1,404	257	576	572	32
18	Materials & Supplies		4,944	1,922	97	1,818	7	2,987	1,946	271	1,636	38	1,041	193	411	438	35
19	Prepayments		7,149	3,289	162	3,117	10	3,796	2,525	423	2,055	47	1,271	240	486	545	64
20	Non-Plant Assets & Liab		(2,637)	(1,109)	(53)	(1,052)	(4)	(1,492)	(987)	(161)	(806)	(19)	(506)	(93)	(197)	(215)	(36)
21	Working Cash		1,866	837	40	795	3	1,008	674	111	550	13	334	63	126	145	21
22	Total		17,201	6,915	362	6,530	24	10,171	6,626	952	5,545	129	3,545	659	1,401	1,485	115
23	**Rate Base**		282,639	127,469	6,389	120,702	378	152,416	101,001	16,626	82,473	1,903	51,415	9,673	19,803	21,939	2,754

Income Statement

			MN	Res Tot	Res W/	Res W/o	Ld Mgmt	C&I Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Interrupt	Ltg Tot
24A	**Tot Oper Rev - Pres**		181,317	70,871	3,776	66,887	208	108,873	72,541	10,289	60,656	1,596	36,332	6,569	15,247	14,516	1,572
24B	**Tot Oper Rev - Prop**		199,900	79,327	4,153	74,939	235	118,803	79,373	11,477	66,150	1,746	39,430	7,111	16,442	15,877	1,770
25	Oper & Maint		137,588	51,599	2,761	48,647	192	84,799	54,905	7,733	46,078	1,094	29,895	5,486	12,036	12,372	1,190
26	Book Depr + IRS Int		21,470	9,488	451	9,007	30	11,714	7,775	1,254	6,371	150	3,939	738	1,503	1,698	268
27	Payroll Tax		1,452	610	29	579	2	822	543	89	444	11	278	51	109	118	20
28	Real Est & Prop Tax		4,956	2,224	106	2,110	7	2,678	1,791	296	1,461	34	887	168	335	384	54
29	Deferred Inc Taxes		4,819	1,934	89	1,838	7	2,859	1,895	277	1,582	36	964	180	370	414	25
30A	Present Income Tax		(2,384)	(689)	6	(671)	(24)	(1,642)	(329)	(128)	(268)	67	(1,313)	(300)	(183)	(829)	(53)
30B	Proposed Income Tax		4,120	2,153	121	2,040	(8)	1,942	1,900	280	1,526	94	42	(42)	244	(160)	25
31	Allow Funds Dur Const		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32A	**Present Return**		13,416	5,704	334	5,378	(7)	7,643	5,962	769	4,988	205	1,682	245	1,077	359	68
32B	**Proposed Return**		25,495	11,317	594	10,718	5	13,989	10,564	1,549	8,688	328	3,425	529	1,845	1,050	189
33A	**Pres Ret on Rt Base**		4.75%	4.48%	5.23%	4.46%	-1.87%	5.01%	5.90%	4.62%	6.05%	10.77%	3.27%	2.54%	5.44%	1.64%	2.47%
33B	**Prop Ret on Rt Base**		9.02%	8.88%	9.31%	8.88%	1.23%	9.18%	10.46%	9.31%	10.53%	17.23%	6.66%	5.47%	9.32%	4.79%	6.85%
34A	**Pres Ret on Common**		2.98%	2.45%	3.91%	2.41%	-9.85%	3.50%	5.22%	2.74%	5.50%	14.64%	0.12%	-1.31%	4.32%	-3.05%	-1.43%
34B	**Prop Ret on Common**		11.25%	10.98%	11.81%	10.98%	-3.84%	11.56%	14.04%	11.82%	14.19%	27.16%	6.68%	4.38%	11.83%	3.05%	7.06%

PRES vs Equal Rev Reqts

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential						Small Comm & Indus				Large Comm & Indus		
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	**Equal Return On Rate Base**		**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**	**9.02%**
2	**UnAdj Equalized Rev Reqt**		**164,855**	**67,137**	**3,438**	**63,473**	**227**	**96,055**	**62,849**	**9,557**	**52,064**	**1,228**	**33,206**	**6,145**	**13,135**	**13,926**	**1,663**
3	**UnAdj Present Revenue**		**146,384**	**58,464**	**3,090**	**55,217**	**157**	**86,541**	**58,174**	**8,446**	**48,422**	**1,306**	**28,367**	**5,108**	**12,035**	**11,224**	**1,379**
4	**UnAdj Revenue Deficiency**		**18,471**	**8,673**	**348**	**8,256**	**70**	**9,514**	**4,675**	**1,111**	**3,642**	**(78)**	**4,839**	**1,037**	**1,100**	**2,702**	**284**
5	**UnAdj Deficiency / Present**		**12.62%**	**14.84%**	**11.25%**	**14.95%**	**44.45%**	**10.99%**	**8.04%**	**13.15%**	**7.52%**	**-5.98%**	**17.06%**	**20.30%**	**9.14%**	**24.07%**	**20.57%**
6	**Interruption Rate Discounts**		**2,128**	**728**	**23**	**644**	**61**	**1,400**	**111**	**2**	**108**	**1**	**1,289**	**0**	**0**	**1,289**	**0**
7	**Interruptible Capacity Costs**	D10C	**2,128**	**820**	**32**	**784**	**4**	**1,302**	**863**	**117**	**730**	**17**	**439**	**81**	**165**	**193**	**5**
8	**Revenue Shift**		**0**	**92**	**9**	**140**	**(57)**	**(98)**	**752**	**115**	**622**	**16**	**(850)**	**81**	**165**	**(1,096)**	**5**
9	**Adj Equal Rev Reqt (Rows 2+8)**		**164,855**	**67,230**	**3,447**	**63,613**	**169**	**95,957**	**63,601**	**9,672**	**52,685**	**1,244**	**32,356**	**6,226**	**13,300**	**12,830**	**1,668**
10	**Pres Rev (Row 3)**		**146,384**	**58,464**	**3,090**	**55,217**	**157**	**86,541**	**58,174**	**8,446**	**48,422**	**1,306**	**28,367**	**5,108**	**12,035**	**11,224**	**1,379**
11	**Adj Revenue Deficiency**		**18,471**	**8,766**	**357**	**8,396**	**12**	**9,416**	**5,427**	**1,226**	**4,263**	**(62)**	**3,989**	**1,118**	**1,265**	**1,606**	**289**
12	**Adj Deficiency / Adj Present**		**12.62%**	**14.99%**	**11.55%**	**15.21%**	**7.92%**	**10.88%**	**9.33%**	**14.51%**	**8.80%**	**-4.74%**	**14.06%**	**21.89%**	**10.51%**	**14.31%**	**20.96%**
	Customer Component																
13	Min Sys & Service Drop		13,922	11,112	438	10,669	5	1,963	1,873	1,329	507	37	91	(1)	(1)	93	846
14	Energy Services		4,947	3,954	156	3,794	5	950	918	599	314	5	32	1	1	29	43
15	Total Customer **(Cusco)**		18,869	15,067	594	14,463	10	2,913	2,791	1,928	821	42	123	1	(1)	122	889
16	Ave Monthly Customers		82,176	70,041	2,757	67,120	164	10,182	10,060	7,167	2,845	48	122	9	5	108	1,954
17	Svc Drop Reqt	$ / Mo / Cust	$14.12	$13.22	$13.23	$13.25	$2.62	$16.07	$15.51	$15.46	$14.84	$64.38	$62.04	($5.11)	($23.56)	$71.59	$36.08
18	Ener Svcs Reqt	$ / Mo / Cust	$5.02	$4.70	$4.71	$4.71	$2.46	$7.77	$7.61	$6.96	$9.21	$9.21	$21.68	$13.71	$13.71	$22.70	$1.83
19	Total Reqt	$ / Mo / Cust	$19.13	$17.93	$17.95	$17.96	$5.08	$23.85	$23.12	$22.42	$24.05	$73.59	$83.72	$8.59	($9.85)	$94.29	$37.91
	Energy Component																
20	On Peak Rev Reqt		41,934	13,208	751	12,401	55	28,623	18,539	2,394	15,777	369	10,084	1,844	4,005	4,235	104
21	Off Peak Rev Reqt		34,358	12,426	755	11,622	49	21,618	13,478	1,600	11,597	281	8,139	1,488	3,467	3,184	314
22	Total Ener Rev Reqt		76,292	25,633	1,506	24,023	105	50,240	32,017	3,993	27,374	650	18,223	3,332	7,472	7,419	418
23	Annual kWh Sales		1,942,542,005	640,055,427	36,850,000	600,607,563	2,597,864	1,289,498,152	809,966,570	99,006,841	691,963,250	18,996,479	479,531,581	82,233,935	209,323,478	187,974,169	12,988,427
24	On Pk Reqt	Mills / kWh	21.587	20.635	20.392	20.647	21.262	22.197	22.889	24.175	22.800	19.420	21.028	22.422	19.132	22.530	8.003
25	Off Pk Reqt	Mills / kWh	17.687	19.414	20.481	19.350	19.016	16.764	16.640	16.158	16.760	14.809	16.974	18.098	16.565	16.937	24.179
26	Total Reqt	Mills / kWh	39.274	40.049	40.873	39.997	40.278	38.961	39.529	40.333	39.560	34.229	38.001	40.520	35.696	39.466	32.182
	Demand Component																
27	Base Load Prod		29,175	9,802	576	9,186	40	19,213	12,244	1,527	10,468	249	6,969	1,274	2,858	2,837	160
28	Summer Peak Prod		10,444	3,835	88	3,729	17	6,609	4,407	616	3,704	87	2,202	405	818	979	0
29	Winter Peak Prod		3,486	1,532	122	1,404	7	1,919	1,247	148	1,073	26	673	126	261	285	35
30	Total Production		43,105	15,169	786	14,319	64	27,742	17,897	2,291	15,245	361	9,844	1,806	3,936	4,102	194
31	Transmission **(Transco)**		13,756	5,486	276	5,186	24	8,210	5,418	712	4,597	109	2,793	518	1,057	1,218	60
32	Primary Dist Subs		4,612	1,893	108	1,776	8	2,678	1,691	236	1,421	34	987	183	361	443	42
33	Prim Dist Lines		3,704	1,355	30	1,318	6	2,318	1,458	169	1,258	31	860	165	310	385	32
34	Second Dist, Trans		4,517	2,534	136	2,388	10	1,954	1,577	227	1,349	(0)	377	140	(0)	237	28
35	Total Distribution **(Disco)**		12,832	5,782	275	5,482	24	6,949	4,725	633	4,028	65	2,224	488	671	1,065	101
36	Total Demand Rev Reqt		69,694	26,437	1,338	24,987	112	42,901	28,040	3,636	23,869	536	14,861	2,812	5,664	6,385	356
37	Annual Billing kW		3,059,299	0	0	0	0	3,059,299	2,025,150	0	1,966,057	59,092	1,034,149	167,901	372,394	493,854	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$6.28	$6.05	$0.00	$5.32	$4.21	$6.74	$7.59	$7.67	$5.75	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$2.16	$2.18	$0.00	$1.88	$1.47	$2.13	$2.41	$2.20	$1.98	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.63	$0.62	$0.00	$0.55	$0.44	$0.65	$0.75	$0.70	$0.58	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$9.07	$8.84	$0.00	$7.75	$6.12	$9.52	$10.75	$10.57	$8.31	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$2.68	$2.68	$0.00	$2.34	$1.85	$2.70	$3.09	$2.84	$2.47	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$2.27	$2.33	$0.00	$2.05	$1.10	$2.15	$2.91	$1.80	$2.16	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$0.00	$0.00	$0.00	$14.02	$13.85	$0.00	$12.14	$9.06	$14.37	$16.75	$15.21	$12.93	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	35.878	41.305	36.303	41.603	43.164	33.270	34.619	36.723	34.495	28.196	30.990	34.192	27.058	33.969	27.390
46	Summer Billing kW		1,117,880	0	0	0	0	1,117,880	733,515	0	713,765	19,749	384,365	55,342	143,234	185,788	0
47	Winter Billing kW		1,941,419	0	0	0	0	1,941,419	1,291,635	0	1,252,292	39,343	649,784	112,558	229,160	308,066	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$17.15	$17.06	$0.00	$14.90	$11.55	$17.32	$20.90	$18.02	$15.64	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$12.22	$12.02	$0.00	$10.57	$7.82	$12.63	$14.70	$13.45	$11.30	$0.00
50	Energy + Production **(Genco)**		119,397	40,803	2,292	38,342	169	77,982	49,915	6,285	42,619	1,012	28,067	5,138	11,409	11,521	612

PROP vs Equal Rev Reqts

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential						Small Comm & Indus				Large Comm & Indus		
	Total Retail Rev Reqt	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	**Proposed Ret On Rt Base**		**9.02%**	**8.88%**	**9.31%**	**8.88%**	**1.23%**	**9.18%**	**10.46%**	**9.31%**	**10.53%**	**17.23%**	**6.66%**	**5.47%**	**9.32%**	**4.79%**	**6.85%**
2	**UnAdj Equalized Rev Reqt**		**164,855**	**67,137**	**3,438**	**63,473**	**227**	**96,055**	**62,849**	**9,557**	**52,064**	**1,228**	**33,206**	**6,145**	**13,135**	**13,926**	**1,663**
3	**UnAdj Proposed Revenue**		**164,856**	**66,875**	**3,464**	**63,227**	**184**	**96,405**	**64,962**	**9,628**	**53,879**	**1,455**	**31,443**	**5,646**	**13,221**	**12,576**	**1,576**
4	**UnAdj Revenue Deficiency**		**(1)**	**262**	**(26)**	**246**	**43**	**(350)**	**(2,113)**	**(71)**	**(1,815)**	**(227)**	**1,763**	**499**	**(86)**	**1,350**	**87**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**0.39%**	**-0.76%**	**0.39%**	**23.25%**	**-0.36%**	**-3.25%**	**-0.74%**	**-3.37%**	**-15.61%**	**5.61%**	**8.83%**	**-0.65%**	**10.74%**	**5.50%**
6	**Interruption Rate Discounts**		**2,128**	**728**	**23**	**644**	**61**	**1,400**	**111**	**2**	**108**	**1**	**1,289**	**0**	**0**	**1,289**	**0**
7	**Interruptible Capacity Costs**	**D10C**	**2,128**	**820**	**32**	**784**	**4**	**1,302**	**863**	**117**	**730**	**17**	**439**	**81**	**165**	**193**	**5**
8	**Revenue Shift**		**0**	**92**	**9**	**140**	**(57)**	**(98)**	**752**	**115**	**622**	**16**	**(850)**	**81**	**165**	**(1,096)**	**5**
9	**Adj Equal Rev (Rows 2+8)**		**164,855**	**67,230**	**3,447**	**63,613**	**169**	**95,957**	**63,601**	**9,672**	**52,685**	**1,244**	**32,356**	**6,226**	**13,300**	**12,830**	**1,668**
10	**Prop Rev (Row 3)**		**164,856**	**66,875**	**3,464**	**63,227**	**184**	**96,405**	**64,962**	**9,628**	**53,879**	**1,455**	**31,443**	**5,646**	**13,221**	**12,576**	**1,576**
11	**Adj Revenue Deficiency**		**(1)**	**355**	**(17)**	**386**	**(15)**	**(448)**	**(1,361)**	**44**	**(1,194)**	**(211)**	**913**	**580**	**79**	**254**	**92**
12	**Adj Deficiency / Adj Prop**		**0.00%**	**0.53%**	**-0.50%**	**0.61%**	**-7.92%**	**-0.46%**	**-2.10%**	**0.45%**	**-2.22%**	**-14.49%**	**2.90%**	**10.27%**	**0.60%**	**2.02%**	**5.84%**
	Customer Component																
13	Min Sys & Service Drop		13,922	8,650	378	8,268	4	4,564	3,658	1,120	2,433	105	905	130	456	319	709
14	Energy Services		4,947	3,959	156	3,798	5	945	915	599	311	5	30	1	(0)	29	43
15	Total Customer **(Cusco)**		18,869	12,609	533	12,066	9	5,509	4,573	1,719	2,744	110	936	132	456	348	752
16	Ave Monthly Customers		82,176	70,041	2,757	67,120	164	10,182	10,060	7,167	2,845	48	122	9	5	108	1,954
17	Svc Drop Reqt	$ / Mo / Cust	$14.12	$10.29	$11.41	$10.26	$2.22	$37.35	$30.30	$13.02	$71.26	$184.07	$618.47	$1,254.38	$7,242.72	$245.71	$30.23
18	Ener Svcs Reqt	$ / Mo / Cust	$5.02	$4.71	$4.71	$4.72	$2.47	$7.74	$7.58	$6.97	$9.11	$8.95	$20.59	$11.26	($0.54)	$22.36	$1.83
19	Total Reqt	$ / Mo / Cust	$19.14	$15.00	$16.13	$14.98	$4.69	$45.09	$37.89	$19.99	$80.37	$193.02	$639.06	$1,265.64	$7,242.18	$268.08	$32.06
	Energy Component																
20	On Peak Rev Reqt		41,934	13,257	754	12,448	55	28,572	18,528	2,395	15,763	370	10,043	1,835	3,996	4,212	106
21	Off Peak Rev Reqt		34,358	12,452	755	11,648	49	21,592	13,485	1,604	11,598	283	8,107	1,481	3,458	3,168	314
22	Total Ener Rev Reqt		76,292	25,708	1,509	24,096	104	50,164	32,014	3,999	27,361	653	18,150	3,316	7,454	7,380	419
23	Annual kWh Sales		1,942,542,005	640,055,427	36,850,000	600,607,563	2,597,864	1,289,498,152	809,966,570	99,006,841	691,963,250	18,996,479	479,531,581	82,233,935	209,323,478	187,974,169	12,988,427
24	On Pk Reqt	Mills / kWh	21.587	20.712	20.448	20.726	21.095	22.157	22.876	24.190	22.780	19.501	20.943	22.314	19.089	22.408	8.148
25	Off Pk Reqt	Mills / kWh	17.687	19.454	20.492	19.393	18.865	16.745	16.649	16.203	16.761	14.886	16.907	18.013	16.522	16.851	24.137
26	Total Reqt	Mills / kWh	39.274	40.166	40.940	40.119	39.961	38.902	39.525	40.392	39.542	34.387	37.850	40.327	35.612	39.259	32.285
	Demand Component																
27	Base Load Prod		29,176	11,744	640	11,085	19	17,237	12,149	1,678	10,144	327	5,089	862	2,398	1,829	195
28	Summer Peak Prod		10,444	3,808	83	3,707	18	6,639	4,410	616	3,709	85	2,229	411	820	998	(3)
29	Winter Peak Prod		3,486	1,532	124	1,401	7	1,919	1,240	146	1,069	25	680	128	261	290	35
30	Total Production		43,106	17,083	847	16,193	43	25,796	17,798	2,440	14,921	437	7,998	1,402	3,479	3,117	227
31	Transmission **(Transco)**		13,757	5,777	297	5,465	14	7,901	5,550	770	4,639	141	2,351	410	1,028	913	80
32	Primary Dist Subs		4,612	1,980	108	1,868	4	2,595	1,815	261	1,506	48	780	134	346	300	37
33	Prim Dist Lines		3,704	1,453	49	1,399	4	2,221	1,484	188	1,259	37	737	135	296	306	30
34	Second Dist, Trans		4,517	2,265	121	2,139	5	2,220	1,728	251	1,448	29	492	118	161	213	31
35	Total Distribution **(Disco)**		12,833	5,698	278	5,406	14	7,036	5,027	700	4,213	114	2,009	387	803	819	99
36	Total Demand Rev Reqt		69,695	28,558	1,422	27,065	71	40,732	28,375	3,909	23,774	692	12,357	2,198	5,310	4,849	405
37	Annual Billing kW		3,059,299	0	0	0	0	3,059,299	2,025,150	0	1,966,057	59,092	1,034,149	167,901	372,394	493,854	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$5.63	$6.00	$0.00	$5.16	$5.53	$4.92	$5.14	$6.44	$3.70	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$2.17	$2.18	$0.00	$1.89	$1.44	$2.16	$2.45	$2.20	$2.02	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.63	$0.61	$0.00	$0.54	$0.43	$0.66	$0.76	$0.70	$0.59	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$8.43	$8.79	$0.00	$7.59	$7.40	$7.73	$8.35	$9.34	$6.31	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$2.58	$2.74	$0.00	$2.36	$2.38	$2.27	$2.44	$2.76	$1.85	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$2.30	$2.48	$0.00	$2.14	$1.92	$1.94	$2.30	$2.16	$1.66	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$0.00	$0.00	$0.00	$13.31	$14.01	$0.00	$12.09	$11.70	$11.95	$13.09	$14.26	$9.82	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	35.878	44.618	38.586	45.063	27.315	31.588	35.032	39.487	34.357	36.404	25.769	26.730	25.369	25.794	31.174
46	Summer Billing kW		1,117,880	0	0	0	0	1,117,880	733,515	0	713,765	19,749	384,365	55,342	143,234	185,788	0
47	Winter Billing kW		1,941,419	0	0	0	0	1,941,419	1,291,635	0	1,252,292	39,343	649,784	112,558	229,160	308,066	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$16.46	$17.23	$0.00	$14.86	$14.15	$14.94	$17.31	$17.08	$12.58	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$0.00	$11.51	$12.18	$0.00	$10.52	$10.48	$10.18	$11.02	$12.50	$8.15	$0.00
50	Energy + Production **(Genco)**		119,397	42,792	2,355	40,289	147	75,960	49,812	6,439	42,283	1,090	26,148	4,718	10,933	10,497	646
51	Prop Rev - Pres Rev (Pg 2)		18,472	8,411	374	8,010	27	9,864	6,788	1,182	5,457	149	3,076	538	1,186	1,352	197
52	Difference / Present		12.62%	14.39%	12.10%	14.51%	17.20%	11.40%	11.67%	13.99%	11.27%	11.41%	10.84%	10.53%	9.85%	12.05%	14.29%
53	Adj Prop - Adj Pres (Pg 2)		18,472	8,411	374	8,010	27	9,864	6,788	1,182	5,457	149	3,076	538	1,186	1,352	197
54	Difference / Adj Present		12.62%	14.39%	12.10%	14.51%	17.20%	11.40%	11.67%	13.99%	11.27%	11.41%	10.84%	10.53%	9.85%	12.05%	14.29%

Original Plant in Service

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential					Small Comm & Indus				Large Comm & Indus			
	Production	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Summer Peak	D10S	74,669	27,427	632	26,671	124	47,242	31,500	4,404	26,475	621	15,742	2,896	5,847	6,999	0
2	WInter Peak	D10W	24,930	10,961	877	10,037	47	13,719	8,911	1,057	7,669	185	4,808	902	1,866	2,040	249
3	Total Peak	[D10C]	99,599	38,388	1,509	36,709	171	60,961	40,411	5,461	34,144	806	20,551	3,798	7,713	9,039	249
4	Base Load	D8760	169,510	56,954	3,346	53,375	232	111,627	71,138	8,873	60,821	1,445	40,489	7,404	16,602	16,483	928
5	Nuclear Fuel	D8760	73,714	24,768	1,455	23,211	101	48,543	30,936	3,858	26,449	628	17,607	3,220	7,220	7,168	404
6	Total	37.01%	342,823	120,110	6,311	113,295	504	221,131	142,485	18,191	121,414	2,879	78,647	14,421	31,535	32,691	1,581
	Transmission																
7	Gen Step Up Base	D8760	1,026	345	20	323	1	676	431	54	368	9	245	45	100	100	6
8	Gen Step Up Peak	D10C	1,256	484	19	463	2	769	510	69	431	10	259	48	97	114	3
9	Total Gen Step Up		2,282	829	39	786	4	1,444	940	123	799	19	504	93	198	214	9
10	Bulk Transmission	D10T	79,884	31,858	1,605	30,113	140	47,678	31,460	4,135	26,692	633	16,218	3,008	6,135	7,074	347
11	Distrib Function	D60Sub	111	46	3	43	0	64	41	6	34	1	23	4	8	10	1
12	Direct Assign	Dir Assign	10	0	0	0	0	10	0	0	0	0	10	0	0	10	0
13	Total		82,287	32,733	1,647	30,942	144	49,196	32,441	4,263	27,525	653	16,755	3,105	6,341	7,308	357
	Distribution: Substations																
14	Generat Step Up	STRATH	182	64	3	60	0	117	76	10	64	2	42	8	17	17	1
15	Bulk Transmission	D10T	109	43	2	41	0	65	43	6	36	1	22	4	8	10	0
16	Distrib Function	D60Sub	32,141	13,283	761	12,468	55	18,566	11,870	1,658	9,971	242	6,696	1,283	2,409	3,004	291
17	Direct Assign	Dir Assign	250	0	0	0	0	250	0	0	0	0	250	0	150	100	0
18	Total		32,682	13,391	766	12,569	55	18,999	11,989	1,673	10,072	244	7,010	1,295	2,584	3,131	293
	Overhead Lines																
19	Primary Capacity	D61PS	16,455	6,017	135	5,855	28	10,296	6,475	751	5,588	137	3,821	733	1,376	1,712	141
20	Primary Customer	C61PS	10,954	9,518	375	9,142	0	1,387	1,370	976	388	6	17	1	1	15	49
21	Total Primary		27,409	15,535	510	14,997	28	11,683	7,846	1,727	5,975	143	3,838	734	1,377	1,727	191
22	Second Capacity	D62SecL	6,390	3,418	186	3,219	14	2,926	2,355	334	2,021	0	571	215	0	356	45
23	Second Customer	C62Sec	6,894	5,995	236	5,758	0	868	859	615	244	0	9	1	0	9	31
24	Total Secondary		13,284	9,413	422	8,977	14	3,795	3,214	949	2,265	0	581	216	0	365	76
25	Street Lighting	DASL	1,586	0	0	0	0	0	0	0	0	0	0	0	0	0	1,586
26	Total		42,279	24,948	933	23,974	41	15,478	11,060	2,676	8,240	143	4,418	949	1,377	2,092	1,853
	Underground Lines																
27	Primary Capacity	D61PS	4,575	1,673	37	1,628	8	2,863	1,800	209	1,554	38	1,062	204	383	476	39
28	Primary Customer	C61PS	27,535	23,925	944	22,981	0	3,486	3,444	2,454	974	16	42	3	2	37	124
29	Total Primary		32,110	25,598	981	24,609	8	6,349	5,245	2,663	2,528	54	1,104	207	384	513	163
30	Second Capacity	D62SecL	12,646	6,765	368	6,370	27	5,792	4,661	662	3,999	0	1,130	425	0	705	90
31	Second Customer	C62Sec	14,972	13,019	514	12,505	0	1,886	1,865	1,335	530	0	20	2	0	19	68
32	Total Secondary		27,618	19,783	882	18,875	27	7,677	6,527	1,997	4,529	0	1,151	427	0	724	157
33	Total		59,728	45,381	1,863	43,484	35	14,026	11,771	4,660	7,057	54	2,255	633	384	1,237	321
	Line Transformers																
34	Primary	D61PS	751	275	6	267	1	470	296	34	255	6	174	33	63	78	6
35	Second Capacity	D62SecL	7,477	4,000	218	3,766	16	3,424	2,756	391	2,365	0	668	251	0	417	53
36	Second Customer	C62Sec	5,779	5,025	198	4,827	0	728	720	515	205	0	8	1	0	7	26
37	Total		14,007	9,299	422	8,860	17	4,622	3,771	941	2,824	6	851	285	63	502	86
	Services																
38	Second Capacity	D62NLL	5,369	4,105	208	3,882	15	1,264	1,061	187	874	0	204	59	0	144	0
39	Second Customer	C62NL	13,610	12,606	497	12,108	0	1,004	993	711	282	0	11	1	0	10	0
40	Total		18,979	16,710	705	15,990	15	2,269	2,054	898	1,156	0	214	60	0	154	0
41	Meters	C12WM	5,704	3,600	141	3,440	19	2,056	1,765	1,184	470	112	291	2	12	277	48
42	Street Lighting	Dir Assign	1,693	0	0	0	0	0	0	0	0	0	0	0	0	0	1,693
43	**Total Distribution**		175,072	113,329	4,830	108,316	182	57,450	42,411	12,032	29,819	560	15,039	3,225	4,420	7,394	4,293
44	**General Plant**	PTD	13,997	6,208	298	5,890	19	7,644	5,069	804	4,169	95	2,576	484	986	1,105	145
45	**Electric Common**	PTD	21,141	9,376	450	8,896	29	11,546	7,656	1,215	6,297	144	3,890	731	1,490	1,669	219
46	Prelim Elec Plant		635,319	281,755	13,536	267,339	880	346,968	230,061	36,505	189,224	4,331	116,907	21,967	44,773	50,167	6,596
47	TBT Investment	NEPIS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	**Elec Plant in Serv**		635,319	281,755	13,536	267,339	880	346,968	230,061	36,505	189,224	4,331	116,907	21,967	44,773	50,167	6,596

	Accum Deprec; Net Plant		1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential					Small Comm & Indus				Large Comm & Indus			
	Production	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Peaking Plant	D10C	99,188	38,230	1,503	36,557	170	60,710	40,244	5,438	34,003	803	20,466	3,782	7,681	9,002	248
2	Nuclear Fuel	D8760	67,965	22,836	1,342	21,401	93	44,757	28,523	3,557	24,386	579	16,234	2,968	6,657	6,609	372
3	Base Load	D8760	37,496	12,598	740	11,807	51	24,692	15,736	1,963	13,454	320	8,956	1,638	3,672	3,646	205
4	Total		204,648	73,664	3,585	69,765	315	130,159	84,503	10,958	71,843	1,701	45,656	8,389	18,010	19,257	826
	Transmission																
5	Gen Step Up Base	D8760	562	189	11	177	1	370	236	29	202	5	134	25	55	55	3
6	Gen Step Up Peak	D10C	689	266	10	254	1	422	280	38	236	6	142	26	53	63	2
7	Total Gen Step Up		1,251	454	22	431	2	792	515	67	438	10	276	51	108	117	5
8	Bulk Transmission	D10T	25,712	10,254	517	9,692	45	15,346	10,126	1,331	8,591	204	5,220	968	1,975	2,277	112
9	Distrib Function	D60Sub	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	3	0	0	0	0	3	0	0	0	0	3	0	0	3	0
11	Total		26,967	10,709	538	10,124	47	16,141	10,642	1,398	9,029	214	5,500	1,019	2,083	2,397	117
	Distribution																
12	Generat Step Up	STRATH	66	23	1	22	0	43	27	4	23	1	15	3	6	6	0
13	Bulk Transmission	D10T	41	16	1	15	0	24	16	2	14	0	8	2	3	4	0
14	Distrib Function	D60Sub	9,558	3,950	226	3,708	16	5,521	3,530	493	2,965	72	1,991	382	716	893	87
15	Direct Assign	Dir Assign	99	0	0	0	0	99	0	0	0	0	99	0	69	30	0
16	Total Substations		9,764	3,990	228	3,745	16	5,687	3,574	499	3,002	73	2,114	386	795	933	87
17	Overhead Lines	POL	22,739	13,418	502	12,894	22	8,325	5,948	1,439	4,432	77	2,376	511	741	1,125	997
18	Underground	PUL	17,000	12,917	530	12,376	10	3,992	3,350	1,326	2,009	15	642	180	109	352	91
19	Line Transformers	P68	4,497	2,986	135	2,845	6	1,484	1,211	302	907	2	273	92	20	161	27
20	Services	P69	9,436	8,308	351	7,950	7	1,128	1,021	447	575	0	107	30	0	77	0
21	Meters	C12WM	809	511	20	488	3	292	250	168	67	16	41	0	2	39	7
22	Street Lighting	P73	1,402	0	0	0	0	0	0	0	0	0	0	0	0	0	1,402
23	Total		65,647	42,128	1,766	40,298	64	20,908	15,355	4,181	10,991	183	5,553	1,199	1,667	2,688	2,611
24	**General Plant**	PTD	5,136	2,278	109	2,161	7	2,805	1,860	295	1,530	35	945	178	362	406	53
25	**Electric Common**	PTD	11,690	5,184	249	4,919	16	6,384	4,233	672	3,482	80	2,151	404	824	923	121
26	**Total Accum Depr**		314,088	133,963	6,247	127,266	449	176,397	116,592	17,504	96,875	2,214	59,805	11,188	22,946	25,671	3,728
27	**Net Elec Plant**		321,232	147,792	7,289	140,073	430	170,571	113,469	19,002	92,349	2,118	57,102	10,779	21,827	24,497	2,868
	Subtractions: Accum Defer Inc Tax																
	Production																
28	Peaking Plant	D10C	8,206	3,163	124	3,024	14	5,023	3,329	450	2,813	66	1,693	313	635	745	21
29	Base Load	D8760	13,385	4,497	264	4,215	18	8,815	5,617	701	4,803	114	3,197	585	1,311	1,302	73
30	Nuclear Fuel	D8760	219	74	4	69	0	144	92	11	79	2	52	10	21	21	1
31	Total		21,810	7,734	393	7,308	33	13,981	9,039	1,162	7,694	182	4,943	907	1,968	2,068	95
	Transmission																
32	Gen Step Up Base	D8760	120	40	2	38	0	79	50	6	43	1	29	5	12	12	1
33	Gen Step Up Peak	D10C	146	56	2	54	0	89	59	8	50	1	30	6	11	13	0
34	Total Gen Step Up		266	97	5	92	0	168	110	14	93	2	59	11	23	25	1
35	Bulk Transmission	D10T	8,976	3,580	180	3,384	16	5,357	3,535	465	2,999	71	1,822	338	689	795	39
36	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Direct Assign	Dir Assign	1	0	0	0	0	1	0	0	0	0	1	0	0	1	0
38	Total		9,243	3,676	185	3,475	16	5,527	3,645	479	3,092	73	1,882	349	712	821	40
	Distribution																
39	Generat Step Up	STRATH	34	12	1	11	0	22	14	2	12	0	8	1	3	3	0
40	Bulk Transmission	D10T	13	5	0	5	0	8	5	1	4	0	3	0	1	1	0
41	Distrib Function	D60Sub	4,540	1,876	107	1,761	8	2,623	1,677	234	1,408	34	946	181	340	424	41
42	Direct Assign	Dir Assign	21	0	0	0	0	21	0	0	0	0	21	0	15	6	0
43	Total Substations		4,608	1,893	108	1,777	8	2,673	1,696	237	1,425	35	977	183	359	435	41
44	Overhead Lines	POL	5,132	3,028	113	2,910	5	1,879	1,342	325	1,000	17	536	115	167	254	225
45	Underground	PUL	7,614	5,785	237	5,543	4	1,788	1,501	594	900	7	287	81	49	158	41
46	Line Transformers	P68	2,078	1,380	63	1,314	3	686	560	140	419	1	126	42	9	75	13
47	Services	P69	2,586	2,277	96	2,179	2	309	280	122	158	0	29	8	0	21	0
48	Meters	C12WM	679	428	17	409	2	245	210	141	56	13	35	0	1	33	6
49	Street Lighting	P73	(253)	0	0	0	0	0	0	0	0	0	0	0	0	0	(253)
50	Total		22,444	14,792	635	14,133	24	7,580	5,589	1,558	3,957	73	1,991	430	586	975	73
51	**General Plant**	PTD	1,300	577	28	547	2	710	471	75	387	9	239	45	92	103	14
52	**Electric Common**	PTD	1,821	808	39	766	3	995	659	105	542	12	335	63	128	144	19
53	**Total Deferred Tax**		56,619	27,586	1,279	26,230	77	28,792	19,402	3,379	15,673	350	9,390	1,794	3,486	4,110	240
54	TBT Acc Def Tax	NEPIS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55	Non-Plant Related	LABOR	(825)	(347)	(17)	(329)	(1)	(467)	(309)	(50)	(252)	(6)	(158)	(29)	(62)	(67)	(11)
56	**Accum Def W/ Adj**		55,794	27,239	1,262	25,901	76	28,326	19,094	3,328	15,421	344	9,232	1,765	3,425	4,043	229

Additions: CWIP, Etc; Rate Base

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
	CWIP				Residential					Small Comm & Indus				Large Comm & Indus			
	Production	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Base Load	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Nuclear Fuel	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Total		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission																
5	Gen Step Up Base	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution																
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Total		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	**Total CWIP**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Fuel Inventory	E8760	5,879	1,975	116	1,851	8	3,871	2,467	308	2,109	50	1,404	257	576	572	32
	Materials & Supplies																
28	Production	P10	4,068	1,425	75	1,344	6	2,624	1,691	216	1,441	34	933	171	374	388	19
29	Trans & Distr	TD	876	497	22	474	1	363	255	55	195	4	108	22	37	50	16
30	Total		4,944	1,922	97	1,818	7	2,987	1,946	271	1,636	38	1,041	193	411	438	35
	Prepayments																
31	Miscellaneous	NEPIS	7,149	3,289	162	3,117	10	3,796	2,525	423	2,055	47	1,271	240	486	545	64
32	Total		7,149	3,289	162	3,117	10	3,796	2,525	423	2,055	47	1,271	240	486	545	64
33	Non-Plant Assets & Liab	LABOR	(2,637)	(1,109)	(53)	(1,052)	(4)	(1,492)	(987)	(161)	(806)	(19)	(506)	(93)	(197)	(215)	(36)
34	Working Cash	PT0	1,866	837	40	795	3	1,008	674	111	550	13	334	63	126	145	21
35	**Total Additions**		17,201	6,915	362	6,530	24	10,171	6,626	952	5,545	129	3,545	659	1,401	1,485	115
36	**Total Rate Base**		282,639.20	127,469	6,389	120,702	378	152,416	101,001	16,626	82,473	1,903	51,415	9,673	19,803	21,939	2,754
37	**Common Rate Base (@ 51.63%)**		145,926.6	65,812	3,298	62,319	195	78,693	52,147	8,584	42,581	982	26,546	4,994	10,224	11,327	1,422

	Operating Rev (Cal Month)		1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential					**Small Comm & Indus**				**Large Comm & Indus**			
	Retail Revenue	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Present Rate Revenue	R01; (calc)	146,384	58,464	3,090	55,217	157	86,541	58,174	8,446	48,422	1,306	28,367	5,108	12,035	11,224	1,379
2	Proposed Rate Revenue	PROREV; (cal	164,856	66,875	3,464	63,227	184	96,405	64,962	9,628	53,879	1,455	31,443	5,646	13,221	12,576	1,576
	Other Retail Revenue																
3	Interdepartmental	R01; R02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	CIP Adjustment to Program Costs	D48E52	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Tot Other Retail Rev**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Other Operating Revenue																
7	Interchg Prod Capacity	P10	7,257	2,543	134	2,398	11	4,681	3,016	385	2,570	61	1,665	305	668	692	33
8	Interchg Prod Energy	E8760	10,959	3,682	216	3,451	15	7,217	4,599	574	3,932	93	2,618	479	1,073	1,066	60
9	Interchg Tr Bulk Supply	D10T	1,641	654	33	619	3	979	646	85	548	13	333	62	126	145	7
10	Dist Int Sales; Oth Serv	E8760	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Dist Overhd Line Rent	POL	241	142	5	137	0	88	63	15	47	1	25	5	8	12	11
12	Connection Charges	C11	227	193	8	185	0	28	28	20	8	0	0	0	0	0	5
13	Sales For Resale	E8760	9,782	3,287	193	3,080	13	6,442	4,105	512	3,510	83	2,337	427	958	951	54
14	Joint Op Agree-Other PSCo Rev	D10T	(160)	(64)	(3)	(60)	(0)	(95)	(63)	(8)	(53)	(1)	(32)	(6)	(12)	(14)	(1)
15	Production Assoc'd Rev	E8760	305	102	6	96	0	201	128	16	109	3	73	13	30	30	2
16	Misc Ancillary Trans Rev	D10T	3,719	1,483	75	1,402	7	2,220	1,465	192	1,243	29	755	140	286	329	16
17	MISO	D10T	368	147	7	139	1	220	145	19	123	3	75	14	28	33	2
18	Other	D10T	240	96	5	90	0	143	95	12	80	2	49	9	18	21	1
19	Late Pay Chg - Pres	R16C; R02	354	141	7	134	0	209	141	20	117	3	69	12	29	27	3
20	**Tot Other Op - Pres**		34,933	12,407	686	11,670	51	22,332	14,367	1,843	12,234	290	7,965	1,461	3,212	3,292	193
21	Incr Misc Serv - Prop	R01,	66	26	1	25	0	39	26	4	22	1	13	2	5	5	1
22	Incr Inter Departmental - Prop	R01; R02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Incr Late Pay - Prop	(R16C); R02	45	18	1	17	0	26	18	3	15	0	9	2	4	3	0
24	**Tot Other Op - Prop**		35,044	12,452	689	11,712	51	22,398	14,411	1,849	12,271	291	7,987	1,465	3,221	3,301	194
25	**Tot Oper Rev - Pres**		181,317	70,871	3,776	66,887	208	108,873	72,541	10,289	60,656	1,596	36,332	6,569	15,247	14,516	1,572
26	**Tot Oper Rev - Prop**		199,900	79,327	4,153	74,939	235	118,803	79,373	11,477	66,150	1,746	39,430	7,111	16,442	15,877	1,770
	Operating & Maint (Pg 1 of 2)																
	Production Expen																
27	**Fuel**	E8760	28,589	9,606	564	9,002	39	18,827	11,998	1,496	10,258	244	6,829	1,249	2,800	2,780	157
	Purchased Power																
28	Purchases: Cap Peak	D10C	4,689	1,807	71	1,728	8	2,870	1,902	257	1,607	38	968	179	363	426	12
29	Purchases: Cap Base	D8760	3,829	1,286	76	1,206	5	2,521	1,607	200	1,374	33	915	167	375	372	21
30	Purchases: Demand		8,518	3,094	147	2,934	13	5,391	3,509	457	2,981	71	1,882	346	738	798	33
31	Purchases: Other Energy	E8760	44,800	15,053	884	14,107	61	29,502	18,801	2,345	16,075	382	10,701	1,957	4,388	4,356	245
32	Tot Non-Assoc Purch		53,318	18,146	1,031	17,041	75	34,894	22,311	2,802	19,056	452	12,583	2,303	5,126	5,154	278
33	Interchg Agr Capacity	P10	2,101	736	39	694	3	1,355	873	111	744	18	482	88	193	200	10
34	Interchg Agr Energy	E8760	1,232	414	24	388	2	811	517	64	442	11	294	54	121	120	7
35	Tot Wis Interchg Purch		3,333	1,150	63	1,082	5	2,166	1,390	176	1,186	28	776	142	314	320	16
36	**Tot Purchased Power**		56,651	19,296	1,094	18,123	80	37,060	23,701	2,978	20,242	481	13,359	2,445	5,440	5,474	294
	Other Production																
37	Capacity Peaking	D10C	3,586	1,382	54	1,322	6	2,195	1,455	197	1,229	29	740	137	278	325	9
38	Capacity Baseload	D8760	2,928	984	58	922	4	1,928	1,229	153	1,051	25	699	128	287	285	16
39	Total Capacity		6,514	2,366	112	2,244	10	4,123	2,684	350	2,280	54	1,439	265	565	610	25
40	Energy	E8760	15,907	5,345	314	5,009	22	10,475	6,676	833	5,708	136	3,800	695	1,558	1,547	87
41	Total Other Produc		22,421	7,711	426	7,253	32	14,598	9,360	1,182	7,988	190	5,239	959	2,122	2,157	112
42	**Total Production**		107,661	36,613	2,085	34,377	151	70,485	45,058	5,657	38,487	914	25,427	4,653	10,362	10,411	563
43	**Transmission Exp**	D10T	7,988	3,186	160	3,011	14	4,767	3,146	413	2,669	63	1,622	301	613	707	35

Operating & Maint (Pg 2 of 2)

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential					Small Comm & Indus				Large Comm & Indus			
	Distribution Expen	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Supervision & Eng'rg	ZDTS	1,111	661	27	632	1	390	287	87	194	5	103	21	31	51	60
2	Load Dispatching	D10T	221	88	4	83	0	132	87	11	74	2	45	8	17	20	1
3	Substations	P61	395	162	9	152	1	229	145	20	122	3	85	16	31	38	4
4	Overhead Lines	POL	1,653	975	36	937	2	605	432	105	322	6	173	37	54	82	72
5	Underground Lines	PUL	1,202	914	37	875	1	282	237	94	142	1	45	13	8	25	6
6	Line Transformers	P68	9	6	0	6	0	3	2	1	2	0	1	0	0	0	0
7	Meters	C12WM	245	155	6	148	1	88	76	51	20	5	13	0	1	12	2
8	Customer Install'n	OXDTS	104	61	2	58	0	35	26	7	18	0	10	2	3	5	7
9	Street Lighting	Dir Assign	200	0	0	0	0	0	0	0	0	0	0	0	0	0	200
10	Miscellaneous	OXDTS	726	425	17	407	1	248	181	52	127	3	67	14	21	33	52
11	Rents (Pole Attachmts)	POL	181	107	4	102	0	66	47	11	35	1	19	4	6	9	8
12	**Total Distribution**		6,045	3,552	145	3,400	7	2,080	1,521	439	1,056	26	559	114	171	274	413
13	**Customer Accounting**	C11WA	4,244	3,382	133	3,245	4	828	799	520	275	5	28	1	1	26	34
14	**Econ Development**	D100E0	103	38	1	37	0	65	43	6	37	1	22	4	8	10	0
	Admin & General																
15	Salaries	LABOR	3,320	1,396	67	1,324	5	1,879	1,242	203	1,015	24	637	118	249	270	45
16	Office Supplies	OXTS	2,065	774	41	730	3	1,273	824	116	691	16	449	82	181	186	18
17	Admin Transfer Credit	OXTS	(863)	(324)	(17)	(305)	(1)	(532)	(344)	(48)	(289)	(7)	(188)	(34)	(75)	(78)	(7)
18	Outside Services	LABOR	1,049	441	21	418	1	593	392	64	321	8	201	37	79	85	14
19	Property Insurance	NEPIS	294	135	7	128	0	156	104	17	85	2	52	10	20	22	3
20	Pensions & Benefits	LABOR	3,250	1,366	66	1,296	5	1,839	1,216	199	993	24	623	115	243	265	44
21	Injuries & Claims	LABOR	610	256	12	243	1	345	228	37	186	4	117	22	46	50	8
22	Regulatory Exp	R01; R02	326	130	7	123	0	193	130	19	108	3	63	11	27	25	3
23	General Advertising	OXTS	25	9	0	9	0	15	10	1	8	0	5	1	2	2	0
24	Contributions	OXTS	59	22	1	21	0	36	24	3	20	0	13	2	5	5	1
25	Misc General Exp	OXTS	(9)	(4)	(0)	(3)	(0)	(6)	(4)	(1)	(3)	(0)	(2)	(0)	(1)	(1)	(0)
26	Rents	OXTS	712	267	14	252	1	439	284	40	239	6	155	28	62	64	6
27	Maint of General Plant	OXTS	27	10	1	9	0	16	11	1	9	0	6	1	2	2	0
28	Total		10,864	4,481	221	4,245	15	6,247	4,116	652	3,382	81	2,131	393	839	899	136
	Cust Service & Info																
29	Cust Assist Exp - Non-CIP	C11P10	201	121	5	115	0	77	54	14	39	1	23	4	9	10	3
30	CIP Total	D48E52	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Instructional Advertising	C11P10	131	79	3	75	0	50	35	9	25	1	15	3	6	6	2
32	Total		332	200	9	190	1	128	89	23	65	1	38	7	15	16	5
33	Amortizations	LABOR	352	148	7	140	0	199	132	22	108	3	67	12	26	29	5
34	**Total O&M Expense**		137,588	51,599	2,761	48,647	192	84,799	54,905	7,733	46,078	1,094	29,895	5,486	12,036	12,372	1,190

Book Depreciation

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential					Small Comm & Indus				Large Comm & Indus			
	Production	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Peaking Plant	D10C	3,661	1,411	55	1,349	6	2,241	1,486	201	1,255	30	755	140	284	332	9
2	Base Load	D8760	7,191	2,416	142	2,264	10	4,735	3,018	376	2,580	61	1,718	314	704	699	39
3	Total		10,852	3,827	197	3,614	16	6,976	4,503	577	3,835	91	2,473	454	988	1,032	49
	Transmission																
4	Gen Step Up Base	D8760	27	9	1	9	0	18	11	1	10	0	6	1	3	3	0
5	Gen Step Up Peak	D10C	33	13	0	12	0	20	13	2	11	0	7	1	3	3	0
6	Total Gen Step Up		60	22	1	21	0	38	25	3	21	0	13	2	5	6	0
7	Bulk Transmission	D10T	2,094	835	42	789	4	1,250	825	108	700	17	425	79	161	185	9
8	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Total		2,154	857	43	810	4	1,288	849	112	721	17	438	81	166	191	9
	Distribution																
11	Generat Step Up	STRATH	5	2	0	2	0	3	2	0	2	0	1	0	0	0	0
12	Bulk Transmission	D10T	3	1	0	1	0	2	1	0	1	0	1	0	0	0	0
13	Distrib Function	D60Sub	1,021	422	24	396	2	590	377	53	317	8	213	41	77	95	9
14	Direct Assign	Dir Assign	7	0	0	0	0	7	0	0	0	0	7	0	4	3	0
15	Total Substations		1,036	425	24	399	2	602	380	53	320	8	221	41	81	99	9
16	Overhead Lines	POL	1,762	1,040	39	999	2	645	461	112	343	6	184	40	57	87	77
17	Underground	PUL	1,342	1,020	42	977	1	315	264	105	159	1	51	14	9	28	7
18	Line Transformers	P68	403	268	12	255	0	133	109	27	81	0	24	8	2	14	2
19	Services	P69	642	565	24	541	1	77	69	30	39	0	7	2	0	5	0
20	Meters	C12WM	367	232	9	221	1	132	114	76	30	7	19	0	1	18	3
21	Street Lighting	P73	81	0	0	0	0	0	0	0	0	0	0	0	0	0	81
22	Total		5,633	3,549	150	3,392	6	1,904	1,397	403	972	22	507	105	150	251	180
23	**General Plant**	PTD	992	440	21	417	1	542	359	57	295	7	182	34	70	78	10
24	**Electric Common**	PTD	1,839	816	39	774	3	1,004	666	106	548	13	338	64	130	145	19
25	**Total Book Deprec**		21,470	9,488	451	9,007	30	11,714	7,775	1,254	6,371	150	3,939	738	1,503	1,698	268

Real Estate & Property Tax

			MN	Res Tot	Res W/	Res W/o	Ld Mgmt	C&I Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Interrupt	Ltg Tot
	Production																
26	Peaking Plant	D10C	600	231	9	221	1	367	243	33	206	5	124	23	46	54	2
27	Base Load	D8760	1,718	577	34	541	2	1,131	721	90	616	15	410	75	168	167	9
28	Total		2,318	808	43	762	3	1,499	964	123	822	19	534	98	215	222	11
	Transmission																
29	Gen Step Up Base	D8760	54	18	1	17	0	36	23	3	19	0	13	2	5	5	0
30	Gen Step Up Peak	D10C	189	73	3	70	0	116	77	10	65	2	39	7	15	17	0
31	Total Gen Step Up		243	91	4	87	0	151	99	13	84	2	52	10	20	22	1
32	Bulk Transmission	D10T	851	339	17	321	1	508	335	44	284	7	173	32	65	75	4
33	Distrib Function	D60Sub	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
34	Direct Assign	Dir Assign	(1)	0	0	0	0	(1)	0	0	0	0	(1)	0	0	(1)	0
35	Total		1,094	431	21	408	2	659	435	57	369	9	224	42	85	97	4
	Distribution																
36	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Bulk Transmission	D10T	25	10	1	9	0	15	10	1	8	0	5	1	2	2	0
38	Distrib Function	D60Sub	252	104	6	98	0	146	93	13	78	2	52	10	19	24	2
39	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Substations		277	114	6	107	0	160	103	14	87	2	58	11	21	26	2
41	Overhead Lines	POL	287	169	6	163	0	105	75	18	56	1	30	6	9	14	13
42	Underground	PUL	432	328	13	315	0	101	85	34	51	0	16	5	3	9	2
43	Line Transformers	P68	295	196	9	187	0	97	79	20	59	0	18	6	1	11	2
44	Services	P69	118	104	4	99	0	14	13	6	7	0	1	0	0	1	0
45	Meters	C12WM	116	73	3	70	0	42	36	24	10	2	6	0	0	6	1
46	Street Lighting	P73	19	0	0	0	0	0	0	0	0	0	0	0	0	0	19
47	Total		1,544	985	42	940	2	520	391	116	270	6	129	28	35	66	39
48	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
49	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50	**Tot Rl Est & Pr Tax**		4,956	2,224	106	2,110	7	2,678	1,791	296	1,461	34	887	168	335	384	54
51	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
52	Payroll Taxes	LABOR	1,452	610	29	579	2	822	543	89	444	11	278	51	109	118	20
53	**Tot Non-Inc Taxes**		6,408	2,834	136	2,689	9	3,499	2,334	384	1,904	45	1,165	219	443	503	74

Provision For Defer Inc Tax

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential					Small Comm & Indus				Large Comm & Indus			
	Production	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Peaking Plant	D10C	1,906	734	29	702	3	1,166	773	104	653	15	393	73	148	173	5
2	Nuclear Fuel	D8760	611	205	12	192	1	402	256	32	219	5	146	27	60	59	3
3	Base Load	D8760	1,138	383	22	358	2	750	478	60	408	10	272	50	112	111	6
4	Total		3,655	1,322	63	1,253	6	2,318	1,507	196	1,281	30	811	149	319	343	14
	Transmission																
5	Gen Step Up Base	D8760	(10)	(3)	(0)	(3)	(0)	(7)	(4)	(1)	(4)	(0)	(2)	(0)	(1)	(1)	(0)
6	Gen Step Up Peak	D10C	(12)	(5)	(0)	(4)	(0)	(7)	(5)	(1)	(4)	(0)	(2)	(0)	(1)	(1)	(0)
7	Total Gen Step Up		(22)	(8)	(0)	(8)	(0)	(14)	(9)	(1)	(8)	(0)	(5)	(1)	(2)	(2)	(0)
8	Bulk Transmission	D10T	1,582	631	32	596	3	944	623	82	529	13	321	60	122	140	7
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total		1,560	623	31	589	3	930	614	81	521	12	316	59	120	138	7
	Distribution																
12	Generat Step Up	STRATH	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	(295)	(122)	(7)	(114)	(1)	(170)	(109)	(15)	(92)	(2)	(61)	(12)	(22)	(28)	(3)
15	Direct Assign	Dir Assign	(1)	0	0	0	0	(1)	0	0	0	0	(1)	0	(1)	(0)	0
16	Total Substations		(294)	(121)	(7)	(114)	(1)	(170)	(108)	(15)	(91)	(2)	(62)	(12)	(23)	(28)	(3)
17	Overhead Lines	POL	326	192	7	185	0	119	85	21	64	1	34	7	11	16	14
18	Underground	PUL	809	615	25	589	0	190	159	63	96	1	31	9	5	17	4
19	Line Transformers	P68	(43)	(29)	(1)	(27)	(0)	(14)	(12)	(3)	(9)	(0)	(3)	(1)	(0)	(2)	(0)
20	Services	P69	(336)	(296)	(12)	(283)	(0)	(40)	(36)	(16)	(20)	0	(4)	(1)	0	(3)	0
21	Meters	C12WM	12	8	0	7	0	4	4	2	1	0	1	0	0	1	0
22	Street Lighting	P73	(1)	0	0	0	0	0	0	0	0	0	0	0	0	0	(1)
23	Total		473	369	12	357	0	89	92	52	40	(0)	(3)	2	(7)	1	15
24	**General Plant**	PTD	52	23	1	22	0	28	19	3	15	0	10	2	4	4	1
25	**Electric Common**	PTD	(170)	(75)	(4)	(72)	(0)	(93)	(62)	(10)	(51)	(1)	(31)	(6)	(12)	(13)	(2)
26	**TBT Defer Inc Tax**	NEPIS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	**Non - Plant Related**	LABOR	(571)	(240)	(12)	(228)	(1)	(323)	(214)	(35)	(175)	(4)	(109)	(20)	(43)	(47)	(8)
28	**Tot Prov For Defer**		4,999	2,022	93	1,922	7	2,950	1,957	287	1,632	38	993	186	381	427	27

Inv Tax Credit; Total Oper Exp

			MN	Res Tot	Res W/	Res W/o	Ld Mgmt	C&I Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Interrupt	Ltg Tot
	Production																
29	Peaking Plant	D10C	(67)	(26)	(1)	(25)	(0)	(41)	(27)	(4)	(23)	(1)	(14)	(3)	(5)	(6)	(0)
30	Base Load	D8760	(25)	(8)	(0)	(8)	(0)	(16)	(10)	(1)	(9)	(0)	(6)	(1)	(2)	(2)	(0)
31	Total		(92)	(34)	(2)	(33)	(0)	(57)	(38)	(5)	(32)	(1)	(20)	(4)	(8)	(9)	(0)
	Transmission																
32	Bulk Transmission	D10T	(28)	(11)	(1)	(11)	(0)	(17)	(11)	(1)	(9)	(0)	(6)	(1)	(2)	(2)	(0)
33	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Total		(28)	(11)	(1)	(11)	(0)	(17)	(11)	(1)	(9)	(0)	(6)	(1)	(2)	(2)	(0)
	Distribution																
35	Overhead Lines	POL	(19)	(11)	(0)	(11)	(0)	(7)	(5)	(1)	(4)	(0)	(2)	(0)	(1)	(1)	(1)
36	Underground	PUL	(41)	(31)	(1)	(30)	(0)	(10)	(8)	(3)	(5)	(0)	(2)	(0)	(0)	(1)	(0)
37	Total		(60)	(42)	(2)	(41)	(0)	(17)	(13)	(4)	(9)	(0)	(4)	(1)	(1)	(2)	(1)
38	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	**Net Inv Tax Credit**		(180)	(88)	(4)	(84)	(0)	(91)	(62)	(11)	(50)	(1)	(29)	(6)	(11)	(13)	(1)
41	**Total Operating Exp**		170,285	65,856	3,437	62,181	238	102,872	66,909	9,648	55,936	1,325	35,963	6,624	14,353	14,986	1,557
42A	**Pres Op Inc Before Inc Tax**		11,032	5,015	340	4,706	(31)	6,001	5,632	641	4,720	272	369	(55)	894	(470)	15
42B	**Prop Op Inc Before Inc Tax**		29,615	13,471	716	12,758	(3)	15,931	12,465	1,829	10,214	422	3,466	487	2,089	890	213

Tax Deprec; Inc Tax & Return

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential					Small Comm & Indus				Large Comm & Indus			
	Production	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Peaking Plant	D10C	9,215	3,552	140	3,396	16	5,640	3,739	505	3,159	75	1,901	351	714	836	23
2	Nuclear Fuel	D8760	4,928	1,656	97	1,552	7	3,245	2,068	258	1,768	42	1,177	215	483	479	27
3	Base Load	D8760	14,629	4,915	289	4,607	20	9,634	6,140	766	5,249	125	3,494	639	1,433	1,423	80
4	Total		28,773	10,123	526	9,555	43	18,520	11,947	1,529	10,177	241	6,573	1,206	2,629	2,738	130
	Transmission																
5	Gen Step Up Base	D8760	16	5	0	5	0	11	7	1	6	0	4	1	2	2	0
6	Gen Step Up Peak	D10C	19	7	0	7	0	12	8	1	7	0	4	1	1	2	0
7	Total Gen Step Up		35	13	1	12	0	22	14	2	12	0	8	1	3	3	0
8	Bulk Transmission	D10T	6,120	2,441	123	2,307	11	3,653	2,410	317	2,045	49	1,242	230	470	542	27
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total		6,155	2,453	124	2,319	11	3,675	2,425	319	2,057	49	1,250	232	473	545	27
	Distribution																
12	Generat Step Up	STRATH	8	3	0	3	0	5	3	0	3	0	2	0	1	1	0
13	Bulk Transmission	D10T	4	2	0	2	0	2	2	0	1	0	1	0	0	0	0
14	Distrib Function	D60Sub	196	81	5	76	0	113	72	10	61	1	41	8	15	18	2
15	Direct Assign	Dir Assign	2	0	0	0	0	2	0	0	0	0	2	0	1	1	0
16	Total Substations		210	85	5	80	0	123	77	11	65	2	45	8	17	20	2
17	Overhead Lines	POL	2,059	1,215	45	1,168	2	754	539	130	401	7	215	46	67	102	90
18	Underground	PUL	3,894	2,959	121	2,835	2	914	767	304	460	4	147	41	25	81	21
19	Line Transformers	P68	380	252	11	240	0	125	102	26	77	0	23	8	2	14	2
20	Services	P69	(420)	(370)	(16)	(354)	(0)	(50)	(45)	(20)	(26)	0	(5)	(1)	0	(3)	0
21	Meters	C12WM	245	155	6	148	1	88	76	51	20	5	13	0	1	12	2
22	Street Lighting	P73	115	0	0	0	0	0	0	0	0	0	0	0	0	0	115
23	Total		6,483	4,296	174	4,117	6	1,955	1,516	501	998	17	439	102	111	225	232
24	**General Plant**	PTD	1,243	551	26	523	2	679	450	71	370	8	229	43	88	98	13
25	**Electric Common**	PTD	1,365	605	29	574	2	745	494	78	407	9	251	47	96	108	14
26	**TBT Defer Inc Tax**	NEPIS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	**Total Tax Deprec**		44,018	18,029	878	17,088	63	25,573	16,832	2,499	14,008	325	8,741	1,630	3,397	3,714	416
28	Interest Expense		9,073	4,092	205	3,875	12	4,893	3,242	534	2,647	61	1,650	311	636	704	88
29	Other Tax Timing Differ		(1,399)	(558)	(28)	(527)	(2)	(835)	(551)	(72)	(467)	(11)	(284)	(53)	(107)	(124)	(6)
30	Total Tax Deductions		51,692	21,563	1,055	20,435	72	29,631	19,523	2,960	16,188	375	10,108	1,888	3,926	4,294	499
	Inc Tax Additions																
31	Book Depreciation		21,470	9,488	451	9,007	30	11,714	7,775	1,254	6,371	150	3,939	738	1,503	1,698	268
32	Deferred Inc Tax & ITC		4,819	1,934	89	1,838	7	2,859	1,895	277	1,582	36	964	180	370	414	25
33	Nuclear Fuel Book Burn	E8760	4,095	1,376	81	1,289	6	2,697	1,719	214	1,469	35	978	179	401	398	22
34	Nuclear Fuel Disposal	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Meals & Entertainment	LABOR	(112)	(47)	(2)	(45)	(0)	(63)	(42)	(7)	(34)	(1)	(21)	(4)	(8)	(9)	(2)
36	Avoided Tax Interest	RTBASE	2,707	1,221	61	1,156	4	1,460	967	159	790	18	492	93	190	210	26
37	Total Tax Additions		35,278	14,991	729	14,213	50	19,922	13,147	2,030	10,863	254	6,775	1,265	2,618	2,892	364
38	**Total Inc Tax Adjustments**		(16,415)	(6,571)	(327)	(6,222)	(23)	(9,709)	(6,376)	(930)	(5,325)	(121)	(3,333)	(623)	(1,308)	(1,402)	(135)
39A	**Pres Taxable Net Income**		(5,382)	(1,556)	13	(1,516)	(53)	(3,707)	(743)	(290)	(604)	151	(2,964)	(677)	(414)	(1,873)	(119)
39B	**Prop Taxable Net Income**		13,200	6,899	389	6,536	(26)	6,222	6,089	899	4,889	301	134	(135)	781	(512)	79
40A	Pres Fed & State Inc Tax		(2,384)	(689)	6	(671)	(24)	(1,642)	(329)	(128)	(268)	67	(1,313)	(300)	(183)	(829)	(53)
40B	Prop Fed & State Inc Tax		4,120	2,153	121	2,040	(8)	1,942	1,900	280	1,526	94	42	(42)	244	(160)	25
41A	Pres Preliminary Return	(total); BASE	13,416	5,704	334	5,378	(7)	7,643	5,962	769	4,988	205	1,682	245	1,077	359	68
41B	Prop Preliminary Return	(total); BASE	25,495	11,317	594	10,718	5	13,989	10,564	1,549	8,688	328	3,425	529	1,845	1,050	189
42	Total AFUDC		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43A	**Present Total Return**		13,416	5,704	334	5,378	(7)	7,643	5,962	769	4,988	205	1,682	245	1,077	359	68
43B	**Proposed Total Return**		25,495	11,317	594	10,718	5	13,989	10,564	1,549	8,688	328	3,425	529	1,845	1,050	189
44A	**Pres % Return on Rate Base**		4.75%	4.48%	5.23%	4.46%	-1.87%	5.01%	5.90%	4.62%	6.05%	10.77%	3.27%	2.54%	5.44%	1.64%	2.47%
44B	**Prop % Return on Rate Base**		9.02%	8.88%	9.31%	8.88%	1.23%	9.18%	10.46%	9.31%	10.53%	17.23%	6.66%	5.47%	9.32%	4.79%	6.85%
45A	**Present Common Return**		4,343	1,613	129	1,503	(19)	2,751	2,720	235	2,340	144	31	(65)	442	(345)	(20)
45B	**Proposed Common Return**		16,422	7,225	389	6,844	(7)	9,096	7,322	1,015	6,040	267	1,774	219	1,209	346	100
46A	**Pres % Ret on Common Rate Base**		2.98%	2.45%	3.91%	2.41%	-9.85%	3.50%	5.22%	2.74%	5.50%	14.64%	0.12%	-1.31%	4.32%	-3.05%	-1.43%
46B	**Prop % Ret on Common Rate Base**		11.25%	10.98%	11.81%	10.98%	-3.84%	11.56%	14.04%	11.82%	14.19%	27.16%	6.68%	4.38%	11.83%	3.05%	7.06%

	Allow For Funds Used During Constr		1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential					Small Comm & Indus				Large Comm & Indus			
	Production	**Alloc**	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Base Load	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Total		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission																
5	Gen Step Up Base	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution																
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Total		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	**Total AFUDC**		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Labor Allocator																
	Production																
27	Other Prod - Cap	OXOPD	6,170	2,241	106	2,125	10	3,905	2,542	331	2,160	51	1,363	251	535	578	24
28	Other Prod - Ene	E8760	5,039	1,693	99	1,587	7	3,318	2,115	264	1,808	43	1,204	220	494	490	28
29	Total		11,209	3,934	206	3,712	17	7,224	4,657	595	3,968	94	2,567	471	1,028	1,068	51
	Transmission																
30	Stepup Subtrans	P5161A	19	7	0	7	0	12	8	1	7	0	4	1	2	2	0
31	Bulk Power Subs	D10T	669	267	13	252	1	399	263	35	224	5	136	25	51	59	3
32	Total		688	274	14	259	1	411	271	36	230	5	140	26	53	61	3
	Distribution																
33	Superv & Eng	ZDTS	494	294	12	281	1	174	128	39	86	2	46	9	14	23	27
34	Load Dispatch	D10T	192	77	4	72	0	115	76	10	64	2	39	7	15	17	1
35	Substation	P61	200	82	5	77	0	116	73	10	62	1	43	8	16	19	2
36	Overhead Lines	POL	575	339	13	326	1	211	150	36	112	2	60	13	19	28	25
37	Underground Lines	PUL	672	511	21	489	0	158	132	52	79	1	25	7	4	14	4
38	Line Transformer	P68	5	3	0	3	0	2	1	0	1	0	0	0	0	0	0
39	Meter	C12WM	209	132	5	126	1	75	65	43	17	4	11	0	0	10	2
40	Cust Installation	ZDTS	112	67	3	64	0	39	29	9	20	1	10	2	3	5	6
41	Street Lighting	P73	65	0	0	0	0	0	0	0	0	0	0	0	0	0	65
42	Miscellaneous	OXDTS	277	162	7	155	0	95	69	20	48	1	26	5	8	12	20
43	Total		2,801	1,666	69	1,594	3	984	724	220	490	14	260	52	79	129	151
44	**Cust Accounting**	C11WA	746	594	23	570	1	145	140	91	48	1	5	0	0	5	6
45	**Sales Expense**	C11P10	2	1	0	1	0	1	1	0	0	0	0	0	0	0	0
46	**Admin & General**	LABOR	5,594	2,352	113	2,231	8	3,166	2,093	342	1,710	41	1,073	198	419	456	76
47	**Service & Inform**	C11P10	137	82	4	79	0	53	37	10	27	1	16	3	6	7	2
48	**Labor**		21,177	8,905	429	8,446	30	11,983	7,923	1,294	6,473	156	4,061	750	1,586	1,725	289

Backwards Revenue Calc

		1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
				Residential					Small Comm & Indus				Large Comm & Indus			
	(1A) Modified Pres Rev	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Present Preliminary Return (Before AFUDC)	13,416	5,704	334	5,378	(7)	7,643	5,962	769	4,988	205	1,682	245	1,077	359	68
2	1/(1-T) Rev Reqt (= 1.7950)	24,081	10,239	599	9,653	(13)	13,720	10,701	1,380	8,953	368	3,019	440	1,934	645	122
3	Total Inc Tax Adjustments	(16,415)	(6,571)	(327)	(6,222)	(23)	(9,709)	(6,376)	(930)	(5,325)	(121)	(3,333)	(623)	(1,308)	(1,402)	(135)
4	T/(1-T) Rev Reqt (= 0.7950)	(13,049)	(5,224)	(260)	(4,947)	(18)	(7,718)	(5,069)	(740)	(4,233)	(96)	(2,650)	(495)	(1,040)	(1,115)	(107)
5	Tot Op Exp W/o Regul Exp	169,959	65,726	3,430	62,058	238	102,679	66,779	9,629	55,828	1,322	35,900	6,612	14,326	14,961	1,554
6	- Other Retail Rev W/o Gr Earn, Etc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	- Other Op Rev W/o Late Pay, Etc.	34,579	12,266	679	11,537	50	22,123	14,227	1,822	12,117	287	7,896	1,449	3,183	3,265	190
8	Modified Pres Net Oper Exp	135,380	53,460	2,751	50,521	188	80,556	52,553	7,807	43,711	1,034	28,003	5,164	11,143	11,696	1,364
9	**Mod Pres Rev (R02) (component alloc)**	146,412	58,475	3,091	55,227	157	86,557	58,185	8,448	48,431	1,306	28,372	5,109	12,037	11,226	1,379
	(1B) Present Revenue															
10	Tot Oper Exp (w/ Regul Exp)	170,285	65,856	3,437	62,181	238	102,872	66,909	9,648	55,936	1,325	35,963	6,624	14,353	14,986	1,557
11	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	- Other Oper Rev (w/ Late Pay, Etc)	34,933	12,407	686	11,670	51	22,332	14,367	1,843	12,234	290	7,965	1,461	3,212	3,292	193
13	Net Oper Exp Rev Reqt	135,352	53,449	2,750	50,511	188	80,540	52,542	7,805	43,702	1,034	27,998	5,163	11,141	11,694	1,364
14	**Tot Pres Rate Rev Reqt (R01)**	146,384	58,464	3,090	55,217	157	86,541	58,174	8,446	48,422	1,306	28,367	5,108	12,035	11,224	1,379
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	(2) Proposed Return															
15	Total Operating Exp	170,285	65,856	3,437	62,181	238	102,872	66,909	9,648	55,936	1,325	35,963	6,624	14,353	14,986	1,557
16	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	- Prop Other Operating Rev	35,044	12,452	689	11,712	51	22,398	14,411	1,849	12,271	291	7,987	1,465	3,221	3,301	194
18	Prop Net Oper Exp Rev Reqt	135,241	53,404	2,748	50,469	187	80,474	52,497	7,799	43,665	1,033	27,977	5,159	11,132	11,686	1,363
19	Prop Preliminary Return	25,495	11,317	594	10,718	5	13,989	10,564	1,549	8,688	328	3,425	529	1,845	1,050	189
20	1/(1-T) Rev Reqt (= 1.4537)	37,063	16,452	864	15,581	7	20,336	15,358	2,251	12,630	477	4,979	770	2,682	1,527	274
21	T/(1-T) Rev Reqt (= 0.4537)	(7,448)	(2,982)	(148)	(2,823)	(10)	(4,405)	(2,893)	(422)	(2,416)	(55)	(1,512)	(282)	(593)	(636)	(61)
22	**Total Proposed Rate Rev Reqt**	164,856	66,875	3,464	63,227	184	96,405	64,962	9,628	53,879	1,455	31,443	5,646	13,221	12,576	1,576
	(3) Equal Return Rev															
23	T/(1-T) Rev Reqt (= 0.4537)	(7,448)	(2,982)	(148)	(2,823)	(10)	(4,405)	(2,893)	(422)	(2,416)	(55)	(1,512)	(282)	(593)	(636)	(61)
24	Equal Net Oper Exp Rev Reqt	135,241	53,404	2,748	50,469	187	80,474	52,497	7,799	43,665	1,033	27,977	5,159	11,132	11,686	1,363
25	Equal Rate of Ret (9.02%) x Rate Base	25,494	11,498	576	10,887	34	13,748	9,110	1,500	7,439	172	4,638	873	1,786	1,979	248
26	- AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Net Return	25,494	11,498	576	10,887	34	13,748	9,110	1,500	7,439	172	4,638	873	1,786	1,979	248
28	1/(1-T) Rev Reqt (= 1.7950)	37,062	16,715	838	15,827	50	19,986	13,244	2,180	10,814	250	6,742	1,268	2,597	2,877	361
29	**Net Equal-Ret Rate Rev-Reqt (R99)**	164,855	67,137	3,438	63,473	227	96,055	62,849	9,557	52,064	1,228	33,206	6,145	13,135	13,926	1,663
30	Tot Oper Rev - Equal	199,899	79,589	4,126	75,185	278	118,453	77,260	11,406	64,335	1,519	41,193	7,610	16,356	17,227	1,857
31	- Total Operating Exp	170,285	65,856	3,437	62,181	238	102,872	66,909	9,648	55,936	1,325	35,963	6,624	14,353	14,986	1,557
32	Equal Op Inc Before Inc Tax	29,614	13,733	689	13,004	39	15,581	10,351	1,758	8,398	195	5,230	986	2,003	2,240	300
33	Equal Taxable Net Income	13,199	7,162	363	6,782	17	5,872	3,975	828	3,074	74	1,897	363	695	838	166
34	Equal Fed & State Inc Tax	4,120	2,235	113	2,117	5	1,833	1,241	258	959	23	592	113	217	262	52
35	Proposed Common Return	16,421	7,406	371	7,013	22	8,855	5,868	966	4,792	111	2,987	562	1,151	1,275	160
36	Equal Return on Common	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%	11.25%

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential						Small Comm & Indus				Large Comm & Indus		
INTERNAL ALLOCATORS		Intern:	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	**Rate Base: Col %'s**	**BASE-COL**	**1100.000%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
			100.000%														
2	50% Cus, 50% Prod Plt	C11P10	100.000%	60.134%	2.598%	57.363%	0.173%	38.447%	26.902%	7.014%	19.439%	0.449%	11.545%	2.109%	4.603%	4.834%	1.419%
3	Peaking Plant Capacity	D10C	100.000%	38.543%	1.515%	36.856%	0.172%	61.207%	40.573%	5.483%	34.282%	0.809%	20.634%	3.813%	7.744%	9.076%	0.250%
4	100% Sum/Win Dmd, 0% Ene	D100E0	100.000%	36.731%	0.846%	35.719%	0.166%	63.269%	42.186%	5.898%	35.457%	0.831%	21.083%	3.878%	7.831%	9.374%	0.000%
5	61% Sum/Win Dmd, 39% Ene	D48E52	100.000%	36.599%	1.991%	34.453%	0.156%	62.907%	40.733%	5.206%	34.703%	0.824%	22.174%	4.080%	8.785%	9.309%	0.494%
6	Labor w/o (or w/) A&G	LABOR	100.000%	42.048%	2.025%	39.882%	0.141%	56.586%	37.410%	6.109%	30.565%	0.736%	19.176%	3.541%	7.488%	8.147%	1.366%
7	Net Plant In Service	NEPIS	100.000%	46.008%	2.269%	43.605%	0.134%	53.099%	35.323%	5.915%	28.749%	0.659%	17.776%	3.355%	6.795%	7.626%	0.893%
8	Dis O&M w/o Sup & Misc	OXDTS	100.000%	58.597%	2.386%	56.105%	0.106%	34.249%	25.004%	7.135%	17.459%	0.410%	9.244%	1.903%	2.830%	4.511%	7.154%
9	Other Prod Capac O&M	OXOPD	100.000%	36.321%	1.721%	34.443%	0.156%	63.295%	41.200%	5.371%	35.000%	0.829%	22.096%	4.063%	8.666%	9.367%	0.384%
10	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	100.000%	37.497%	2.006%	35.351%	0.139%	61.639%	39.905%	5.620%	33.491%	0.795%	21.733%	3.988%	8.749%	8.995%	0.864%
11	Production Plant	P10	100.000%	35.036%	1.841%	33.048%	0.147%	64.503%	41.562%	5.306%	35.416%	0.840%	22.941%	4.207%	9.199%	9.536%	0.461%
12	Total P51 & P61A	P5161A	100.000%	36.222%	1.731%	34.336%	0.155%	63.389%	41.228%	5.366%	35.032%	0.829%	22.161%	4.074%	8.707%	9.380%	0.390%
13	Distribution Plant	P60	100.000%	64.733%	2.759%	61.870%	0.104%	32.815%	24.225%	6.873%	17.032%	0.320%	8.590%	1.842%	2.525%	4.223%	2.452%
14	Distr Substn Plant	P61	100.000%	40.973%	2.345%	38.458%	0.169%	58.132%	36.683%	5.120%	30.817%	0.747%	21.449%	3.962%	7.906%	9.581%	0.895%
15	Line Transformer Plant	P68	100.000%	66.390%	3.012%	63.255%	0.123%	32.999%	26.926%	6.718%	20.163%	0.045%	6.073%	2.038%	0.448%	3.587%	0.611%
16	Services Plant	P69	100.000%	88.047%	3.716%	84.251%	0.079%	11.953%	10.824%	4.732%	6.092%	0.000%	1.130%	0.316%	0.000%	0.814%	0.000%
17	Dist Plt Overhead Lines	POL	100.000%	59.008%	2.206%	56.704%	0.098%	36.609%	26.159%	6.330%	19.490%	0.339%	10.451%	2.246%	3.257%	4.948%	4.383%
18	Real Est & Property Tax	PT0	100.000%	44.874%	2.148%	42.582%	0.144%	54.027%	36.128%	5.967%	29.473%	0.688%	17.899%	3.390%	6.751%	7.757%	1.099%
19	Produc, Trans & Distrib	PTD	100.000%	44.349%	2.131%	42.080%	0.138%	54.613%	36.212%	5.746%	29.784%	0.682%	18.401%	3.458%	7.047%	7.896%	1.038%
20	Dist Plt Undground Lines	PUL	100.000%	75.980%	3.119%	72.803%	0.058%	23.483%	19.708%	7.802%	11.815%	0.091%	3.775%	1.061%	0.644%	2.071%	0.537%
21	**Rev w/o Reg, etc: Col %**	**R02-COL**	**1100.000%**	**N/A**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
			100.000%	**42.52%**	**2.49%**	**40.08%**	**-0.05%**	**56.97%**	**44.44%**	**5.73%**	**37.18%**	**1.53%**	**12.53%**	**1.83%**	**8.03%**	**2.68%**	**0.51%**
			100.000%	**44.39%**	**2.33%**	**42.04%**	**0.02%**	**54.87%**	**41.44%**	**6.07%**	**34.08%**	**1.29%**	**13.43%**	**2.08%**	**7.24%**	**4.12%**	**0.74%**
22	Rate Base (Non-Column)	RTBASE	100.000%	45.099%	2.260%	42.705%	0.134%	53.926%	35.735%	5.882%	29.180%	0.673%	18.191%	3.422%	7.007%	7.762%	0.974%
23	Stratified Hydro Baseload	STRATH	100.000%	34.985%	1.845%	32.993%	0.147%	64.550%	41.576%	5.304%	35.432%	0.840%	22.974%	4.212%	9.219%	9.542%	0.464%
24	Transmission & Distrib	TD	100.000%	56.754%	2.517%	54.111%	0.127%	41.439%	29.085%	6.332%	22.282%	0.471%	12.354%	2.460%	4.182%	5.713%	1.807%
25	Labor Dis w/o Sup & Eng	ZDTS	100.000%	59.495%	2.466%	56.910%	0.119%	35.127%	25.837%	7.857%	17.487%	0.493%	9.290%	1.852%	2.821%	4.617%	5.378%

			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	35=36 to 38
					Residential						Small Comm & Indus				Large Comm & Indus		
INTERNAL DATA			**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
26	Labor w/o A&G	LABOR(S)	15,583	6,552	316	6,215	22	8,818	5,830	952	4,763	115	2,988	552	1,167	1,270	213
27	Dis O&M w/o Sup, Cust Install & Misc	OXDTS	4,105	2,406	98	2,303	4	1,406	1,026	293	717	17	380	78	116	185	294
28	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	135,247	50,713	2,713	47,811	189	83,364	53,971	7,601	45,295	1,075	29,393	5,394	11,833	12,166	1,169
29	Total P51 & P61A	P5161A	2,464	893	43	846	4	1,562	1,016	132	863	20	546	100	215	231	10
30	Produc, Trans & Distrib	PTD	600,181	266,172	12,788	252,553	831	327,778	217,337	34,486	178,758	4,092	110,441	20,752	42,297	47,393	6,231
31	Transmission & Distrib	TD	257,359	146,062	6,477	139,258	327	106,646	74,852	16,295	57,344	1,213	31,794	6,330	10,762	14,702	4,650
32	Labor Dis w/o Sup & Eng, Cust Install	ZDTS	2,195	1,306	54	1,249	3	771	567	172	384	11	204	41	62	101	118

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dako1a
Pro forma Year
Comparison Class Cost of Service Detail

(Comm / Indus By Size)

Docket No. EL09-____
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Schedule 5
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			1=2+6+9+10	2=3 to 5	3	4	5	6=7+8	12=13 to 16	13	14	15	17=18 to 21	18	19	21	
				Residential						Small Comm & Indus				Large Comm & Indus			
	EXTERNAL ALLOCATORS	Extern:	**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Customers - Ave Monthly	C11	100.00%	85.23%	3.35%	81.68%	0.20%	12.39%	12.24%	8.72%	3.46%	0.06%	0.15%	0.01%	0.01%	0.13%	2.38%
2	Cust Acctg Wtg Factor	C11WA	100.00%	79.70%	3.14%	76.46%	0.09%	19.50%	18.84%	12.25%	6.48%	0.11%	0.66%	0.03%	0.02%	0.62%	0.80%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	63.11%	2.48%	60.30%	0.33%	36.05%	30.95%	20.75%	8.24%	1.96%	5.10%	0.04%	0.22%	4.85%	0.84%
4	Sec & Pri Customers	C61PS	100.00%	86.89%	3.43%	83.46%	0.00%	12.66%	12.51%	8.91%	3.54%	0.06%	0.15%	0.01%	0.01%	0.13%	0.45%
5	C62Sec, w/o Ltg & C/I Underground	C62NL	100.00%	92.62%	3.65%	88.97%	0.00%	7.38%	7.30%	5.22%	2.07%	0.00%	0.08%	0.01%	0.00%	0.07%	0.00%
6	Secondary Customers	C62Sec	100.00%	86.95%	3.43%	83.52%	0.00%	12.59%	12.46%	8.92%	3.54%	0.00%	0.14%	0.01%	0.00%	0.13%	0.45%
7	Summer Peak Resp KW	D10S	100.00%	36.73%	0.85%	35.72%	0.17%	63.27%	42.19%	5.90%	35.46%	0.83%	21.08%	3.88%	7.83%	9.37%	0.00%
8	Transmission Demand %	D10T	100.00%	39.88%	2.01%	37.70%	0.18%	59.68%	39.38%	5.18%	33.41%	0.79%	20.30%	3.77%	7.68%	8.86%	0.43%
9	Winter Peak Resp KW	D10W	100.00%	43.97%	3.52%	40.26%	0.19%	55.03%	35.74%	4.24%	30.76%	0.74%	19.29%	3.62%	7.48%	8.18%	1.00%
10	Dmd Equiv of E8760	D8760	100.00%	33.60%	1.97%	31.49%	0.14%	65.85%	41.97%	5.23%	35.88%	0.85%	23.89%	4.37%	9.79%	9.72%	0.55%
11	Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	100.00%	41.33%	2.37%	38.79%	0.17%	57.76%	36.93%	5.16%	31.02%	0.75%	20.83%	3.99%	7.49%	9.35%	0.91%
12	Sec & Pri, Cl Coin kW (no Min Sys; adj	D61PS	100.00%	36.57%	0.82%	35.58%	0.17%	62.57%	39.35%	4.56%	33.96%	0.83%	23.22%	4.45%	8.36%	10.41%	0.86%
13	D62Sec, w/o Ltg & C/I Underground	D62NLL	100.00%	76.45%	3.87%	72.30%	0.28%	23.55%	19.76%	3.48%	16.28%	0.00%	3.79%	1.10%	0.00%	2.69%	0.00%
14	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	100.00%	53.49%	2.91%	50.37%	0.21%	45.80%	36.86%	5.23%	31.63%	0.00%	8.94%	3.36%	0.00%	5.58%	0.71%
15	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
16	On + Off Sales MWH	E8760	100.00%	33.60%	1.97%	31.49%	0.14%	65.85%	41.97%	5.23%	35.88%	0.85%	23.89%	4.37%	9.79%	9.72%	0.55%
17	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	Present Rev	R01	100.00%	39.94%	2.11%	37.72%	0.11%	59.12%	39.74%	5.77%	33.08%	0.89%	19.38%	3.49%	8.22%	7.67%	0.94%

	APPLIED EXTERNAL DATA (BIG or LITTLE)		**MN**	**Res Tot**	**Res W/**	**Res W/o**	**Ld Mgmt**	**C&I Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Interrupt**	**Ltg Tot**
1	Customers - B Basis	C10	80,421	69,876	2,757	67,120	0	10,182	10,060	7,167	2,845	48	122	9	5	108	363
2	Cust - Ave Monthly (C10-Area Lt)	C11	82,176	70,041	2,757	67,120	164	10,182	10,060	7,167	2,845	48	122	9	5	108	1,954
3	Mo Cus Wtd By Cus Acct	C11WA	87,780	69,958	2,757	67,120	82	17,118	16,536	10,751	5,690	95	582	26	16	540	703
4	Cust Acctg Wtg Factor	C11WAF	31.60	2.50	1.00	1.00	0.50	22.50	8.50	1.50	2.00	2.00	14.00	3.00	3.00	5.00	3.10
5	Cust-Ave Mo (C11 w/ Dir Assign St Ltg	C12	80,483	70,041	2,757	67,120	164	10,182	10,060	7,167	2,845	48	122	9	5	108	261
6	Mo Cus Wtd By Mtr Invest	C12WM	8,621,316	5,440,637	213,503	5,198,742	28,392	3,108,010	2,668,017	1,788,808	710,074	169,136	439,992	3,183	18,661	418,148	72,669
7	Meter Invest / Cust Factor	C12WMF	19,809	328	77	77	173	18,953	7,608	250	250	3,555	11,345	367	3,555	3,869	278
8	Sec & Pri Customers	C61PS	80,421	69,876	2,757	67,120	0	10,182	10,060	7,167	2,845	48	122	9	5	108	363
9	C62Sec, w/o Ltg & C/I Underground	C62NL	75,443	69,876	2,757	67,120	0	5,567	5,507	3,942	1,565	0	60	5	0	55	0
10	Secondary Customers	C62Sec	80,361	69,876	2,757	67,120	0	10,121	10,012	7,167	2,845	0	109	9	0	101	363
11	Summer Peak Resp KW	D10S	423,265	155,471	3,581	151,188	702	267,795	178,558	24,964	150,076	3,518	89,237	16,415	33,146	39,676	0
12	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,988,085	200,895	3,769,619	17,572	5,968,419	3,938,256	517,567	3,341,389	79,300	2,030,163	376,561	768,026	885,576	43,496
13	Winter Peak Resp KW	D10W	330,119	145,149	11,615	132,913	622	181,670	117,999	13,991	101,553	2,454	63,672	11,948	24,708	27,015	3,300
14	Dmd Equiv of E20	D20	**2,634,418,636**	864,801,521	48,785,851	812,441,830	3,573,840	1,754,583,583	###########	137,734,597	955,254,248	22,631,257	638,963,481	106,969,383	275,583,392	256,410,706	15,033,531
15	Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	508,932	210,336	12,046	197,421	869	293,984	187,958	26,253	157,878	3,826	106,026	20,317	38,140	47,569	4,612
16	Sec & Pri, Class Coin kW (w/o Min Sys	D61PS	455,906	166,721	3,735	162,216	770	285,277	179,407	20,806	154,813	3,788	105,870	20,299	38,132	47,440	3,909
17	D62Sec, w/o Ltg & C/I Underground	D62NLL	732,258	559,811	28,365	529,390	2,056	172,446	144,686	25,501	119,185	0	27,761	8,056	0	19,704	0
18	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	401,594	173,373	10,387	162,216	770	224,312	175,619	20,806	154,813	0	48,693	20,299	0	28,394	3,909
19	Annual Billing kW	D99	3,059,299	0	0	0	0	3,059,299	2,025,150	0	1,966,057	59,092	1,034,149	167,901	372,394	493,854	0
20	Summer Billing kW	D99S	1,117,880	0	0	0	0	1,117,880	733,515	0	713,765	19,749	384,365	55,342	143,234	185,788	0
21	Winter Billing kW	D99W	1,941,419	0	0	0	0	1,941,419	1,291,635	0	1,252,292	39,343	649,784	112,558	229,160	308,066	0
22	Non-Coinc Pk Second	DN-Sec	877,259	559,811	28,365	529,390	2,056	313,539	263,065	46,365	216,700	0	50,474	14,648	0	35,826	3,909
23	Energy At Gener kWh	E10	2,012,123,191	675,264,938	38,552,183	633,944,247	2,768,508	1,323,322,091	836,575,438	102,180,421	717,284,765	17,110,253	486,746,653	81,549,394	212,225,824	192,971,435	13,536,161
24	On Peak Wtg Factor %	E11	NA	NA	35.28%	37.42%	38.66%	89.94%	133.23%	46.25%	44.10%	42.89%	124.80%	41.43%	39.68%	43.69%	44.11%
25	Wtd On + Off Sales kWh	E20	2,634,418,636	864,801,521	48,785,851	812,441,830	3,573,840	1,754,583,583	###########	137,734,597	955,254,248	22,631,257	638,963,481	106,969,383	275,583,392	256,410,706	15,033,531
26	kWh Sales @ Gen	E99	1,942,542,005	640,055,427	36,850,000	600,607,563	2,597,864	1,289,498,152	809,966,570	99,006,841	691,963,250	18,996,479	479,531,581	82,233,935	209,323,478	187,974,169	12,988,427

ALLOCATOR CONSTANTS

			1993 Values	
1	On Peak Energy Wtg Factor For E20	ONPKWF		**1.752**
2	APL Inv In OH Lines: Dir Assignable	**POLAPL**		78
3	Summer Factor	SFAC	0.5811	0.7497
4	Overhead Lines St Ltg Comp Owned	**QQOSL1**	2.475%	2.440%
5	Overhead Lines Area Lighting	**QQOSL2**	1.150%	1.133%
6	Overhead Lines Primary - Customer	**QQ64C**	30.312%	25.957%
7	Overhead Lines Primary - Demand	**QQ64D**	34.399%	38.992%
8	Overhead Lines Secondary - Customer	**QQ65C**	15.632%	16.335%
9	Overhead Lines Secondary - Demand	**QQ65D**	16.032%	15.143%
10	Overhead Total		100.000%	100.000%
11	Underground Primary - Customer	**QQ66C**	27.223%	46.101%
12	Underground Primary - Demand	**QQ66D**	29.550%	7.659%
13	Underground Secondary - Customer	**QQ67C**	16.338%	25.067%
14	Underground Secondary - Demand	**QQ67D**	26.889%	21.173%
15	Underground Total		100.000%	100.000%
16	Line Trans Secondary - Customer	**QQ68C**	36.255%	41.260%
17	Line Trans Secondary - Demand	**QQ68D**	58.497%	53.380%
18	Line Trans Primary - Demand	**QQ68P**	5.248%	5.360%
19	Line Trans Total		100.000%	100.000%
20	Services - Customer	**QQ69C**	84.327%	71.710%
21	Services - Demand	**QQ69D**	15.673%	28.290%
22	Services Total		100.000%	100.000%
23	Stratified Nuclear Baseload (JCOSS or	**STRNBL**		0.8142
24	Stratified Fossil Baseload (JCOSS only	**STRFBL**		0.6728
25	Stratified Hydro Baseload	**STRHBL**		0.7197

CALCULATED CONSTANTS

26	Net Overhead Lines Investment	**QPOLS**	42,201
27	Ovhd Lines St Ltg Co - Assignable	**QQSL1**	1,030
28	Ovhd Lines Area Ltg - Assignable	**QQSL2**	478
29	Ovhd St Lt + Area Lt + Dir Assign	**QQSLTOT**	1,586
30	**Peaking Factor For Purchased Power**		0.550

				Tax Rates Without Any Credits	
31	Total Proposed Retail Revenue		164,855		
32	Ratio: Prop vs Pres Retail Revenue		1.1262	**State Rate**	**Effective Fed Rate**
33	State Tax Rate		0.00%	0.00%	35.00%
34	State Tax Credit		0		
35	Federal Tax Rate		35.00%		
36	Federal Tax Credit		500		
37	Present Taxable Income		(5,382)		
38	Proposed Taxable Income		13,200		
39	Present State Credit %		0.000%		
40	Present Federal Credit %		-9.289%		
41	Proposed State Credit %		0.000%		
42	Proposed Federal Credit %		3.788%		
43	Pres Combined State & Fed Tax Rate	**TAXRATE**	44.29%		

	Capital Structure	**Cost**	**Ratio**	**Wtd Cost**
44	Long Term Debt	6.64%	48.37%	3.21%
45	Short Term Debt	0.00%	0.00%	0.00%
46	Preferred Stock	0.00%	0.00%	0.00%
47	Equity	11.25%	51.63%	5.81%

CALCULATED CONSTANTS

48	Proposed Overal Return			9.020%
49	Interest Exp Factor	**DETFACT**		3.2100%
50	Debt Ratio	**DETRATIO**		48.37000%
51	Embedded Cost of Debt	**DETCOST**		6.6400%
54	Rev Increase Percent	INCRPCT		12.6189%
55	1 / (1 - Tax Rate) Factor	**ONEOVER**	Present	179.4992%
56	Tax Rate / (1 - Tax Rate) Factor	**TAXOVER**	Present	79.4992%
57	1 / (1 - Tax Rate) Factor	**ONEOVER**	Proposed	145.3747%
58	Tax Rate / (1 - Tax Rate) Factor	**TAXOVER**	Proposed	45.3747%

VOLTAGE DISCOUNT ANALYSIS - DEMAND ($/kW)

Includes losses to indicate additional billing kW low voltage customers would have at higher voltage.

	Secondary Costs	Primary Costs	
	Lines & Transformers	Lines & Transformers	Distribution Substation
1. Revenue Requirement ($000s):			
(CCOSS; p. 2; lines 34,33,32)	$1,003.578	$2,124.250	$2,443.031
2. Billing KW (Workpaper attached)			
Secondary Voltage kW	2,459,593	2,459,593	2,459,593
Loss 1		0.9620	0.9821
* Demand Loss Factor		0.9422	0.9422
Loss Factor	1.0000	1.0210	1.0423
Secondary With Losses	**2,459,593**	**2,511,280**	**2,563,751**
Primary Voltage kW		599,706	599,706
Loss 1			0.9821
Loss 2			0.9620
Loss Factor		1.0000	1.0209
Primary With Losses		**599,706**	**612,236**
Transmission Transformed Voltage kW			**0**
Total kW (Metered Sales + Losses)	**2,459,593**	**3,110,986**	**3,175,987**
3. Rev Reqt / kW (Line 1 / Line 2)	$0.41	$0.68	$0.77
4. Cumulative Rev Reqt/ kW	$0.41	$1.09	$1.86
5. Present Individual Discounts	$0.80	$0.70	$0.55
6. Cumulative Present Discount	**$0.80**	**$1.50**	**$2.05**
7. Midpoint-Pres and Rev Reqt (Lines 4+ 6 /2)	$0.60	$1.30	$1.96
8. Cumulative Proposed Discount (Rounded to nearest $0.05)	**$0.80**	**$1.30**	**$2.00**

Demand loss factors from Load Research

Demand Component	Summer On-Peak	Winter On-Peak	Weighted Average *
Small Secondary	0.9309	0.9418	
Large Secondary	0.9417	0.9487	
Secondary Lines	0.9363	0.9452	0.9422
Primary Lines	0.9566	0.9647	0.9620
Primary Substations	0.9834	0.9814	0.9821
Transmission	0.9990	0.9972	0.9978

* Based on 4/12 Summer and 8/12 Winter.

Northern States Power Company, a Minnesota Corporation
Electric Utility - South Dakota
Test Year Ending December 31, 2008

Docket No. E-002/GR-08-1065
Exhibit No. _____(MAP-1)
Schedule 6
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VOLTAGE DISCOUNT ANALYSIS - ENERGY (¢/kWh)

Voltage	Loss Factor*	Percent Difference	Energy Charge	Cost-Based Discount	Proposed Discount	Present Discount
Secondary	0.9473	0.00%	**5.4130**	0.0000	0.0000	0.0000
Primary	0.9625	1.58%	5.3275	0.0855	0.0900	0.0600
T Transformed	0.9723	2.57%	5.2738	0.1392	0.1400	0.0900
Transmission	0.9842	3.75%	5.2101	0.2029	0.2000	0.1200

** 2008 South Dakota State Annual Energy Loss Factor*

Xcel Energy

Distributed Generation Interconnection Manual

Interconnection Process for Distributed Generation Systems

Interconnection Agreement
For the Interconnection of
Extended Parallel Distributed Generation Systems

Application to Interconnect Form

Engineering Data Submittal Form

Interconnection Requirements for Extended Paralleled Distribution Generation Systems

Version Date
September 14, 2007

Interconnection Process for Distributed Generation Systems

Introduction

This document has been prepared to explain the process established to interconnect a Generation System with the Xcel Energy (Company) electric distribution system. This document covers the interconnection process for all types of Generation Systems that are rated 10 MWs or less of total generation Nameplate Capacity; are planned for interconnection with the Company's distribution system; are not intended for wholesale transactions; and are not anticipated to affect the transmission system. This document does not discuss the interconnection Technical Requirements, which are covered in the **"**Interconnection Requirements for Extended Paralleled Distribution Generation Systems**"** document. This interconnection requirements document also provides definitions and explanations of the terms utilized within this document. To interconnect a Generation System with the Company, several steps must be followed. This document outlines those steps and the Parties' responsibilities. At any point in the process, if there are questions, please contact the Generation Interconnection Coordinator at the Company. Since this document has been developed to provide an interconnection process that covers a very diverse range of Generation Systems, the process may appear to be very involved and cumbersome. For many Generation Systems, the process is streamlined and provides an easy path for interconnection.

The promulgation of interconnection standards for Generation Systems must be done in the context of a reasonable interpretation of the boundary between state and federal jurisdiction. The Federal Energy Regulatory Commission (FERC) has asserted authority in the area, at least as far as interconnection at the transmission level is concerned. This, however, leaves open the question of jurisdiction over interconnection at the distribution level. The Midwest Independent System Operator's (MISO) FERC Electric Tariff, (first revised volume 1, August 23,2001) Attachment R (<u>Generator Interconnection Procedures and Agreement)</u> states in Section 2.1:

> "Any existing or new generator connecting at transmission voltages, sub-transmission voltages, or distribution voltages, planning to engage in the sale for resale of wholesale energy, capacity, or ancillary services requiring transmission service under the Midwest ISO OATT must apply to the Midwest ISO for interconnection service".

Further in Section 2.4 it states:

> "A Generator not intending to engage in the sale of wholesale energy, capacity, or ancillary services under the Midwest ISO OATT, that proposes to interconnect a new generating facility to the distribution system of a Transmission Owner or local distribution utility interconnected with the Transmission System shall apply to the Transmission Owner or local distribution utility for interconnection".

It goes on further to state:

> "Where facilities under the control of the Midwest ISO are affected by such interconnection, such interconnections may be subject to the planning and operating protocols of the Midwest ISO…."

Through discussions with MISO personnel and as a practical matter, if the Generation System Nameplate Capacity is not greater in size than the minimum expected load on the distribution substation that is feeding the proposed Generation System, and the Generation System's energy is not being sold on the wholesale market, then that installation may be considered as not "affecting" the transmission system and the interconnection may be considered to be governed by this process. If the Generation System will be selling energy on the wholesale market or the Generation System's total Nameplate Capacity is greater than the expected distribution substation's minimum load, then the Applicant shall contact MISO (Midwest Independent System Operator) and follow their procedures.

FERC has issued a rule for interconnecting generation facilities to distribution systems as part of their Small Generator Interconnection Procedures (SGIP). This rule covers facilities from 0 to 20 MW. If a distribution connected facility requires MISO involvement as discussed above, it probably will fall under FERC jurisdiction and will need to be interconnected under the FERC SGIP rules.

General Information

A) Definitions

1) <u>"Applicant"</u> is defined as the person or entity who is requesting the interconnection of the Generation System with the Company and is responsible for ensuring that the Generation System is designed, operated, and maintained in compliance with the Technical Requirements.

2) "Area EPS" is the area electric power system that is also referred to as the Company electric distribution system in this document.

3) "Company" is defined as an electric power system (EPS) that serves a Local EPS. Note: Typically, the Company has primary access to public rights-of-way, priority crossing of property boundaries, etc.

4) "Company Operator" is the entity or group who operates the Company's electric distribution system.

5) "Dedicated Facilities" is the equipment that is installed due to the interconnection of the Generation System and not required to serve other Company customers.

6) "Distribution System" is the Company facilities that are not part of the Company Transmission System or any Generation System.

7) "Extended Parallel" means the Generation System is designed to remain connected with the Company for an extended period.

8) "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.

9) "Generation Interconnection Coordinator" is the person or persons designated by the Company Operator to provide a single point of coordination with the Applicant for the generation interconnection process. For most installations, this is the Area Engineer assigned to the area of the proposed interconnection.

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

11) "Interconnection Customer" is the party or parties who will own/operate the Generation System and are responsible for meeting the requirements of the agreements and Technical Requirements. This could be the Generation System applicant, installer, owner, designer, or operator.

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

13) "Nameplate Capacity" is the total nameplate capacity rating of all the Generation included in the Generation System. For this definition, the "standby" and/or maximum rated kW capacity on the nameplate shall be used.

14) "Open Transfer" is a method of transferring the local loads from the Company to the generator such that the generator and the Company are never connected together.

15) "Point of Common Coupling" is the point where the Local EPS or Generation Facility is connected to the Company's distribution system.

16) "Quick Closed" is a method of generation transfer that parallels for less than 100 msec with the Company and has utility grade timers that limit the parallel duration to less then 100 msec with the Company.

17) "Quick Open" is a method of generation transfer that does not parallel with the Company and has a brief open interval, typically about 100 msec.

18) Soft Loading Transfer is a method of generation load transfer that parallels for typically less than 2 minutes to gradually transfer load between the generator and the Company.

19) "State" is the state wherein the interconnected generator is located.

20) "Technical Requirements" "is the Company "Interconnection Requirements for Extended Paralleled Distribution Generation Systems".

21) "Transmission System" means those facilities as defined by using the guidelines established by FERC.

B) Dispute Resolution

The following is the dispute resolution process to be followed for problems that occur with the implementation of this process.

Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably, and in a good faith manner. In the event a dispute arises under this process, and if it cannot be resolved by the Parties within thirty (30) days after written notice of the dispute to the other Party, the Parties shall submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in the same state as the Generation Facility location. The Parties agree to participate in good faith in the mediation for a period of 90 days. If the parties are not successful in resolving their disputes through mediation, then the Parties may refer the dispute for resolution to the Public Utilities Commission of the state in which the Generation Facility is located, which shall maintain continuing jurisdiction over this process. The rules of that state's PUC shall govern the dispute resolution.

C) Company Generation Interconnection Coordinator

Each Company Operator shall designate a Generation Interconnection Coordinator(s) and this person or persons shall provide a single point of contact for an Applicant's questions on this Generation Interconnection process. The Company Operator may have several Generation Interconnection Coordinators assigned, due to the geographical size of the electrical service territory or the amount of interconnection applications. This Generation Interconnection Coordinator will typically not be able to directly answer or resolve all of the issues involved in the review and implementation of the interconnection process and standards, but shall be available to provide coordination assistance with the Applicant. The Applicant is encouraged to discuss with or attend a pre-scoping meeting with the Coordinator to discuss potential difficulties, alternatives, and system compatibility issues before filing an application to interconnect.

D) Engineering Studies

During the process of design of a Generation System interconnection between a Generation System and the Company, there are several studies that many need to be undertaken. On the Local EPS (Customers side of the interconnection), the addition of a Generation System may increase the fault current levels, even if the generation is never interconnected with the Company's system. The Interconnection Customer may need to conduct a fault current analysis of the Local EPS in conjunction with adding the Generation System. The addition of the Generation System may also affect the Company and special engineering studies may need to be undertaken looking at the Company with the Generation System included. Appendix D lists some of the issues that may need to receive further analysis for the Generation System interconnection.

While it is not a straightforward process to identify which engineering studies are required, we can use screening criteria to identify which Generation Systems may require further analysis. The following are the basic screening criteria to be used for this interconnection process:

1) Generation System total Nameplate Capacity does not exceed 5% of the radial circuit expected peak load. The peak load is the total expected load on the radial circuit when the other generators on that same radial circuit are not in operation.

2) The aggregate generation's total Nameplate Capacity, including all existing and proposed generation, does not exceed 25% of the radial circuit peak load and that total is less than the radial circuit's minimum load.

3) Generation System does not exceed 15% of the Annual Peak Load for the Line Section with which it will interconnect. A Line Section is defined as that section of the distribution system between two sectionalizing devices in the Company's distribution system.

4) Generation System does not contribute more than 10% to the distribution circuit's maximum fault current at the point of interconnection with the Company's primary distribution voltage.

5) The proposed Generation System total Nameplate Capacity, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment to exceed 85 percent of the short circuit interrupting capability.

6) If the proposed Generation System is to be interconnected on a single-phase shared secondary, the aggregate generation Nameplate Capacity on the shared secondary, including the proposed generation, does not exceed 20 kW.

7) Generation System will not be interconnected with a "networked" system.

E) Scoping Meeting

During Step 2 of this process, the Applicant or the Company Operator has the option to request a scoping meeting. The purpose of the scoping meeting shall be to discuss the Applicant's interconnection request and review the application filed. This scoping meeting is to be held so that each Party can gain a better understanding of the issues involved with the requested interconnection. The Company and Applicant shall bring to the meeting personnel, including system engineers, and other resources as may be reasonably required, to accomplish the purpose of the meeting. The Applicant shall not expect the Company to complete the preliminary review of the proposed Generation System at the scoping meeting. If a scoping meeting is requested, the Company shall schedule the scoping meeting within the 15 business day review period allowed for in Step 2. The Company shall then have an additional 5 days, after the completion of the scoping meeting to complete the formal response required in Step 2. The Application fee shall cover the Company's costs for this scoping meeting. There shall be no additional charges imposed by the Company for this initial scoping meeting.

F) Insurance

1) At a minimum, in connection with the Interconnection Customer's performance of its duties and obligations under the Interconnection Agreement, the Interconnection Customer shall maintain, during the term of the Agreement, general liability insurance, from a qualified insurance agency with a B+ or better rating by "Best" and with a combined single limit of not less than:

   a) Two million dollars ($2,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is greater then 250 kW.

   b) One million dollars ($1,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is between 20 kW and 250 kW.

   c) Three hundred thousand ($300,000) for each occurrence if the Gross Nameplate Rating of the Generation System is less than 20 kW.

   d) Such general liability insurance shall include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Interconnection Customer's ownership and/or operation of the Generation System under this agreement.

2) The general liability insurance required shall, by endorsement to the policy or policies, (a) include the Company Operator as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that the Company Operator shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to the Company Operator prior to cancellation, termination, alteration, or material change of such insurance.

3) If the Generation System is connected to an account receiving residential service from the Company Operator and it total generating capacity is 20 kW or smaller, then the endorsements required in Section F.2 shall not apply.

4) The Interconnection Customer shall furnish the required insurance certificates and endorsements to the Company Operator prior to the initial operation of the Generation System. Thereafter, the Company Operator shall have the right to periodically inspect or obtain a copy of the original policy or policies of insurance

5) Evidence of the insurance required in Section F.1 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by the Company Operator.

6) If the Interconnection Customer is self-insured with an established record of self-insurance, the Interconnection Customer may comply with the following in lieu of Section F.1 - F.5:

7) Interconnection Customer shall provide to the Company Operator, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under Section F.1 - F.5.

8) If Interconnection Customer ceases to self-insure to the level required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of it's ability to self-insure, the Interconnection Customer agrees to immediately obtain the coverage required under Section F.1 - F.5.

Failure of the Interconnection Customer or Company Operator to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

G) Pre-Certification

The most important part of the process for interconnecting generation with Local and Company's systems is safety. One of the key components of ensuring the safety of the public and employees is to ensure that the design and implementation of the elements connected to the electrical power system operate as required. To meet this goal, all of the electrical wiring in a business or residence, is required to be listed by a recognized testing and certification laboratory for its intended purpose. Typically, we see this as "UL" listed. Since Generation Systems have tended to be uniquely designed for each installation, they have been designed and approved by Professional Engineers. This process has been set up to be able to deal with these uniquely designed systems. As the number of Generation Systems installed increase, vendors are working towards creating equipment packages that can be type-tested in the factory and then will only require limited field-testing. This will allow us to move towards "plug and play" installations. For this reason, this interconnection process recognizes the efficiently of "pre-certification" of Generation System equipment packages that will help streamline the design and installation process.

An equipment package shall be considered certified for interconnected operation if it has been submitted by a manufacture to and tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous utility interactive operation in compliance with the applicable codes and standards. Presently generation paralleling equipment that is listed by a nationally recognized testing laboratory as having met the applicable type-testing requirements of IEEE 1547.1, including UL 1741, shall be acceptable for interconnection. An "equipment package" shall include all interface components including switchgear, inverters, or other interface devices and may include an integrated generator or electric source. If the equipment package has been type-tested and listed as an integrated package which includes a generator or other electric source, it shall not require further design review, testing or additional equipment to meet the certification requirements for interconnection. If the equipment package includes only the interface components (switchgear, inverters, or other interface devices), then the Interconnection Customer shall show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and consistent with the testing and listing specified for the package. Provided the generator or electric source combined with the equipment package is consistent with the testing and listing performed by the nationally recognized testing and certification laboratory, no further design review, testing or additional equipment shall be required to meet the certification requirements of this interconnection procedure. A certified equipment package does not include equipment provided by the Company.

The use of Pre-Certified equipment does not automatically qualify the Interconnection Customer to be interconnected to the Company. 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 Company. Typically, small Generation facilities utilizing pre-certified equipment would not be required to provide additional protective equipment. For larger installations, some additional equipment is often required. These aspects are discussed further in the interconnection requirements document.

H) Confidential Information

Except as otherwise agreed, each Party shall hold in confidence and shall not disclose confidential information to any person (except employees, officers, representatives, and agents who agree to be bound by this section).

Confidential information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency, or entity with the right, power, and authority to do so, requests or requires either Party, by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver, the Party shall disclose such confidential information which, in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded any confidential information so furnished.

I) **Non-Warranty**

Neither by inspection, if any, or non-rejection, nor in any other way, does the Company Operator give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Applicant or leased by the Applicant from third parties, including without limitation the Generation System and any structures, equipment, wires, appliances or devices pertinent thereto.

J) **Required Documents**

The chart below lists the documents required for each type and size of Generation System proposed for interconnection. Find your type of Generation System interconnection, across the top, then follow the chart straight down, to determine what documents are required as part of the interconnection process.

<table>
<tr><th colspan="6">GENERATION INTERCONNECTION DOCUMENT SUMMARY</th></tr>
<tr><th rowspan="2">Open Transfer</th><th rowspan="2">Quick Closed & Quick Open Transfer</th><th rowspan="2">Soft Loading Transfer</th><th colspan="3">Extended Parallel Operation</th></tr>
<tr><th>QF facility <=20 kW</th><th>Without Sales</th><th>With Sales</th></tr>
<tr><td colspan="6">Interconnection Process (This document)</td></tr>
<tr><td></td><td colspan="5">Interconnection Requirements for Extended Paralleled Distribution Generation Systems</td></tr>
<tr><td></td><td colspan="5">Generation Interconnection Application (Appendix B)</td></tr>
<tr><td colspan="2"></td><td colspan="4">Engineering Data Submittal (Appendix C)</td></tr>
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<tr><td colspan="4"></td><td colspan="2">MISO / FERC</td></tr>
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</table>

<u>Interconnection Process</u> = "Interconnection Process for Distributed Generation Systems." (This document)

<u>Generation Interconnection Application</u> = The application form in Appendix B of this document.

<u>Engineering Data Submittal</u> = The Engineering Data Form/Agreement, which is attached as Appendix C of this document.

Interconnection Agreement = "Interconnection Agreement for the Interconnection of Extended Parallel Distributed Generation Systems with the Company", which is attached as Appendix E to this document.

MISO = Midwest Independent System Operator, www.midwestiso.org

FERC = Federal Energy Regulatory Commission, www.ferc.gov

PPA = Power Purchase Agreement.

Process for Interconnection

Step 1 Application (By Applicant)

Once a decision has been made by the Applicant that they would like to interconnect a Generation System with the Company, the Applicant shall supply the Company with the following information:

1) Completed Generation Interconnection Application (Appendix B), including;
   a) One-line diagram showing:
      i) Protective relaying.
      ii) Point of Common Coupling.
   b) Site plan of the proposed installation.
   c) Proposed schedule of the installation.
2) Payment of the application fee, according to the following sliding scale:

Generation Interconnection Application Fees

Interconnection Type	≤ 20 kW	>20 kW & ≤250 kW	>250 kW & ≤500 kW	> 500 kW & ≤1000 kW	>1000 kW
Open Transfer	$0	$0	$0	$100	$100
Quick Closed & Quick Open	$0	$100	$100	$250	$500
Soft Loading	$100	$250	$500	$500	$1000
Extended Parallel (Pre-Certified System)	$0	$250	$1000	$1000	$1500
Other Extended Parallel Systems	$100	$500	$1500	$1500	$1500

This application fee is to contribute to the Company Operator's labor costs for administration, review of the design concept, and preliminary engineering screening for the proposed Generation System interconnection.

For the Application Fees chart above:
The size (kW) of the Generation System is the total maximum Nameplate Capacity of the Generation System.

Step 2 Preliminary Review (By the Company)

Within 15 business days of receipt of all the information listed in Step 1, the Company's Generation Interconnection Coordinator shall respond to the Applicant with the information listed below. (If the information required in Step 1 is not complete, the Applicant will be notified, within 10 business days of what is missing and no further review will be completed until the missing information is submitted. The 15-day clock will restart with the new submittal)

As part of Step 2, the proposed Generation System will be screened to see if additional Engineering Studies are required. The base screening criteria is listed in the general information section of this document.

1) A single point of contact with the Company Operator for this project. (Generation Interconnection Coordinator)

2) Approval or rejection of the generation interconnection request.
   a) Rejection – The Company shall supply the technical reasons, with supporting information, for rejection of the interconnection Application.
   b) Approval - An approved Application is valid for 6 months from the date of the approval. The Company Generation Interconnection Coordinator may extend this time if requested by the Applicant.

3) If additional specialized engineering studies are required for the proposed interconnection, the following information will be provided to the Applicant. Typical Engineering Studies are outlined in Appendix D. The costs to the Applicant, for these studies will not exceed the values shown in the following table for pre-certified equipment.

Generation System Size	Engineering Study Maximum Costs
<20 kW	$0
20 kW – 100 kW	$500
100 kW – 250 kW	$1000
>250 kW or not pre-certified equipment	Actual costs

   a) General scope of the engineering studies required.
   b) Estimated cost of the engineering studies.
   c) Estimated duration of the engineering studies.
   d) Additional information required allowing the completion of the engineering studies.
   e) Study authorization agreement.

4) Comments on the schedule provided.

5) If the rules of MISO (Midwest Independent System Operator) require that this interconnection request be processed through the MISO process, the Generation Interconnection Coordinator will notify the Applicant that the generation system is not eligible for review through the State process.

Step 3 Go-No Go Decision for Engineering Studies (By Applicant)

In this step, the Applicant will decide whether or not to proceed with the required engineering studies for the proposed generation interconnection. If no specialized engineering studies are required by the Company Operator, the Company Operator and the Applicant will automatically skip this step.

If the Applicant decides NOT to proceed with the engineering studies, the Applicant shall notify the Company Generation Interconnection Coordinator so other generation interconnection requests in the queue are not adversely impacted. Should the Applicant decide to proceed, the Applicant shall provide the following to the Company Generation Interconnection Coordinator:

1) Payment required by the Company Operator for the specialized engineering studies.

2) Additional information requested by the Company Operator to allow completion of the engineering studies.

Step 4 Engineering Studies (By Company)

In this step, the Company Operator will be completing the specialized engineering studies for the proposed generation interconnection as outlined in Step 2. These studies should be completed in the time frame provided in Step 2, by the Company. It is expected that the Company Operator shall make all reasonable efforts to complete the Engineering Studies within the time frames shown below. If additional time is required to complete the engineering studies, the Generation Interconnection Coordinator shall notify the Applicant and provide the reasons for the time extension. Upon receipt of written notice to proceed, payment of applicable fee, and receipt of all engineering study information requested by the Company Operator in Step 2, the Company Operator shall initiate the engineering studies.

Generation System Size	Engineering Study Completion
<=20 kW	20 working days
>20 kW – 250 kW	30 working days
>250 kW – 1 MW	40 working days
> 1 MW	90 working days

Once it is known by the Company Operator that the actual costs for the engineering studies will exceed the estimated amount by more the 25%, then the Applicant shall be notified. The Company Operator shall then provide the reason(s) for the studies needing to exceed the original estimated amount and provide an updated estimate of the total cost for the engineering studies. The Applicant shall be given the option of either withdrawing the application, or paying the additional estimated amount to continue with the engineering studies.

Step 5 Study Results and Construction Estimates (By the Company)

Upon completion of the specialized engineering studies, or if none were necessary, the following information will be provided to the Applicant.

1) Results of the engineering studies, if needed.

2) Monitoring & control requirements for the proposed generation.

3) Special protection requirements for the Generation System interconnection.

4) Comments on the schedule proposed by the Applicant.

5) Interconnection Agreement (if applicable).

6) Cost estimate and payment schedule for required Company work, including, but not limited to;
   a) Labor costs related to the final design review.
   b) Labor & expense costs for attending meetings.
   c) Required Dedicated Facilities and other Company modification(s).
   d) Final acceptance testing costs.

Step 6 Final Go-No Go Decision (By Applicant)

In this step, the Applicant shall again have the opportunity to indicate whether they want to proceed with the proposed generation interconnection. If the decision is NOT to proceed, the Applicant will notify the Company Generation Interconnection Coordinator so that other generation interconnections in the queue are not adversely impacted. Should the Applicant decide to proceed, a more detailed design, if not already completed by the Company, must be done, and the following information is to be supplied to the Company Generation Interconnection Coordinator:

1) Applicable up-front payment required by the Company, per Payment Schedule provided in Step 5 (if applicable).

2) Signed Interconnection Agreement (if applicable).

3) Final proposed schedule incorporating the Company comments. The schedule of the project should include such milestones as foundations poured, equipment delivery dates, all conduit installed, cutover (energizing of the new switchgear/transfer switch), Company work, relays set and tested, preliminary vendor testing, final Company acceptance testing, and any other major milestones.

4) Detailed one-line diagram of the Generation System, including the generator, transfer switch/switchgear, service entrance, lockable and visible disconnect, metering, protection and metering CT's / VT's, protective relaying, and generator control system.

5) Detailed information on the proposed equipment including wiring diagrams, models, and types.

6) Proposed relay settings for all interconnection required relays.

7) Detailed site plan of the Generation System.

8) Drawing(s) showing the monitoring system (as required per table 5A and section 5 of the "Interconnection Requirements for Extended Paralleled Distribution Generation Systems"; including a drawing that shows the interface terminal block with the Company monitoring system.

9) Proposed testing schedule and initial procedure, including;
   a) Time of day (after-hours testing required?).
   b) Days required.
   c) Testing steps proposed.

Step 7 Final Design Review (By the Company)

Within 15 business days of receipt of the information required in Step 6, the Company Generation Interconnection Coordinator will provide the Applicant with an estimated time table for final review. If the information required in Step 6 is not complete, the Applicant will be notified, within 10 business days of what information is missing. No further review may be completed until the missing information is submitted. The 15-business day clock will restart with the new submittal. This final design review shall not take longer then 15 additional business days to complete, for a total of 30 business days.

During this step, the Company shall complete the review of the final Generation System design. If the final design has significant changes from the Generation System proposed on the original Application, which invalidate the engineering studies or the preliminary engineering screening, the Generation System Interconnection Application request may be rejected by the Company Operator and the Applicant may be requested to reapply with the revised design.

Upon completion of this step, the Generation Interconnection Coordinator shall supply the following information to the Applicant.

1) Requested modifications or corrections of the detailed drawings provided by the Applicant.

2) Approval of and agreement with the Project Schedule. (This may need to be interactively discussed between the Parties during this Step)

3) Initial testing procedure review comments. (Additional work on the testing process will occur during Step 8, once the actual equipment is identified)

Step 8 Order Equipment and Construction (By Both Parties)

The following activities shall be completed during this step. For larger installations, this step will involve much interaction between the Parties. It is typical for approval drawings to be supplied by the Applicant to the Company for review and comments. It is also typical for the Company to require review and approval of the drawings that cover the interconnection equipment and interconnection protection system. If the Company also requires remote control and/or monitoring, those drawings are also exchanged for review and comment.

By the Applicant's personnel:
1) Ordering of Generation System equipment.
2) Installing Generation System.
3) Submit approval drawings for interconnection equipment and protection systems, as required by the Company Operator.
4) Provide final relay settings to the Company Operator.
5) Submit Completed and signed Engineering Data Submittal form.

6) Submit proof of insurance as required by the Company tariff(s) or interconnection agreements.
7) Submit required electrical inspection forms to the Company Operator.
8) Inspecting and functional testing Generation System components.
9) Work with the Company personnel and equipment vendor(s) to finalize the installation testing procedure.

By the Company personnel:

1) Ordering any necessary Company equipment.
2) Installing and testing any required equipment.
   a) Monitoring facilities.
   b) Dedicated Equipment.
3) Assisting Applicant's personnel with interconnection installation coordination issues.
4) Providing review and input for testing procedures.

Step 9 Final Tests (By Company / Applicant)

Due to equipment lead times and construction, a significant amount of time may take place between the execution of Step 8 and Step 9. During this time, the final test steps are developed and the construction of the facilities is completed. For installations 20 kW and under using pre-certified interconnection equipment, this step is typically highly abbreviated.

Final acceptance testing will commence when all equipment has been installed, all contractor preliminary testing has been accomplished, and all Company preliminary testing of the monitoring and dedicated equipment is completed. One to three weeks prior to the start of the acceptance testing of the generation interconnection, the Applicant shall provide a report stating:

- Generation System meets all interconnection requirements;
- contractor preliminary testing has been completed;
- protective systems are functionally tested and ready;
- and provides a proposed date that the Generation System will be is ready to be energized and acceptance tested.

For non-type certified systems a Professional Electrical Engineer registered in the State is required to provide this formal report.

For smaller systems, scheduling of this testing may be more flexible as less testing time is required than for larger systems.

In many cases, this testing is done after hours to ensure no typical business-hour load is disturbed. If acceptance testing occurs after hours, the Company Operator's labor will be billed at overtime wages. During this testing, the Company Operator will typically require three different tests. These tests can differ depending on which type of communication/monitoring system(s) the Company Operator decides to install at the site.

For problems created by the Company or any Company equipment problems that arise during testing, the Company will fix the problem as soon as reasonably possible. If problems arise during testing which are caused by the Applicant or Applicant's vendor or any vendor supplied or installed equipment, the Company will leave the project until the problem is resolved. Having the testing resume will then be subject to Company personnel's time and availability.

Step 10 (By Company)

After all of the Company Operator's required acceptance testing has been accomplished and all requirements are met, the Company Operator shall provide written approval for normal operation of the Generation System interconnection within 3 business days of the successful completion of the acceptance tests.

Step 11 (By Applicant)

Within two (2) months of interconnection, the Applicant shall provide the Company with updated drawings and prints showing the Generation System as approved for normal operation by the Company Operator. The drawings shall include all changes that were made during the construction and the testing process.

Attachments:

Attached are several documents that may be required for the interconnection process. They are as follows:

Appendix A: Flow chart showing summary of the interconnection process.

Appendix B: Generation Interconnection Application Form.

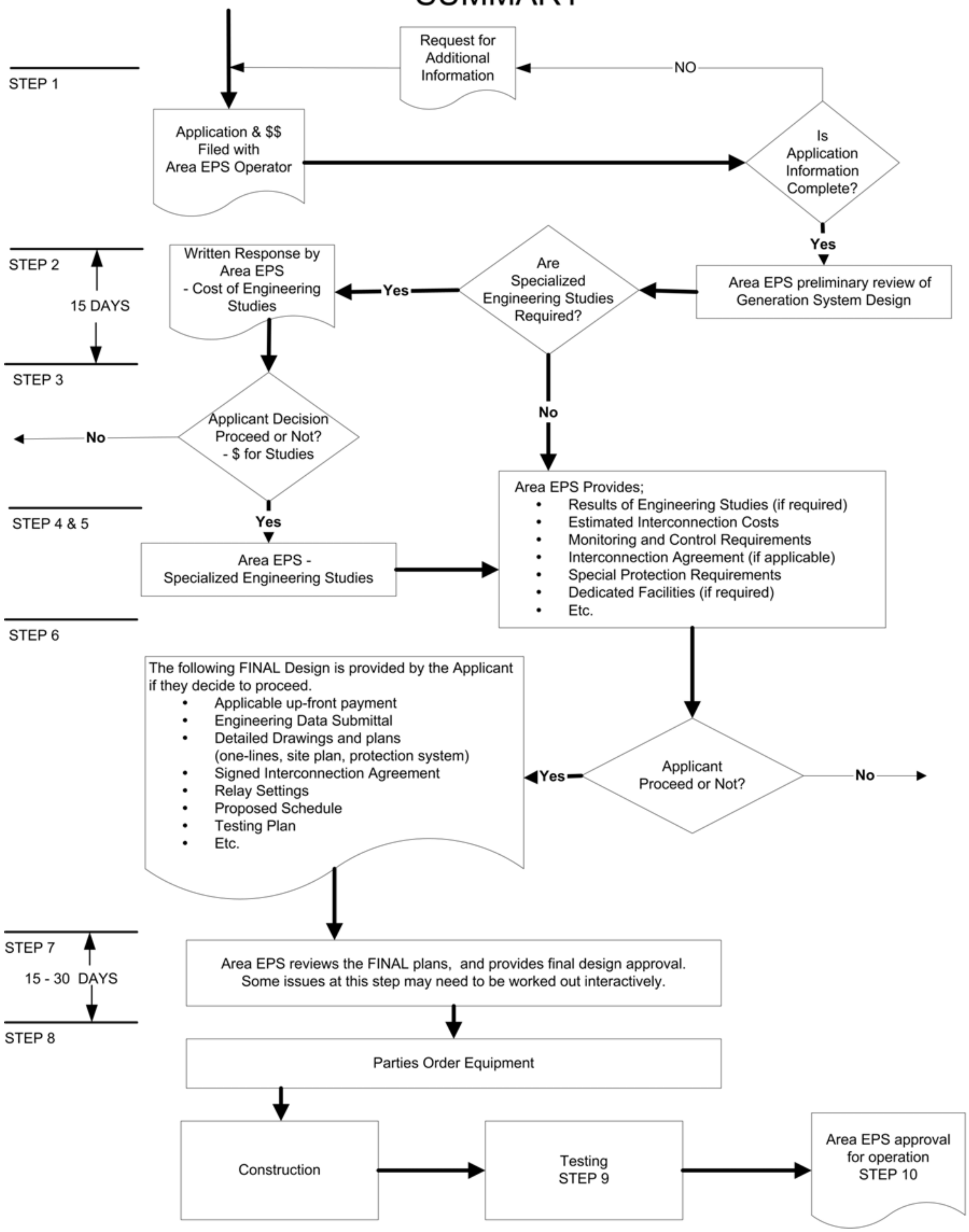
Appendix C: Engineering Data Submittal Form.

Appendix D: Engineering Studies: Brief description of the types of possible Engineering Studies that may be required for the review of the Generation System interconnection.

Appendix E: Interconnection Agreement for the Interconnection of Extended Paralleled Distributed Generation Systems with the Company.

.APPENDIX A

DISTRIBUTED GENERATION INTERCONNECTION PROCESS SUMMARY



APPENDIX B

Application to Interconnect Form

WHO SHOULD FILE THIS APPLICATION: Anyone expressing interest to install generation that will interconnect with the Company. This application should be completed and returned to the Company Generation Interconnection Coordinator in order to begin processing the request.
INFORMATION: This application is used by the Company Operator to perform a preliminary interconnection review. The Applicant shall complete as much of the form as possible. The fields in BOLD are required to be completed to the best of the Applicant's ability. The Applicant will be contacted if additional information is required. The response may take up to 15 business days after receipt of all the required information.
COST: A payment to cover the application fee shall be included with this application. The application fee amount is outlined in the "Interconnection Process for Distributed Generation Systems".

OWNER/APPLICANT		
Company / Applicant's Name:		
Representative:	**Phone Number:**	**FAX Number:**
Title:		
Mailing Address:		
Email Address:		
LOCATION OF GENERATION SYSTEM INTERCONNECTION		
Street Address, legal description or GPS coordinates:		
PROJECT DESIGN / ENGINEERING (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		
ELECTRICAL CONTRACTOR (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		
GENERATOR		
Manufacturer:		Model:
Type (Synchronous Induction, Inverter, etc):		**Phases: 1 or 3**
Rated Output (Prime kW):	**(Standby kW):**	**Frequency:**
Rated Power Factor (%):	**Rated Voltage (Volts):**	Rated Current (Amperes):
Energy Source (gas, steam, hydro, wind, etc.)		
TYPE OF INTERCONNECTED OPERATION		
Interconnection / Transfer method: □ **Open** □ **Quick Open** □ **Closed** □ **Soft Loading** □ **Inverter**		
Proposed use of generation: (Check all that may apply) □ **Peak Reduction** □ **Standby** □ **Energy Sales** □ **Cover Load**	**Duration Parallel:** □ **None** □ **Limited** □ **Continuous**	

Pre-Certified System: Yes / No (Circle one)	**Exporting Energy Yes / No (Circle one)**

ESTIMATED LOAD INFORMATION

The following information will be used to help properly design the interconnection. This Information is not intended as a commitment or contract for billing purposes.

Minimum anticipated load (generation not operating):	**kW:**	**kVA:**
Maximum anticipated load (generation not operating):	**kW:**	**kVA:**

ESTIMATED START/COMPLETION DATES

Construction start date:	**Completion (operational) date:**

DESCRIPTION OF PROPOSED INSTALLATION AND OPERATION

Attach a single line diagram showing the switchgear, transformers, and generation facilities. Give a general description of the manner of operation of the generation (cogeneration, closed-transition peak shaving, open-transition peak shaving, emergency power, etc.). Also, does the Applicant intend to sell power and energy or ancillary services and/or wheel power over Company facilities? If there is intent to sell power and energy, also define the target market?

SIGN-OFF AREA:

With this Application, we are requesting the Company Operator to review the proposed Generation System Interconnection. We request that the Company identifies the additional equipment and costs involved with the interconnection of this system and to provide a budgetary estimate of those costs. We understand that the estimated costs supplied by the Company Operator will be estimated using the information provided. We also agree that we will supply, as requested, additional information to allow the Company Operator to better review this proposed Generation System interconnection. We have read the “Interconnection Requirements for Extended Paralleled Distribution Generation Systems” and will design the Generation System and interconnection to meet those requirements.

Applicant Name (print):

Applicant Signature: **Date:**

SEND THIS COMPLETED & SIGNED APPLICATION AND ATTACHMENTS TO THE COMPANY GENERATION INTERCONNECTION COORDINATOR

APPENDIX C

Engineering Data Submittal Form

WHO SHOULD FILE THIS SUBMITTAL: Anyone in the final stages of interconnecting a Generation System with the Company. This submittal shall be completed and provided to the Company Generation Interconnection Coordinator during the design of the Generation System as established in the "Interconnection Process for Distributed Generation Systems".

INFORMATION: This submittal is used to document the interconnected Generation System. The Applicant shall complete as much of the form as applicable. The Applicant will be contacted if additional information is required.

OWNER / APPLICANT		
Company / Applicant:		
Representative:	Phone Number:	FAX Number:
Title:		
Mailing Address:		
Email Address:		

PROPOSED LOCATION OF GENERATION SYSTEM INTERCONNECTION
Street Address, Legal Description or GPS coordinates:

PROJECT DESIGN / ENGINEERING (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		

ELECTRICAL CONTRACTOR (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		

TYPE OF INTERCONNECTED OPERATION	
Interconnection / Transfer method: □ Open □ Quick Open □ Closed □ Soft Loading □ Inverter	
Proposed use of generation: (Check all that may apply) □ Peak Reduction □ Standby □ Energy Sales □ Cover Load	Duration Parallel: □ None □ Limited □ Continuous
Pre-Certified System: Yes / No (Circle one)	Exporting Energy Yes / No (Circle one)

GENERATION SYSTEM OPERATION / MAINTENANCE CONTACT INFORMATION		
Maintenance Provider:	Phone #:	Pager #:
Operator Name:	Phone #:	Pager #:
Person to Contact before remote starting of units		
Contact Name:	Phone #:	Pager #:
	24 hr Phone #:	

GENERATION SYSTEM OPERATING INFORMATION	
Fuel Capacity (gals):	Full Fuel Run-time (hrs):
Engine Cool Down Duration (Minutes):	Start time Delay on Load Shed signal:
Start Time Delay on Outage (Seconds):	

ESTIMATED LOAD		
The following information will be used to help properly design the interconnection. This Information is not intended as a commitment or contract for billing purposes.		
Minimum anticipated load (generation not operating):	kW:	kVA:
Maximum anticipated load (generation not operating):	kW:	kVA:

REQUESTED CONSTRUCTION START/COMPLETION DATES	
Design Completion:	
Construction Start Date:	
Footings in place:	
Primary Wiring Completion:	
Control Wiring Completion:	
Start Acceptance Testing:	
Generation operational (In-service):	

(Complete all applicable items, copy these pages as required for additional generators)

SYNCHRONOUS GENERATOR (if applicable)			
Unit Number:	Total number of units with listed specifications on site:		
Manufacturer:	Type:	Phases: 1 or 3	
Serial Number (each)	Date of manufacture:	Speed (RPM):	Freq. (Hz);
Rated Output (each unit) kW Standby:	kW Prime:	kVA:	
Rated Power Factor (%):	Rated Voltage (Volts):	Rated Current (Amperes):	
Field Voltage (Volts):	Field Current (Amperes):	Motoring Power (kW):	
Synchronous Reactance (X_d):	% on	kVA base	
Transient Reactance (X'_d):	% on	kVA base	
Subtransient Reactance (X''_d):	% on	kVA base	
Negative Sequence Reactance (X_s):	% on	kVA base	
Zero Sequence Reactance (X_o):	% on	kVA base	
Neutral Grounding Resistor (if applicable):			
I^2t or K (heating time constant):			
Exciter data:			
Governor data: Additional Information:			

INDUCTION GENERATOR (if applicable)			
Rotor Resistance (R_r):	Ohms	Stator Resistance (R_s):	Ohms
Rotor Reactance (X_r):	Ohms	Stator Reactance (X_s):	Ohms
Magnetizing Reactance (X_m):	Ohms	Short Circuit Reactance (X_d''):	Ohms
Design Letter:		Frame Size:	
Exciting Current:		Temp Rise (deg C°):	
Rated Output (kW):			
Reactive Power Required:	kVArs (no Load)	kVArs (full load)	
If this is a wound-rotor machine, describe any external equipment to be connected (resistor, rheostat, power converter, etc.) to rotor circuit, and circuit configuration. Describe ability, if any, to adjust generator reactive output to provide power system voltage regulation.			
Additional Information:			

PRIME MOVER (Complete all applicable items)	
Unit Number:	Type:
Manufacturer:	
Serial Number:	Date of Manufacture:

H.P. Rated:	H.P. Max:	Inertia Constant:	lb.-ft.^{2}
Energy Source (hydro, steam, wind, wind etc.):			

INTERCONNECTION (STEP-UP) TRANSFORMER (If applicable)		
Manufacturer:	kVA:	
Date of Manufacture:	Serial Number:	
High Voltage: kV	Connection: delta wye	Neutral solidly grounded?
Low Voltage: kV	Connection: delta wye	Neutral solidly grounded?
Transformer Impedance (Z):	% on	kVA base
Transformer Resistance (R):	% on	kVA base
Transformer Reactance (X):	% on	kVA base
Neutral Grounding Resistor (if applicable)		

TRANSFER SWITCH (If applicable)	
Model Number:	Type:
Manufacturer:	Rating(amps):

INVERTER (If applicable)		
Manufacturer:	Model:	
Rated Power Factor (%):	Rated Voltage (Volts):	Rated Current (Amperes):
Inverter Type (ferroresonant, step, pulse-width modulation, etc.):		
Type of Commutation: forced line	Minimum Short Circuit Ratio required:	
Minimum voltage for successful commutation:		
Current Harmonic Distortion	Maximum Individual Harmonic (%): Maximum Total Harmonic Distortion (%):	
Voltage Harmonic Distortion	Maximum Individual Harmonic (%): Maximum Total Harmonic Distortion (%):	
Describe capability, if any, to adjust reactive output to provide voltage regulation:		
NOTE: Attach all available calculations, test reports, and oscillographic prints showing inverter output voltage and current waveforms.		

POWER CIRCUIT BREAKER (if applicable)	
Manufacturer:	Model:
Rated Voltage (kilovolts):	Rated Ampacity (Amperes):
Interrupting Rating (Amperes):	BIL Rating:
Interrupting Medium (vacuum, oil, gas, etc.)	Insulating Medium (vacuum, oil, gas, etc.)
Control Voltage (Closing): (Volts) AC DC	
Control Voltage (Tripping): (Volts) AC DC Battery Charged Capacitor	
Close Energy (circle one): Spring Motor Hydraulic Pneumatic Other	
Trip Energy (circle one): Spring Motor Hydraulic Pneumatic Other	
Bushing Current Transformers (Max. ratio):	Relay Accuracy Class:
CT'S Multi Ratio? (circle one); No / Yes: (Available taps):	

MISCELLANEOUS (Use this area and any additional sheets for applicable notes and comments)

SIGN OFF AREA

This Engineering Data Submittal documents the equipment and design of the Generation System. We agree to supply the Company Operator with an updated Engineering Data Submittal any time significant changes are made in the equipment used or the design of the proposed Generation System. The Applicant agrees to design, operate, and maintain the Generation System within the requirements set forth by the "Interconnection Requirements for Extended Paralleled Distribution Generation Systems".

Applicant Name (print):	
Applicant Signature:	**Date:**

SEND THIS COMPLETED & SIGNED ENGINEERING DATA SUBMITTAL AND ANY ATTACHMENTS TO THE COMPANY GENERATION INTERCONNECTION COORDINATOR

APPENDIX D

Engineering Studies

For the engineering studies, there are two main parts of the study: 1. Does the distributed generator cause a problem? and 2. What would it cost to make a change to handle the problem? The first question is relatively straightforward to determine as the Company Engineer reviews the proposed installation. The second question typically has multiple alternatives and can turn into an iterative process. This iterative process can become quite large for more complex generation installations. For the Engineer, there is no "cook book" solution that can be applied.

For some of the large generation installations and/or the more complex interconnections, the Company Operator may suggest dividing the engineering studies into the two parts: 1. identify the scope of the problems, and 2. attempt to identify solutions to resolve the problems. By splitting the engineering studies into two steps, it will allow the Applicant to see the problems identified and to provide the Applicant the ability to remove the request for interconnection if the problems are too large and expensive to resolve. This would then save the additional costs to the Applicant for the more expensive engineering studies to identity ways to resolve the problem(s).

This appendix provides an overview of some of the main issues that are looked at during the engineering study process. Every interconnection has its unique issues, such as relative strength of the distribution system, ratio of the generation size to the existing area loads, etc. Thus, many of the generation interconnections will require further review of one or several of the issues listed.

- Short circuit analysis – the system is studied to make sure that the addition of the generation will not over stress any of the Company equipment and that equipment will still be able to clear during a fault. It is expected that the Applicant will complete their own short circuit analysis on their equipment to ensure that the addition of the generation system does not overstress the Applicant's electrical equipment.

- Power Flow and Voltage Drop
    - Reviews potential islanding of the generation.
    - Will Company Equipment be overloaded?
        - Under normal operation?
        - Under contingent operation?
        - With backfeeds?

- Flicker Analysis –
    - Will the operation of the generation cause voltage swings?
        - When it loads up?
        - When it off-loads?
    - How will the generation interact with Company voltage regulation?
    - Will Company capacitor switching affect the generation while on-line?

- Protection Coordination
    - Reclosing issues – this is where the reclosing for the distribution system and transmission system are looked at to see if the Generation System protection can be set up to ensure that it will clear from the distribution system before the feeder is reenergized.
        - Is voltage supervision of reclosing needed?
    - Is transfer-trip required?
    - Do we need to modify the existing protection systems? Existing settings?
    - At which points do we need "out of sync" protection?
    - Is the proposed interconnection protection system sufficient to sense a problem on the Company's system?
    - Are there protection problems created by the step-up transformer?

- Grounding Reviews
    - Does the proposed grounding system for the Generation System meet the requirements of the NESC? "National Electrical Safety Code" published by the Institute of Electrical and Electronics Engineers (IEEE)

- System Operation Impact.
    - Are special operating procedures needed with the addition of the generation?

- Reclosing and out of sync operation of facilities?
- What limitations need to be placed on the operation of the generation?
- Operational var requirements?

APPENDIX E

Interconnection Agreement for the Interconnection of Extended Parallel Distributed Generation Systems

This Generating System Interconnection Agreement is entered into by and between the Area Electrical Power System Operator (Company Operator) "________________________" and the Interconnection Customer "_____________________________". The Interconnection Customer and the Company are sometimes also referred to in this Agreement jointly as "Parties" or individually as "Party".

In consideration of the mutual promises and obligations stated in this Agreement and its attachments, the Parties agree as follows:

I. SCOPE AND PURPOSE

A) Establishment of Point of Common Coupling: This Agreement is intended to provide for the Interconnection Customer to interconnect and operate a Generation System, with a total Nameplate Capacity of 10 MWs or less, in parallel with the Company at the location identified in Exhibit C and shown in the Exhibit A one-line diagram.

B) This Agreement governs the facilities required to and contains the terms and condition under which the Interconnection Customer may interconnect the Generation System to the Company. This Agreement does not authorize the Interconnection Customer to export power or constitute an agreement to purchased or wheel the Interconnection Customer's power. Other services that the Interconnection Customer may require from the Company, or others, may be covered under separate agreements.

C) To facilitate the operation of the Generation System, this agreement also allows for the occasional and inadvertent export of energy to the Company. The amount, metering, billing, and accounting of such inadvertent energy exporting shall be governed by Exhibit D (Operating Agreement). This Agreement does not constitute an agreement by the Company Operator to purchase or pay for any energy, inadvertently or intentionally exported, unless expressly noted in Exhibit D or under a separately executed power purchase agreement (PPA).

D) This agreement does not constitute a request for, nor the provision of, any transmission delivery service or any local distribution delivery service.

E) The Technical Requirements for interconnection are covered in a separate Technical Requirements document known as the "Interconnection Requirements for Extended Paralleled Distribution Generation Systems", a copy of which as been made available to the Interconnection Customer and incorporated and made part of this Agreement by this reference.

II. DEFINITIONS

A) "Area EPS" - the area electric power system that is also referred to as the Company electric distribution system in this document.

B) "Company" - an electric power system (EPS) that serves the Local EPS. Note: Typically, the Company has primary access to public rights-of-way, priority crossing of property boundaries, etc.

C) "Company Operator" - the entity that operates the Company's electric distribution system.

D) "Commission" – The public utilities commission of the State wherein the Generation Facility is located.

E) "Dedicated Facilities" - the equipment that is installed due to the interconnection of the Generation System and not required to serve other Company customers.

F) "EPS" - (Electric Power System) facilities that deliver electric power to a load. Note: This may include generation units.

G) "Extended Parallel" - means the Generation System is designed to remain connected with the Company for an extended period of time.

H) "Generation" - 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.

I) "Generation Interconnection Coordinator" - the person or persons designated by the Company Operator to provide a single point of coordination with the Applicant for the generation interconnection process.

J) "Generation System" - the interconnected generator(s), controls, relays, switches, breakers, transformers, inverters and associated wiring and cables up to the Point of Common Coupling.

K) "Interconnection Customer" - the party or parties who will own/operate the Generation System and are responsible for meeting the requirements of the agreements and Technical Requirements. This could be the Generation System applicant, installer, owner, designer, or operator.

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

M) "Nameplate Capacity" - the total nameplate capacity rating of all the Generation included in the Generation System. For this definition, the "standby" and/or maximum rated kW capacity on the nameplate shall be used.

N) "Open Transfer" - a method of transferring the local loads from the Company to the generator such that the generator and the Company are never connected together.

O) "Point of Common Coupling" - the point where the Local EPS is connected to the Company's distribution system.

P) "Point of Delivery" - the point where the energy changes possession from one party to the other. Typically this will be where the metering is installed but it is not required that the Point of Delivery is the same as where the energy is metered.

Q) "Quick Closed" - a method of generation transfer that parallels for less than 100 msec with the Company and has utility grade timers that limit the parallel duration to less than 100 msec with the Company.

R) "Quick Open" - a method of generation transfer that does not parallel with the Company and has a brief open interval, typically about 100 msec.

S) "Soft Loading Transfer": - a method of generation load transfer that parallels for typically less than 2 minutes to gradually transfer load between the generator and the Company.

T) "State" - the state wherein the interconnected generator is located.

U) "Technical Requirements" - "Requirements for Interconnection of Distributed Generation".

III. DESCRIPTION OF INTERCONNECTION CUSTOMER'S GENERATION SYSTEM

A) A description of the Generation System, including a single-line diagram showing the general arrangement of how the Interconnection Customer's Generation System is interconnected with the Company's distribution system, is attached to and made part of this Agreement as Exhibit A. The single-line diagram shows the following:

1) Point of Delivery (if applicable)

2) Point of Common Coupling

3) Location of Meter(s)

4) Ownership of the equipment.

5) Generation System total Nameplate Capacity ________ kW

6) Scheduled operational (on-line) date for the Generation System.

IV. RESPONSIBILITIES OF THE PARTIES

A) The Parties shall perform all obligations of this Agreement in accordance with all applicable laws and regulations, operating requirements, and good utility practices.

B) Interconnection Customer shall construct, operate, and maintain the Generation System in accordance with the applicable manufacture's recommend maintenance schedule, the Technical Requirements, and in accordance with this Agreement.

C) The Company Operator shall carry out the construction of the Dedicated Facilities in a good and workmanlike manner and in accordance with standard design and engineering practices.

V. CONSTRUCTION

The Parties agree to cause their facilities or systems to be constructed in accordance with the laws of the State and to meet or exceed applicable codes and standards provided by the NESC (National Electrical Safety Code), ANSI (American National Standards Institute), IEEE (Institute of Electrical and Electronic Engineers), NEC (National Electrical Code), UL (Underwriter's Laboratory), Technical Requirements, local building codes, and other applicable ordinances in effect at the time of the installation of the Generation System.

A) Charges and Payments

The Interconnection Customer is responsible for the actual costs to interconnect the Generation System with the Company, including, but not limited to, any Dedicated Facilities attributable to the addition of the Generation System, Company labor for installation coordination, installation testing, and engineering review of the Generation System and interconnection design. Estimates of these costs are outlined in Exhibit B. While estimates, for budgeting purposes, have been provided in Exhibit B, the actual costs are still the responsibility of the Interconnection Customer even if they exceed the estimated amount(s). All costs, for which the Interconnection Customer is responsible must be reasonable under the circumstances of the design and construction.

1) Dedicated Facilities

a) During the term of this Agreement, the Company Operator shall design, construct, and install the Dedicated Facilities outlined in Exhibit B. The Interconnection Customer shall be responsible for paying the actual costs of the Dedicated Facilities attributable to the addition of the Generation System.

b) Once installed, the Dedicated Facilities shall be owned and operated by the Company and all costs associated with the operating and maintenance of the Dedicated Facilities, after the Generation System is operational, shall be the responsibility of the Company Operator unless otherwise agreed.

c) By executing this Agreement, the Interconnection Customer grants permission for the Company Operator to begin construction and to procure the necessary facilities and equipment to complete the installation of the Dedicated Facilities as outlined in Exhibit B. If for any reason, the Generation System project is canceled or modified, so that any or all of the Dedicated Facilities are not required, the Interconnection Customer shall be responsible for all costs incurred by the Company, including, but not limited to, the additional costs to remove and/or complete the installation of the Dedicated Facilities. The Interconnection Customer may, for any reason, cancel the Generation System project so that any or all of the Dedicated Facilities are not required to be installed. The Interconnection Customer shall provide written notice to the

Company Operator of cancellation. Upon receipt of a cancellation notice, the Company Operator shall take reasonable steps to minimize additional costs to the Interconnection Customer, where reasonably possible.

2) Payments

a) The Interconnection Customer shall provide reasonable adequate assurances of credit including a letter of credit or personal guaranty of payment and performance from a creditworthy entity acceptable under the Company Operator's credit policy and procedures for the unpaid balance of the estimated amount shown in Exhibit B.

b) The payment for the costs outlined in Exhibit B, shall be as follows;

i. 1/3 of estimated costs, outlined in Exhibit B, shall be due upon execution of this agreement.

ii. 1/3 of estimated costs, outlined in Exhibit B, shall be due before initial energization of the Generation System with the Company.

iii. Remainder of actual costs incurred by the Company shall be due within 30 days from the date the bill is mailed by the Company after project completion.

VI. DOCUMENTS INCLUDED WITH THIS AGREEMENT.

A) This agreement includes the following exhibits, which are specifically incorporated herein and made part of this Agreement by this reference*: (if any of these Exhibits are deemed not applicable for this Generation System installation, they may be omitted from the final Agreement by the Company Operator.)*

1) <u>Exhibit A</u> – Description of Generation System and single-line diagram. This diagram shows all major equipment, including visual isolation equipment, Point of Common Coupling, Point of Delivery for Generation Systems that intentionally export, ownership of equipment, and the location of metering.

2) <u>Exhibit B</u> – Estimated installation and testing costs payable by the Interconnection Customer. Included in this listing shall be the description and estimated costs for the required Dedicated Facilities being installed by the Company Operator for the interconnection of the Generation System and a description and estimate for the final acceptance testing work to be done by the Company Operator.

3) <u>Exhibit C</u> – Engineering Data Submittal – A standard form that provides the engineering and operating information about the Generation System.

4) <u>Exhibit D</u> – Operating Agreement – This provides specific operating information and requirements for this Generation System interconnection. This Exhibit has a separate signature section and may be modified, in writing, from time to time with the agreement of both parties.

5) <u>Exhibit E</u> – Maintenance Agreement – This provides specific maintenance requirements for this Generation System interconnection. This Exhibit has a separate signature section and may be modified, in writing, from time to time with the agreement of both parties.

VII. TERMS AND TERMINATION

A) This Agreement shall become effective as of the date when both the Interconnection Customer and the Company Operator have both signed this Agreement. The Agreement shall continue in full force and effect until the earliest date that one of the following events occurs:

1) The Parties agree in writing to terminate the Agreement; or

2) The Interconnection Customer may terminate this agreement at any time, by written notice to the Company Operator, prior to the completion of the final acceptance testing of the Generation System by the Company Operator. Once the Generation System is operational, then VII.A.3 applies. Upon receipt of a cancellation notice, the Company Operator shall take reasonable steps to minimize additional costs to the Interconnection Customer, where reasonably possible; or

3) Once the Generation System is operational, the Interconnection Customer may terminate this agreement after 30 days written notice to the Company Operator, unless otherwise agreed to within the Exhibit D, Operating Agreement; or

4) The Company Operator may terminate this agreement after 30 days written notice to the Interconnection Customer if:

   a) The Interconnection Customer fails to interconnect and operate the Generation System per the terms of this Agreement; or

   b) The Interconnection Customer fails to take all corrective actions specified in the Company's written notice that the Generation System is out of compliance with the terms of this Agreement, within the time frame set forth in such notice; or

   c) If the Interconnection Customer fails to complete the Company Operator's final acceptance testing of the generation system within 24 months of the date proposed under section III.A.5.

B) Upon termination of this Agreement, the Generation System shall be disconnected from the Company. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing, at the time of the termination.

VIII. OPERATIONAL ISSUES

Each Party will, at its own cost and expense, operate, maintain, repair, and inspect and shall be fully responsible for the facilities that it now or hereafter may own, unless otherwise specified.

A) Technical Standards: The Generation System shall be installed and operated by the Interconnection Customer consistent with the requirements of this Agreement; the Technical Requirements; the applicable requirements located in the National Electrical Code (NEC); the applicable standards published by the American National Standards Institute (ANSI) and the Institute of Electrical and Electronic Engineers (IEEE); and local building and other applicable ordinances in effect at the time of the installation of the Generation System.

B) Right of Access: At all times, the Company Operator's personnel shall have access to the disconnect switch of the Generation System for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement to meet its obligation to operate the Company safely and to provide service to its customers. If necessary for the purposes of this Agreement, the Interconnection Customer shall allow the Company Operator access to the Company's equipment and facilities located on the premises.

C) Electric Service Supplied: The Company will supply the electrical requirements of the Local EPS that are not supplied by the Generation System. Such electric service shall be supplied to the Interconnection Customer's Local EPS under the rate schedules applicable to the Customer's class of service as revised from time to time by the Company.

D) Operation and Maintenance: The Generation System shall be operated and maintained by the Interconnection Customer in accordance with the Technical Standards and any additional requirements of Exhibit D and Exhibit E, attached to this document, as amended in writing from time to time.

E) Cooperation and Coordination: Both the Company Operator and the Interconnection Customer shall communicate and coordinate their operations so that the normal operation of the Company does not unduly effect or interfere with the normal operation of the Generation System and the Generation System does not unduly effect or interfere with the normal operation of the Company. Under abnormal operations of either the Generation System or the Company system, the responsible Party shall provide reasonably timely communication to the other Party to allow mitigation of any potentially negative effects of the abnormal operation of their system.

F) Disconnection of Unit: The Company Operator may disconnect the Generation System, as necessary, for termination of this Agreement; non-compliance with this Agreement; system emergency, imminent danger to the public or Company personnel; or routine maintenance, repairs and modifications to the Company. When reasonably possible, the Company Operator shall provide prior notice to the Interconnection Customer explaining the reason for the disconnection. If prior notice is not reasonably possible, the Company Operator shall, after the fact, provide information to the Interconnection Customer as to why the disconnection was required. It is agreed that the Company Operator shall have no liability for any loss of sales or other damages, including all consequential damages for the loss of business opportunity, profits, or other losses, regardless of whether such damages were foreseeable, for the disconnection of the Generation System per this Agreement. The Company Operator shall expend reasonable effort to reconnect the Generation System in a timely manner and to work towards mitigating damages and losses to the Interconnection Customer where reasonably possible.

G) Modifications to the Generation System – When reasonably possible, the Interconnection Customer shall notify the Company Operator, in writing, of plans for any modifications to the Generation System interconnection equipment, including all information needed by the Company Operator as part of the review described in this paragraph, at least twenty (20) business days prior to undertaking such modification(s). Modifications to any of the interconnection equipment, including all interconnection required protective systems, the generation control systems, the transfer switches/breakers, interconnection protection VT's & CT's, and Generation System capacity, shall be included in the notification to the Company Operator. When reasonably possible, the Interconnection Customer agrees not to commence installation of any modifications to the Generating System until the Company Operator has approved the modification, in writing, which approval shall not be unreasonably withheld. The Company Operator shall have a minimum of five (5) business days to review and respond to the planned modification. The Company Operator shall not take longer than a maximum of ten (10) business days to review and respond to the modification after the receipt of the information required to review the modifications. When it is not reasonably possible for the Interconnection Customer to provide prior written notice, the Interconnection Customer shall provide written notice to the Company Operator as soon as reasonably possible after the completion of the modification(s).

H) Permits and Approvals: The Interconnection Customer shall obtain all environmental and other permits lawfully required by governmental authorities before the construction of the Generation System. The Interconnection Customer shall also maintain these applicable permits and compliance with these permits during the term of this Agreement.

IX. LIMITATION OF LIABILITY

A) Each Party shall at all times indemnify, defend, and save the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury or death of any person or damage to property, costs and expenses, reasonable attorneys' fees and court costs, arising out of or resulting from the Party's performance of its obligations under this agreement, except to the extent that such damages, losses, or claims were caused by the negligence or intentional acts of the other Party.

B) Each Party's liability to the other Party for failure to perform its obligations under this Agreement shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any punitive, incidental, indirect, special, or consequential damages of any kind whatsoever, including for loss of business opportunity or profits, regardless of whether such damages were foreseen.

C) Notwithstanding any other provision in this Agreement, with respect to Company Operator's provision of electric service to any customer, including the Interconnection Customer, the Company Operator's liability to such customer shall be limited as set forth in the Company Operator's tariffs and terms and conditions for electric service, and shall not be affected by the terms of this Agreement.

X. DISPUTE RESOLUTION

A) Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably, and in a good faith manner.

B) In the event a dispute arises under this Agreement, and if it cannot be resolved by the Parties within thirty (30) days after written notice of the dispute to the other Party, the Parties agree to submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in the State. The Parties agree to participate in good faith in the mediation for a period of 90 days. If the parties are not successful in resolving their disputes through mediation, then the Parties may refer the dispute for resolution to the Commission, which shall maintain continuing jurisdiction over this Agreement.

XI. INSURANCE

A) At a minimum, in connection with the Interconnection Customer's performance of its duties and obligations under this Agreement, the Interconnection Customer shall maintain during the term of the Agreement, general liability insurance from a qualified insurance agency with a B+ or better rating by "Best" and with a combined single limit of not less than:

1) Two million dollars ($2,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is greater then 250 kW.

2) One million dollars ($1,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is between 20 kW and 250 kW.

3) Three hundred thousand ($300,000) for each occurrence if the Gross Nameplate Rating of the Generation System is less than 20 kW.

4) Such general liability insurance shall include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Interconnection Customer's ownership and/or operating of the Generation System under this agreement.

B) The general liability insurance required shall, by endorsement to the policy or policies, (a) include the Company Operator as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that the Company Operator shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to the Company Operator prior to cancellation, termination, alteration, or material change of such insurance.

C) If the Generation System is connected to an account receiving residential service from the Company Operator and its total generating capacity is 20 kW or smaller, then the endorsements required in Section XI.B shall not apply.

D) The Interconnection Customer shall furnish the required insurance certificates and endorsements to the Company Operator before the initial operation of the Generation System. Thereafter, the Company Operator shall have the right to periodically inspect or obtain a copy of the original policy or policies of insurance.

E) Evidence of the insurance required in Section XI.A. shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by the Company Operator.

F) If the Interconnection Customer is self-insured with an established record of self-insurance, the Interconnection Customer may comply with the following in lieu of Section XI.A – E:

1) Interconnection Customer shall provide to the Company Operator, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under section XI.A - E.

2) If Interconnection Customer ceases to self-insure to the level required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of it's ability to self-insure, the Interconnection Customer agrees to immediately obtain the coverage required under Section XI.A - E.

G) Failure of the Interconnection Customer or Company Operator to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

H) All insurance certificates, statements of self-insurance, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

Company___________________

Attention____________________

Address____________________

____

XII. MISCELLANEOUS

A) **FORCE MAJEURE**

1) An event of Force Majeure means any act of God, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. An event of Force Majeure does not include an act of negligence or intentional wrongdoing.

2) Neither Party will be considered in default of any obligation hereunder if such Party is prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations hereunder.

B) **NOTICES**

1) Any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person or sent by first class mail, postage prepaid, to the person specified below:

a) If to Company Operator

Company___________________

Attention____________________

Address____________________

____

b) If to Interconnection Customer

Customer___________________

Address____________________

____

2) A Party may change its address for notices at any time by providing the other Party written notice of the change, in accordance with this Section.

3) The Parties may also designate operating representatives to conduct the daily communications that may be necessary or convenient for the administration of this Agreement. Such designations, including names, addresses, and phone numbers may be communicated or revised by one Party's written notice to the other Party.

C) **ASSIGNMENT**

The Interconnection Customer shall not assign its rights nor delegate its duties under this Agreement without the Company Operator's written consent. Any assignment or delegation the Interconnection Customer makes without the Company Operator's written consent shall not be valid. The Company Operator shall not unreasonably withhold its consent to the Generating Entities assignment of this Agreement.

D) **NON-WAIVER**

None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

E) **GOVERNING LAW AND INCLUSION OF COMPANY OPERATOR'S TARIFFS AND RULES.**

1) This Agreement shall be interpreted, governed, and construed under the laws of the State as if executed and to be performed wholly within the State without giving effect to choice of law provisions that might apply to the law of a different jurisdiction.

2) The interconnection and services provided under this Agreement shall at all times be subject to the terms and conditions set forth in the tariff schedules and rules applicable to the electric service provided by the Company Operator, which tariff schedules and rules are hereby incorporated into this Agreement by this reference.

3) Notwithstanding any other provisions of this Agreement, the Company Operator shall have the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for change in rates, charges, classification, service, tariff, or rule or any agreement relating thereto.

F) **AMENDMENT AND MODIFICATION**

This Agreement can only be amended or modified in writing and signed by both Parties.

G) **ENTIRE AGREEMENT**

This Agreement, including all attachments, exhibits, and appendices, constitutes the entire Agreement between the Parties with regard to the interconnection of the Generation System of the Parties at the Point(s) of Common Coupling expressly provided for in this Agreement and supersedes all prior agreements or understandings, whether verbal or written. It is expressly acknowledged that the Parties may have other agreements covering other services not expressly provided for herein, which agreements are unaffected by this Agreement. Each party also represents that in entering into this Agreement, it has not relied on the promise, inducement, representation, warranty, agreement, or other statement not set forth in this Agreement or in the incorporated attachments, exhibits, and appendices.

H) **CONFIDENTIAL INFORMATION**

Except as otherwise agreed or provided herein, each Party shall hold in confidence and shall not disclose confidential information to any person (except employees, officers, representatives, and agents who agree to be bound by this section). Confidential information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency or entity with the right, power, and authority to do so requests or requires either Party by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver, the Party shall disclose such confidential information that, in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded any confidential information so furnished.

I) **NON-WARRANTY**

Neither by inspection, if any, or non-rejection, nor in any other way, does the Company Operator give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances, or devices owned, installed, or maintained by the Interconnection Customer or leased by the Interconnection Customer from third parties, including without limitation the Generation System and any structures, equipment, wires, appliances, or devices appurtenant thereto.

J) **NO PARTNERSHIP**

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation, or partnership liability upon either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

XIII. SIGNATURES

IN WITNESS WHEREOF, the Parties hereto have caused two originals of this Agreement to be executed by their duly authorized representatives. This Agreement is effective as of the last date set forth below.

Interconnection Customer

By: ________________________________

Name: ______________________________

Title: ______________________________

Date: ______________________________

Company Operator

By: ________________________________

Name: ______________________________

Title: ______________________________

Date: ______________________________

EXHIBIT A

GENERATION SYSTEM DESCRIPTION AND SINGLE-LINE DIAGRAM

(Site specific, TBD)

EXHIBIT B

SUMMARY OF COMPANY COSTS AND DESCRIPTION OF DEDICATED FACILITIES BEING INSTALLED BY THE COMPANY OPERATOR FOR THE INTERCONNECTION OF THE GENERATION SYSTEM

This Exhibit shall provide the estimated total costs that will be the responsibility of the Interconnection Customer. It is assumed that the Initial application has been filed and the engineering studies have been paid for and completed. Therefore, those costs are not included on this listing.

What is listed below is a general outline of some of the major areas where costs could occur. Other costs than those listed below may be included by the Company if those costs are a direct result from the request to interconnect the Generation System. The following list is only a guideline and the Company Operator, for each installation, will be creating a unique Exhibit B that is tailored for that specific Generation System interconnection.

A) Dedicated Facilities (equipment, design, and installation labor)

B) Monitoring & Control System (equipment, design, and installation labor)

C) Design Coordination and Review

D) Construction Coordination Labor Costs

E) Testing (development of tests and physical testing)

F) Contingency

EXHIBIT C

ENGINEERING DATA SUBMITTAL

Attach a completed “Engineering Data Submittal” form from Appendix C of “Interconnection Process for Distributed Generation Systems”.

EXHIBIT D

OPERATING AGREEMENT

Each Generation System interconnection will be unique and will require a unique Operating Agreement. The following is a listing of some of the possible areas that will be covered in an operating agreement. The following has not been developed into a standard agreement due to the unique nature of each Generation System. It is envisioned that this Exhibit will be tailored by the Company Operator for each Generation System interconnection. It is also intended that this Operating Agreement Exhibit will be reviewed and updated periodically to allow the operation of the Generation System to change to meet the needs of both the Company Operator and the Interconnection Customer, if the change does not negatively affect the other Party. There may also be operating changes required by outside issues such has changes in FERC and MISO requirements and/or policies which will require this Operating Agreement to be modified.

The following items are provided to show the general types of items that may be included in this Operating Agreement. The items included in the Operating Agreement shall not be limited to the items shown on this list.

A) Applicable Company Tariffs – Discussion on which tariffs are being applied for this installation and possibly how they will be applied.

B) Var Requirements – How will the Generation System be required to operate to control the power factor of the energy flowing in either direction across the interconnection.

C) Inadvertent Energy – This Operating Agreement needs to provide the method(s) that will be used to monitor, meter, and account for the inadvertent energy used or supplied by the Generation System. Tariffs and operating rules that apply for this Generation System interconnection shall be discussed in this Operating Agreement.

D) Control Issues - Starting and stopping of the generation including the remote starting and stopping, if applicable.

E) Dispatch of Generation Resources - What are the dispatch requirements for the Generation System? Can it only run during Peak Hours? Are there a limited number of hours that it can run? Is it required to have met an availability percentage? This will greatly depend upon the PPA and other requirements. Is the Interconnection Customer required to coordinate outages of the Generation System with the Company?

F) Outages of Distribution System – How are emergency outages handled? How are other outages scheduled? If the Interconnection Customer requires the Company Operator to schedule the outages during after-hours, who pays for the Company Operator's overtime?

G) Notification / Contacts - Who should be notified? How should they be notified? When should they be notified? For what reasons should the notification take place?

   1) Starting of the Generation

   2) Dispatching of Generation

   3) Notification of failures (both Company and Generation System failures)

H) Documentation of Operational Settings – How much fuel will the generation System typically have on hand? How long can it run with this fuel capacity? How is the generation system set to operate for a power failure? These may be issues that should be documented in the Operating Agreement. The following are a couple of examples:

   1) "The Generation System will monitor the Company phase voltage and after 2 seconds of any phase voltage below 90% the generation will be started and the load transferred to the generator if the generation is not already running."

2) "The Generation System will wait for 30 minutes after it senses the return of the Company frequency and voltage before it will automatically reconnect to the Company."

I) Cost of testing for future failures – If a component of the Generation System fails or needs to be replaced, which effects the interconnection with the Company, what is the process for retesting and for replacement? Who pays for the additional costs of the Company to work with the Interconnection Customer to resolve these problems and/or to complete retesting of the modified equipment?

J) Right of Access - At all times, the Company Operator shall have access to the disconnect switch of the Generation System for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement to meet its obligation to operate the Company safely and to provide service to its customers. If necessary for the purposed of this Agreement, the Interconnection Customer shall allow the Company Operator access to the Company's equipment and facilities located on the premises.

Add Signature Section -The Operating Agreement should be set up so that it is individually signed and dated by both parties.

EXHIBIT E

MAINTENANCE AGREEMENT

Each Generation System interconnection will be unique and will require a unique Maintenance Agreement. It is envisioned that this Exhibit will be tailored for each Generation System interconnection. It is also intended that this Maintenance Agreement Exhibit will be reviewed and updated periodically to allow changes to the maintenance of the Generation System to meet the needs of both the Company Operator and the Interconnection Customer, if the change does not negatively affect the other Party. There may also be changes required by outside issues such has changes in FERC and MISO requirements and/or policies that will require this agreement to be modified.

A) Routine Maintenance Requirements

1) Who is providing maintenance – Contact information

2) Periods of maintenance

B) <u>Modifications to the Generation System</u> - The Interconnection Customer shall notify the Company Operator, in writing of plans for any modifications to the Generation System interconnection equipment at least twenty (20) business days before undertaking such modification. Modifications to any of the interconnection equipment including all required protective systems, the generation control systems, the transfer switches/breakers, VT's & CT's, generating capacity, and associated wiring shall be included in the written notification to the Company Operator. The Interconnection Customer agrees not to commence installation of any modifications to the Generating System until the Company Operator has approved the modification, in writing. The Company shall have a minimum of five (5) business days and a maximum of ten (10) business days to review and respond to the modification after the receipt of the information required to review the modifications.

Add signature Section

INTERCONNECTION REQUIREMENTS FOR EXTENDED PARALLELED DISTRIBUTION GENERATION SYSTEMS

TABLE OF CONTENTS

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 the employees working with the Company. 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 system are not compromised. This applies to all electrical systems not just the Company's.

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 that are not covered in other national standards.

This standard covers installation, with an aggregated capacity of 10 MWs or less. Many of the requirements in this document do not apply to small, 20 kW or less generation installations.

1. Introduction

This standard has been developed to document the technical requirements for the interconnection between a Generation System and Company's electric distribution system. This standard covers 3-phase Generation Systems with an aggregate capacity of 10 MWs or less and single-phase Generation Systems with a aggregate capacity of 20 kW or less at the Point of Common Coupling. This standard covers Generation Systems that are interconnected with the Company's distribution facilities. This standard does not cover Generation Systems that are directly interconnected with the Company's Transmission System. Contact the Company 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 areas of the Company's distribution system that have special interconnection needs. One example of a unique area would be one operated as a "networked" system. This standard does not cover the additional special requirements of those systems. The Interconnection Customer must contact the Company Operator to make sure that the Generation System is not proposed for a unique area system. If the planned interconnection is with a unique area, the Interconnection Customer must obtain the additional requirements for interconnecting.

The Company 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 Company.

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 "Interconnection Process for Distributed Generation Systems" for the description of the procedure to follow and the forms to submit. It is important to also get copies of the Company's tariffs concerning generation interconnection which will include rates, costs, and standard conditions. The earlier the Interconnection Customer gets the Company Operator involved in the planning and design of the Generation System interconnection, the smoother the process will go.

A) Definitions

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

i) "Area EPS" – the area electric power system that is also referred to as the Company electric distribution system in this document.

ii) "Company" - an electric power system (EPS) that serves the Local EPS. Note: Typically, the Company has primary access to public rights-of-way, priority crossing of property boundaries, etc.

iii) "Generation" - 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.

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

v) "Interconnection Customer" - 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.

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

vii) "Open Transfer" - a method of transferring the local loads from the Company to the generator such that the generator and the Company are never connected together.

viii) "Point of Common Coupling" - the point where the Local EPS is connected to the Company's system.

ix) "Quick Closed" - a method of generation transfer that parallels for less than 100 msec with the Company and has utility grade timers that limit the parallel duration to less then 100 msec with the Company.

x) "Quick Open" - a method of generation transfer that does not parallel with the Company and has a brief open interval, typically about 100 msec.

xi) "Soft Loading Transfer" - a method of generation load transfer that parallels for typically less than 2 minutes to gradually transfer load between the generator and the Company.

xii) "Transmission System" - those facilities as defined by using the guidelines established by FERC.

xiii) "Type-Certified" - Generation paralleling equipment that is listed by an OSHA listed national testing laboratory as having met the applicable type-testing requirements of IEEE 1547.1, such as UL 1741. This definition does not preclude other forms of type-certification if agreeable to the Company Operator. "Type-Certified" is the same as "pre-certified" and "certified" when used in this text.

B) Interconnection Requirements Goals

This standard defines the minimum technical requirements for the implementation of the electrical interconnection between the Generation System and the Company. 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.

C) 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 Company 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 Company's system.

D) Company Modifications

Depending upon the match between the Generation System, the Company, and how the Generation System is operated, certain modifications and/or additions may be required to the existing Company system with the addition of the Generation System. To the extent possible, this standard describes the modifications that could be necessary to the Company facilities 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 Company Operator. In these cases, the Company Operator will provide the final determination of the required modifications and/or additions. If any special requirements are necessary, the Company Operator will identify them during the application review process.

E) Generation System Protection

The Interconnection Customer is solely responsible for providing protection for the Generation System. Protection systems required in this standard are structured to protect the Company'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 Company. The Company does not assume responsibility for protection of the Generation System equipment or of any portion of the Local EPS.

F) Electrical Code Compliance

The Interconnection Customer 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. The Company will require proof of complying with the National Electrical Code before the interconnection is made through installation approval by an electrical inspector.

The Interconnection Customer's Generation System and installation shall comply with latest revisions of the ANSI/IEEE standards applicable to the installation, especially IEEE 1547; "Standard for Interconnecting Distributed Resources with Electric Power Systems" and IEEE 1547.1 – 1547.6. See the reference section in this document for a partial list of the standards that 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 519-1992, "IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

IEEE Std 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems".

IEEE Std 1547.1-2005, "IEEE Standard Conformance Test Procedures for Equipment 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 142-1991, "IEEE Recommended Practice for Grounding of Industrial an Commercial Power Systems – Green Book",

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 C2-2002, 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 Company can vary. Most transfer systems normally operate using one of the following five methods of transferring the load from the Company 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) Open Transition (Break-Before-Make) Transfer Switch – With this transfer switch, the load to be supplied from the Distributed Generation is first disconnected from the Company 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 Company 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 Company. 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 500 kW.

This is due to possible voltage flicker problems created on the Company when the load is removed from or returned to the Company source. Depending up the Company system's stiffness, this level may be larger or smaller than the 500 kW level.

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

ii) Quick Open Transition (Break-Before-Make) Transfer Switch – The load to be supplied from the Distributed Generation is first disconnected from the Company 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 Company 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 500 kW. This is due to possible voltage flicker problems created on the Company, when the load is removed from or returned to the Company source. Depending up the Company system's stiffness, this level may be larger or smaller than the 500 kW 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 Company before the transfer occurs. The transfer switch then parallels with the Company for a short time (100 msec. or less) and then the Generation System and load is disconnect from the Company. 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 Company is lost. With this type of transfer, the load is always being supplied by the Company or the Distributed Generation.

(1) As a practical point of application, this type of transfer switch is typically used for loads less then 500 kW. This is due to possible voltage flicker problems created on the Company, when the load is removed from or returned to the Company source. Depending up the Company system's stiffness, this level may be larger or smaller than the 500 kW 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 Company for a limited amount of time (generally less then 1-2 minutes) to gradually transfer the load from the Company 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 provides a typical one-line diagram of this type of installation and shows the required protective elements.

(2) With Extended Parallel Operation – The Generation System is paralleled with the Company in continuous operation. Special design, coordination, and agreements are required before any extended parallel operation will be permitted. The Company 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 diagram for this type of interconnection. It must be emphasized that these are 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 Company. Solar, wind, and fuel cells are some examples of Generation that typically use inverters to connect to the Company. Either these inverters shall contain all necessary protection to prevent unintentional islanding or the Interconnection Customer 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 – Before 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 Company 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 Company system.

(3) A visible, lockable loadbreak disconnect switch is required for safety to isolate the Distributed Generation. 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 Company must be preformed to determine any additional protection systems, metering, or other needs. The issues will be identified by the Company during the interconnection study process

4. Interconnection Issues and Technical Requirements

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

i) Visible, Lockable Loadbreak Disconnect Switch - A disconnecting device shall be installed to electrically isolate the Company from the Generation System. The only exception for the installation of a visible, lockable loadbreak 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, lockable loadbreak disconnect shall provide a visible air gap between Interconnection Customer's Generation and the Company in order to establish the safety isolation required for work on the Company system. This disconnecting device shall be readily accessible 24 hours per day by the Company field personnel and shall be capable of padlocking by the Company field personnel. The disconnecting device shall be lockable in the open position. In general, the device is not considered accessible if site personnel must be contacted or used to access and/or operate the device.

The visible, lockable loadbreak 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. A draw-out type circuit breaker can be used as a visual open as long as it meets the Company field personnel accessibility requirement.

The visible disconnect shall be labeled, as required by the Company Operator to inform the Company field personnel.

ii) Energization of Equipment by Generation System – The Generation System shall not energize a de-energized Company system. The Interconnection Customer 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 Company system.

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

(1) Inverter Based interconnections – for 20 kW and less, shall operate at a power factor of no less then 90% at the inverter terminals. Facilities over 20 kW shall meet the extended parallel requirements.

(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 Company 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 operate near unity power factor (+/-98%) or as mutually agreed between the Company Operator and the Interconnection Customer.

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) It is the responsibility of the Interconnection Customer to provide the required grounding for the Generation System. A good standard for this is the IEEE Std. 142-1991 "Grounding of Industrial and Commercial Power Systems"

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

v) Sales to Company 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 Company 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 Company system 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 Company, the Generation System shall meet the Voltage, Frequency, Harmonic and Flicker operating criteria as defined in IEEE 1547 and IEEE 519 standards during periods when the Generation System is operated in parallel with the Company.

If the Generation System creates voltage changes greater than 4% on the Company system, it is the responsibility of the Interconnection Customer 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 customer's interconnected to the Company, the Interconnection Customer is responsible for correcting the problem.

iii) Flicker - The operation of the Generation System is not allowed to produce excessive flicker to adjacent customers. See IEEE 1547 and IEEE 519 standards for a more complete discussion on this requirement.

The stiffer the Company system, the larger a block load change that it will be able to handle. For any of the transfer systems, the Company voltage shall not drop or rise greater than 4% when the load is added or removed from the Company. 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 Interconnection Customer'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 Company system.

iv) Interference - The Interconnection Customer shall disconnect the Distributed Generation from the Company if the Distributed Generation causes radio, television, or electrical service interference to other customers, via the distribution system or interference with the operation of the Company's system. The Interconnection Customer either shall effect repairs to the Generation System or reimburse the Company Operator for the cost of any required modifications address 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 Company system, it is required that the synchronizing equipment be capable of closing the Distributed Generation into the Company system within the limits defined in IEEE 1547. 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 Company's system to be disconnected from the rest of the Company's system 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 Company's system 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 Company's system immediately by protective relays for any condition that would cause the Company's system 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 Company's system until the Company's system is reenergized and the 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 Company's source(s) to remotely trip the generation interconnection to prevent islanding for certain conditions

vi) Disconnection – the Company Operator may refuse to connect or may disconnect a Generation System from the Company 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 Company personnel (Safety).

(5) Routine maintenance, repairs, and modifications to the Company. The Company Operator shall coordinate planned outages with the Interconnection Customer to the extent practical.

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 summarizes the metering, monitoring, and control requirements.

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

Another factor that will effect the metering, monitoring, and control requirements will be the tariff under which the Interconnection Customer is supplied by the Company. Table 5A has been written to cover most application but some Company tariffs may have greater or lesser metering, monitoring, and control requirements than 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
< 20 kW with all sales to Company	Bi-Directional metering at the point of common coupling**	None Required	None Required
20 – 250 kW with limited parallel	Detented* Company Metering at the Point of Common Coupling	None Required	None Required
20 – 250 kW with extended parallel	Recording metering on the Generation System and a separate recording meter on the load	Interconnection Customer supplied direct dial phone line. Company to supply it's own monitoring equipment	None Required
250 – 1000 kW With limited parallel	Detented* Company Metering at the Point of Common Coupling	Interconnection Customer 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 Company remote monitoring system See B (i)	None Required
>1000 kW With limited parallel Operation	Detented* Company Metering at the Point of Common Coupling	Required Company 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 Company SCADA monitoring system See B (i)	Direct Control via SCADA by Company of interface breaker.

* "Detented" - A meter that is detented will record power flow in only one direction.

** Meter will be detented unless a specific Company tariff permits net metering and the Interconnection customer has arranged for this service.

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 Company 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 Company's use to read the metering. Some monitoring may be done through the meter and the dedicated, direct dial phone line. In many installations, the remote monitoring and the meter reading can be done using the same dial-up phone line. The actual metering configuration and meters installed will be in accordance with the application and the tariffs that apply to the facility.

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

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

iv) An additional, separate meter may be required to record energy for renewable energy credit (REC) payments. This will be determined by the present tariffs on file and approved by the Commission.

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 Company's system. 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 Company 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 Company's service to the facility.

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

(4) Customer load from Company service (kW and kVAr).

(5) Control of interconnection breaker - if required by the Company Operator.

When telemetry is required, the Interconnection Customer must provide the communications medium to the Company's Control Center. This could be radio, dedicated phone circuit, or other form of communication. If a telephone circuit is used, the Interconnection Customer must also provide the telephone circuit protection. The Interconnection Customer shall coordinate the RTU (remote terminal unit) addition with the Company. The Company 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 Company 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. The relaying requirements illustrated are typical requirements. Additional requirements may be needed to accommodate the Facility. Additional requirements are likely where the Facility size is large compared to the system capacity and short circuit strength.

If a transfer system is installed that 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.

The Interconnection Customer shall provide protective devices and systems to detect the Voltage, Frequency, Harmonic, and Flicker levels as defined in the IEEE 1547 standard during periods when the Generation System is operated in parallel with the Company. The Interconnection Customer 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.

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

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. Installations 20 kW and under utilizing Type-Certified interconnection equipment are exempt from this requirement. The Company may waive compliance with this requirement for larger installations utilizing Type-Certified equipment in some situations.

(3) Three phase interconnections shall utilize three-phase power relays that monitor all three phases of voltage and current, unless otherwise 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 and meet other requirements as specified in the Company 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.

(a) <u>Over-current relays</u> (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 Company's system. 51V is a voltage restrained or controlled over-current relay and may be required to provide proper coordination with the Company.

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

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

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

(e) Under-frequency relay (IEEE Device 81U) shall operate to trip the Distributed Generation off-line per the requirements of IEEE 1547. For Generation Systems with an aggregate capacity greater then 20 kW, 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 Company is required for this setting.

The Company 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 Company) 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 de-energized 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 Company when the Company's system is disconnected from its source to avoid unintentional islanding. With larger Generation Systems, which remain in parallel with the Company, a transfer trip system may be required to sense the loss of the Company source. When the Company source is lost, a signal is sent to the Generation System to separate the Generation from the Company. The size of the Generation System versus the capacity and minimum loading on the feeder will dictate the need for a transfer trip installation. The Company interconnection study will identify the specific requirements.

If multiple Company sources are available or there are multiple points of sectionalizing on the Company system, then more than one transfer trip system may be required. The Company interconnection study will identify the specific requirements. For some installations, the alternate Company source(s) may not be utilized except in rare occasions. If this is the situation, the Interconnection Customer may elect to have the Generation System locked out when the alternate source(s) are utilized if agreeable to the Company 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 100 ms 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 >250 kW (Fig. 4)	Yes	Yes	Yes	—	Yes	—	Yes	Yes
Inverter Connection (Fig. 5)								
< 20 kW	Yes	Yes	Yes	—	Yes	—	—	—
20 kW – 250 kW	Yes	Yes	Yes	—	Yes	—	—	—
> 250 kW	Yes	Yes	Yes	—	Yes	—	—	Yes

7. Agreements

A) <u>Interconnection Agreement</u> – This agreement is required for all Generation Systems that parallel with the Company. There may be 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 Company. 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 Company 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 larger Generation Systems that normally operate in parallel with the Company, an agreement separate from the interconnection agreement, called the "operating agreement", is usually created. This agreement is created for the benefit of both the Interconnection Customer and the Company 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 integrated 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 Customer's and Company's systems. The items typically included in the operating agreement are as follows;

i) Emergency and normal contact information for both the Company operations center and for the Interconnection Customer.

ii) Procedures for periodic Generation System test runs.

iii) Procedures for maintenance on the Company system that affect the Generation System.

iv) Emergency Generation Operation Procedures.

8. Testing Requirements

A) Pre-Certification of Equipment

The most important part of the process to interconnect generation with Customer's and Company's systems is safety. One of the key components of ensuring the safety of the public and employees is to ensure that the design and implementation of the elements connected to the electrical power system operate as required. To meet this goal, all of the electrical wiring in a business or residence is required to be listed by a recognized testing and certification laboratory for its intended purpose. Typically, we see this as "UL" listed. Since Generation Systems have tended to be uniquely designed for each installation, they have been designed and approved by Professional Engineers. As the number of Generation Systems installed increase, vendors are working towards creating equipment packages that can be tested in the factory and then will only require limited field testing. This will allow us to move towards "plug and play" installations. For this reason, this standard recognizes the efficiency of "pre-certification" of Generation System equipment packages that will help streamline the design and installation process.

An equipment package shall be considered certified for interconnected operation if it has been submitted by a manufacture to and tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous utility interactive operation in compliance with the applicable codes and standards. The applicable type-testing requirements are given in IEEE 1547.1. An "equipment package" shall include all interface components including switchgear, inverters, or other interface devices and may include an integrated generator or electric source. If the equipment package has been tested and listed as an integrated package that includes a generator or other electric source, it shall not required further design review, testing, or additional equipment to meet the certification requirements for interconnection. If the equipment package includes only the interface components (switchgear, inverters, or other interface devices), then the Interconnection Customer shall show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and consistent with the testing and listing specified for the package. Provided the generator or electric source combined with the equipment package is consistent with the testing and listing performed by the nationally recognized testing and certification laboratory, no further design review, testing, or additional equipment shall be required to meet the certification requirements of this interconnection procedure. A certified equipment package does not include equipment provided by the Company.

The use of Pre-Certified equipment does not automatically qualify the Interconnection Customer to be interconnected to the Company. 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 Company's system.

B) Pre-Commissioning Tests

i) Non-Certified Equipment

Pre-commissioning testing and Commissioning testing are also covered in IEEE 1547.1.

(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 Company system.

(b) The Generation may not close into a de-energized Company system and protection must be provided to prevent this from occurring. It is the Interconnection Customer's responsibility to provide a final design and to install the protective measures required by the Company. The Company 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 Interconnection Customer obtain Company written approval before ordering protective equipment for parallel operation. The Interconnection Customer will own these protective measures installed at their facility.

(c) The Interconnection Customer shall obtain prior approval from the Company for any revisions to the specified relay calibrations.

C) Commissioning Testing

The following tests shall be completed by the Interconnection Customer. All of the required tests in each section shall be completed prior to moving on to the next section of tests. The Company 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 Company shall be notified with sufficient lead time to allow the opportunity for Company 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 Company. 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

Company Operator.

(6) Trip Checks - Protective relaying shall be 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 before energization. Where appropriate, those points may be verified during the energization process.

(8) Phase Tests – the Interconnection Customer shall work with the Company 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 an 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 Company 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 as stated in IEEE 1547 and 1547.1. This test shall also demonstrate that if 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) <u>On-Line Commissioning Test</u> – the following tests will proceed once the Generation System has completed Pre-testing and the results have been reviewed and approved by the Company Operator. For 20 kW and under Generation Systems, the Company may waive joint interconnection tests. On larger and more complex Generation Systems, the Interconnection Customer and the Company Operator will get together to develop the required testing procedure. All on-line commissioning tests for larger facilities shall be based on written test procedures agreed to between the Company Operator and the Interconnection Customer.

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 100 msec

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

(b) The Company 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 Company source shall be closed and the Generation System shall not re-parallel with the Company for at least 5 minutes.

iii) <u>Final System Sign-off</u>

(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 prior to the installation being considered ready for commercial use.

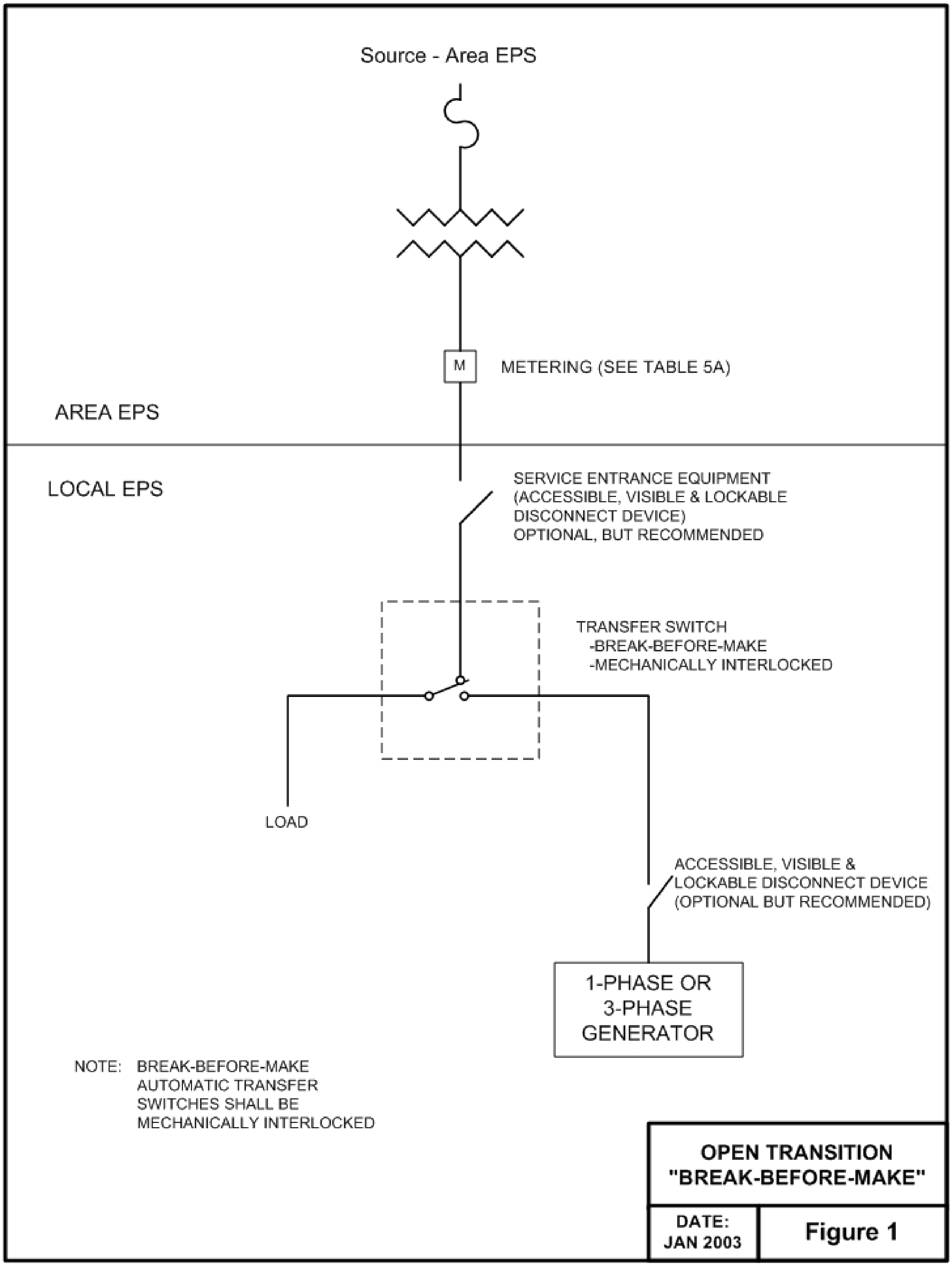
iv) Periodic Testing and Record Keeping

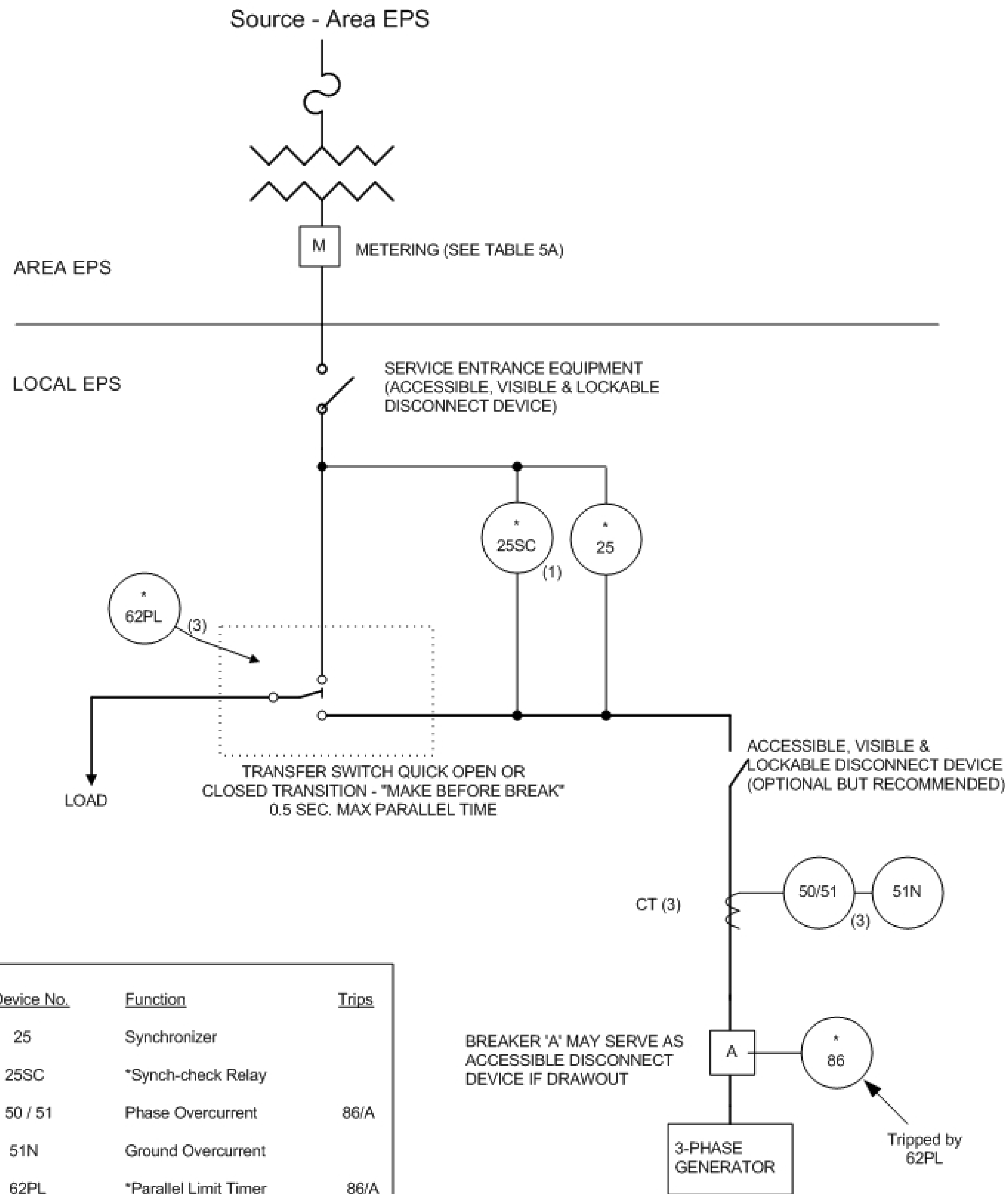
(1) Any time the interface hardware or software, including protective relaying and generation control systems are replaced and/or modified, the Company Operator shall be notified. This notification shall, if possible, be with sufficient warning so that the Company personnel can be involved in the planning 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 Company personnel will depend upon the complexity of the Generation System and the component being replaced and/or modified. Since the Interconnection Customer and the Company 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 Customer's and Company's systems.

(2) All interconnection-related protection systems shall be periodically tested and maintained by the Interconnection Customer 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 Interconnection Customer and made available to the Company Operator upon request. The Company Operator shall be notified before the periodic testing of the protective systems so that Company personnel may witness the testing if so desired. Testing notification for Facilities 20 kW and under is not required.

(a) Verification of inverter connected system rated 20 kW and below may be completed as follows: The Interconnection Customer shall operate the AC 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, either the battery(s) must be replaced or a discharge test performed. Longer intervals are possible with "station class batteries" and Company Operator approval.


Source - Area EPS
M
METERING (SEE TABLE 5A)
AREA EPS
LOCAL EPS
SERVICE ENTRANCE EQUIPMENT
(ACCESSIBLE, VISIBLE & LOCKABLE
DISCONNECT DEVICE)
OPTIONAL, BUT RECOMMENDED
TRANSFER SWITCH
-BREAK-BEFORE-MAKE
-MECHANICALLY INTERLOCKED
LOAD
ACCESSIBLE, VISIBLE &
LOCKABLE DISCONNECT DEVICE
(OPTIONAL BUT RECOMMENDED)
1-PHASE OR
3-PHASE
GENERATOR
NOTE: BREAK-BEFORE-MAKE
AUTOMATIC TRANSFER
SWITCHES SHALL BE
MECHANICALLY INTERLOCKED
OPEN TRANSITION
"BREAK-BEFORE-MAKE"
DATE:
JAN 2003
Figure 1



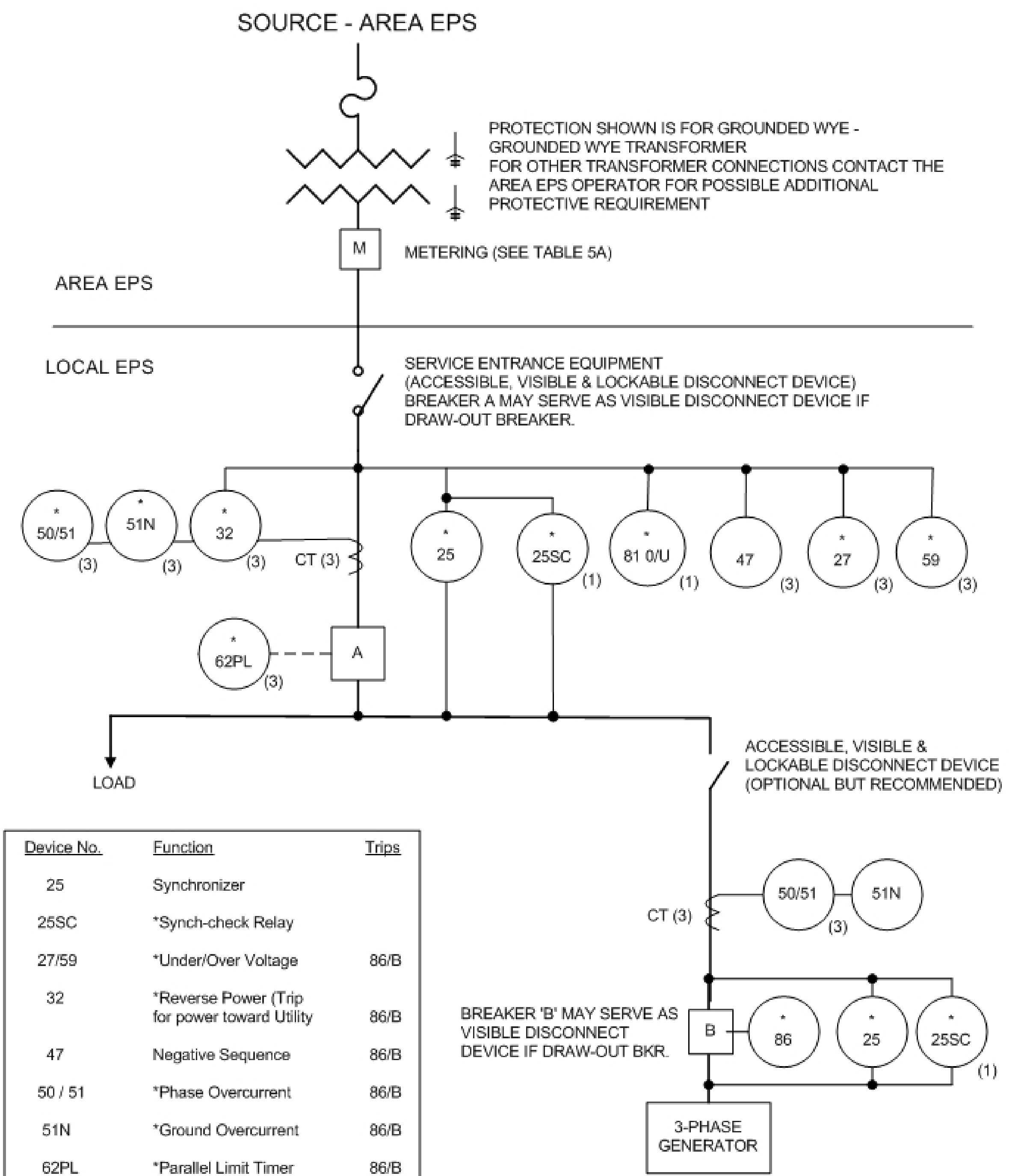
Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
50 / 51	Phase Overcurrent	86/A
51N	Ground Overcurrent	
62PL	*Parallel Limit Timer	86/A
86	*Lockout Relay	A

(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**



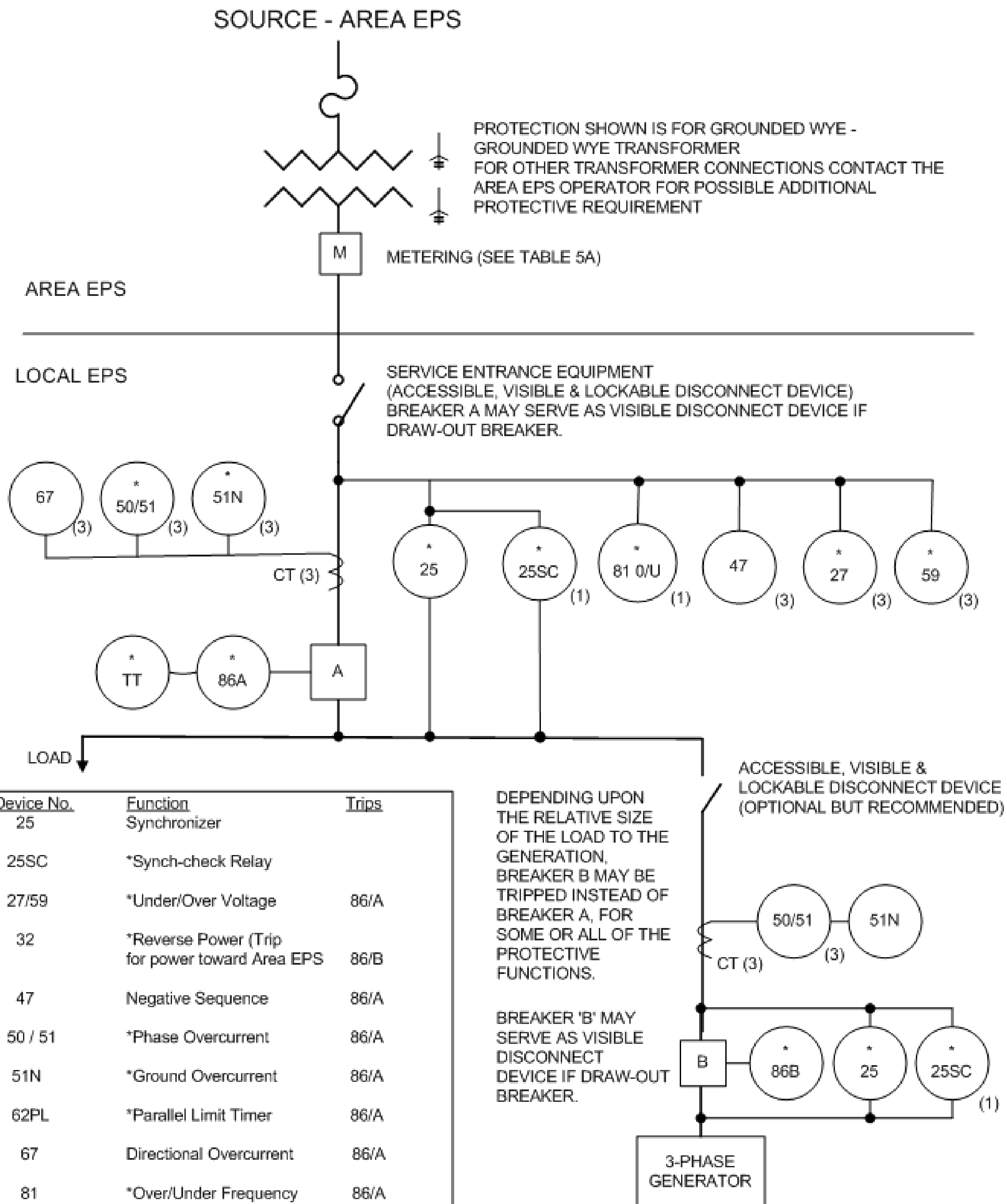
Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
27/59	*Under/Over Voltage	86/B
32	*Reverse Power (Trip for power toward Utility	86/B
47	Negative Sequence	86/B
50 / 51	*Phase Overcurrent	86/B
51N	*Ground Overcurrent	86/B
62PL	*Parallel Limit Timer	86/B
81	*Over/Under Frequency	86/B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

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

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

SOFT LOADING TRANSFER LIMITED PARALLEL OPERATION

DATE: JAN 2003	**Figure 3**



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

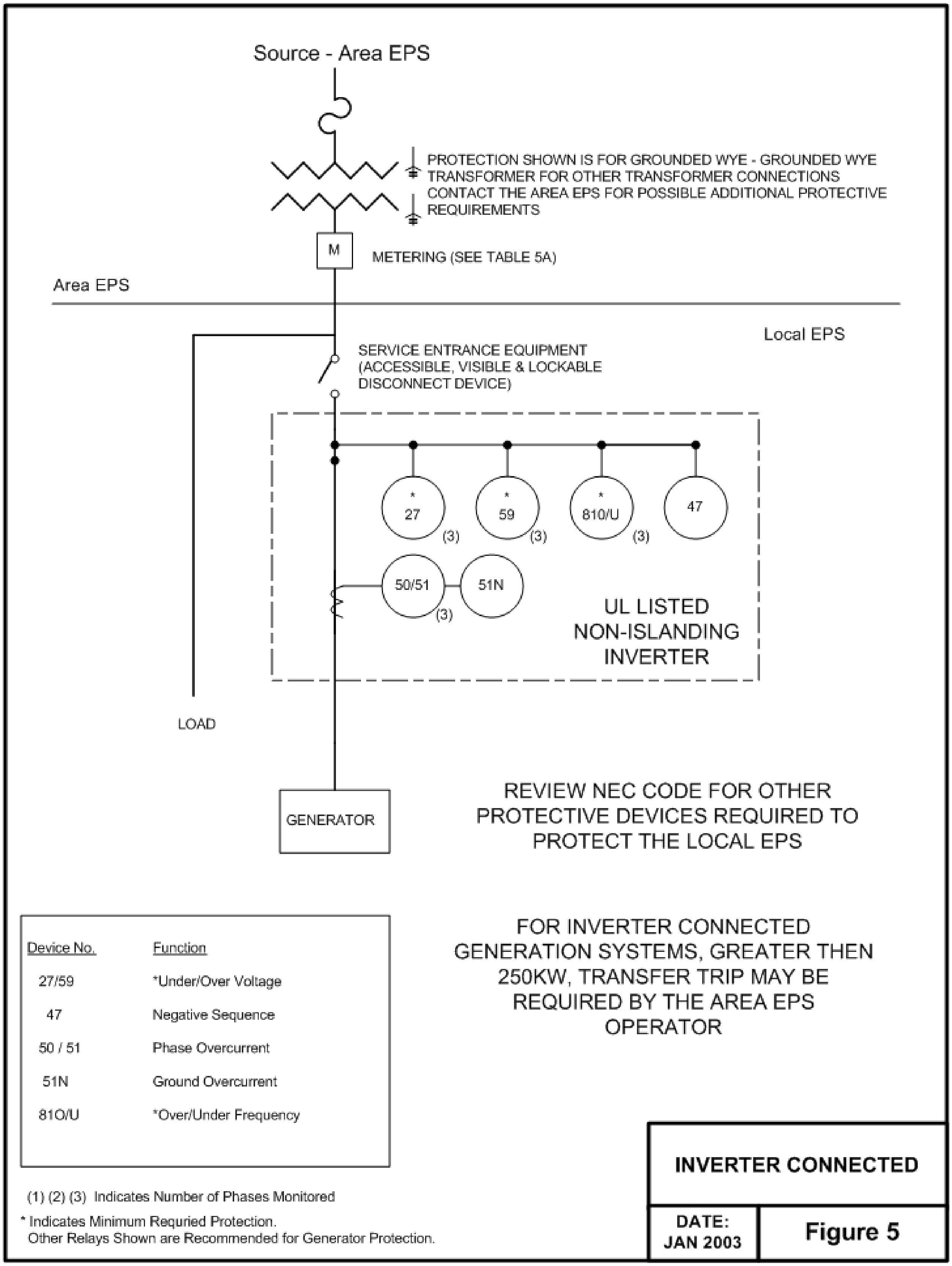
(1) (2) (3) Indicates Number of Phases Monitored

* 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)
* 810/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

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dakota
Unadjusted Test Year
Service Charge Cost Analysis

Service Processing Charges Section 6.1.2	Costs		
Description	**Processing Charge**	**Reconnects (1)**	**Relock (2)**
Customer Call Center (CCC)			
Call Center reps to process service application	$ 2.75	$ -	$ -
Administrative charge to process service application	$ 1.80	$ -	$ -
Call Center reps to lock	$ -	$ 2.75	$ 2.75
Administrative charge to lock	$ -	$ 1.80	$ 1.80
Call Center reps to unlock	$ -	$ 2.75	$ -
Administrative charge to unlock	$ -	$ 1.80	$ -
Call Center reps to relock	$ -	$ -	$ 2.75
Administrative charge to relock	$ -	$ -	$ 1.80
Credit Field Calls (lock)			
Vehicle charge to lock	$ -	$ 2.66	$ 2.66
Labor needed to Lock Meter (Credit)	$ -	$ 15.00	$ 15.00
Credit Field Calls (unlock)			
Vehicle charge to unlock	$ -	$ 2.66	$ -
Labor needed to Unlock Meter (Credit)	$ -	$ 15.00	$ -
Vehicle charge to verify/relock	$ -	$ -	$ 2.66
Labor needed to verify/relock Meter (Credit)	$ -	$ -	$ 15.00
Travel to UNLOCK or RELOCK	$ -	$ 2.85	$ 5.70
Producing bill	$ 0.10	$ 0.10	$ 0.10
Mailing bill	$ 0.28	$ 0.28	$ 0.28
New customer packet cost	$ 0.90	$ -	$ -
Call Center IT costs per call	$ 0.36	$ 0.36	$ 0.36
Cost Per Transaction	**$ 6.19**	**$ 48.01**	**$ 50.86**

NOTES:

Note 1: The cost for reconnecting service which has been disconnected for non-payment.

Note 2: The cost for reconnecting service where Xcel Energy has disconnected service for non-payment and subsequently returned to relock the service after it was reconnected without Xcel Energy's authorization.

TARIFF	Current Tariff Charge	2008 Costs	Proposed Tariff Charge
Service Processing Charge	$ 12.00	$ 6.19	**$ 12.00**
Service Reconnection Charge	$ -	$ 48.01	**$ 22.50**
Service Relock Charge	$ -	$ 50.86	**$ 100.00**

Dedicated Switching Service Section 6.1.8 Description	Straight time 2008 $/call	Overtime Mon-Sat x 1.5% $/call	Overtime Sun-Fed Holidays x 2.0% $/call
Dispatching labor cost	$3.28	$4.92	$9.84
Trouble person labor per job	$143.70	$215.55	$287.40
Administrative @ 5% of Trouble person labor	$7.19	$10.78	$14.37
Sub total labor	**$154.17**	**$231.25**	**$311.62**
Trouble truck	$37.59	$37.59	$37.59
Total Trouble Costs	**$191.76**	**$268.84**	**$349.21**
Call Center labor cost per call	$2.75	$2.75	$2.75
Call Center IT costs per call	$0.36	$0.36	$0.36
Producing bill	$0.10	$0.10	$0.10
Postage for bill	$0.28	$0.28	$0.28
Total Billing Costs	**$3.49**	**$3.49**	**$3.49**
TOTAL COSTS	**$195.25**	**$272.33**	**$352.70**

TARIFF	Charge Per Person Per Hour		
Requested Appointment Date	**Current Tariff Charge**	**2008 Costs**	**Proposed Tariff Charge**
Monday through Saturday	$0.00	$272.33	**$250.00**
Sunday and federally observed holidays	$0.00	$352.70	**$300.00**

Account History Charge	
Section 6.3.10	
Description	**Minimum 10 Accounts**
Handling - printing	$ 32.27
Handling - stuffing envelopes	$ 6.45
Postage for histories	$ 0.99
Miscellaneous (paper, ink, etc.)	$ 0.02
Call Center labor cost per call	$ 2.75
Call Center IT costs per call	$ 0.36
Billing labor costs	$ 7.02
Producing bill	$ 0.10
Postage for bill	$ 0.28
Total Costs per request involving 10 accounts	**$ 50.24**
$/Account, minimum 10 accounts/request	**$ 5.02**

TARIFF	Current Tariff Charge	2008 Costs	Proposed Tariff Charge
Per account when the request involves 10 or more accounts	$ 1.00	$ 5.02	**$ 5.00**

Excess Footage Section 6.5.1.A1.				
Task	**Passport costs per circuit foot**	**Overhead**	**Overhead Costs**	**Proposed Tariff Charge per circuit foot**
Services	$ 5.35	28.13%	$1.50	**$6.85**

An analysis of projects was conducted using the Company's Passport System. Passport lists the field costs related to material, equipment, transportation, and labor costs of a construction project. The average cost for excess residential footage was $5.35 per circuit foot, less overhead.

The overhead rate of 28.13% applies for Engineering and Supervision costs associated with the construction project including labor costs for designers, engineers, and management. This is added to the Passport field cost, which results in $6.85 per circuit foot.

Winter Construction		
Section 6.5.1.A.2		
Proposed Tariff Charge		
Thawing	**$ 400.00**	**per frost**
Service, Primary, or Secondary distribution extension	**$ 3.00**	**per foot**

Frost burner	# of Burners	Propane Costs	Average Propane $	Construction $	Average Construction $	Loading Factor	Cost/Burner
Setting Tankers	103	$3,479.34	$33.78	$7,846.21	$76.18	$183.59	$217.37
Retanking Burners	111	$3,749.58	$33.78	$4,707.26	$42.41	$102.20	$135.98
Removing Burners	104	$0.00	$0.00	$7,714.72	$74.18	$178.77	$178.77
						241%	
					Adjusted cost/job		**$532.12**

Electric winter construction costs	Estimated Actual Costs per Electric Job	Proposed Tariff Charge
Service extension fixed $/job (or per frost burner)	$532.12	$ 400.00
Cost per Foot Trench	$ 3.00	$ 3.00
Average trench job of 40 foot	$ 120.00	$ 120.00
$/Second burner @ 10% of jobs	$ 53.21	$ 40.00
Call Center-Billing related tasks/job	$ 10.51	$ 10.51
Estimated Cost per job	**$ 718.84**	**$ 573.51**

The loading factor is the sum of overhead charges that pertain to the winter construction tasks relating to frost burners including: pension, insurance, taxes, workers compensation, non-productive time of vacation, sick leave, training, meetings, contract labor, etc. This applies only to Construction costs.