STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion,	)	
of the interconnection of merchant plants with	)	Case No. U-12485
the transmission and distribution systems	)	
of electric utilities.	)	
	)	

PROPOSED MERCHANT PLANT INTERCONNECTION STANDARDS OF MICHIGAN ELECTRIC AND GAS ASSOCIATION

The attached standards are filed by the Michigan Electric and Gas Association (MEGA), pursuant to the Commission's February 5, 2001 Opinion and Order. These proposed standards represent the joint work product of a team of representatives from the following MEGA member electric utilities: Alpena Power Company, American Electric Power (Indiana Michigan Power Co.), Edison Sault Electric Company, Upper Peninsula Power Company, Wisconsin Electric Power Company, Wisconsin Public Service Corporation and Xcel Energy (f/k/a Northern States Power Company).

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Response to February 5, 2001 Order of the Michigan Public Service Commission

Case No. U-12485

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1.0 INTRODUCTION

The Michigan Public Service Commission (MPSC) issued an Order on February 5, 2001 relating to Case No. U-12485. The Order instructed utilities to file, within 90 days, draft proposed interconnection standards for merchant plant interconnections with utility Transmission and Distribution systems consistent with the Order. This document is the response to that Order by members of the Michigan Electric and Gas Association (MEGA).

Any interconnection requirements developed by the MPSC should only apply to new applications for interconnection. It must be recognized that existing interconnections have been made under a variety of individual companies' past requirements. These existing installations should be exempt from new requirements, or "grandfathered". Generators increasing output capability greater than 10% of contract capacity at existing facilities must provide notification to the distribution company. The utility will determine if this change in operation will require a formal application and review process as outlined in the new requirements. Generators that will have a significant sustained reduction in output capability will also require notification to the distribution company.

MEGA recognizes that there are technical challenges from the systems interconnection itself and also associated business related (fees, billing, response times, operating agreements, etc.) challenges. This document attempts to cover both sets of concerns for interconnection to utility distribution systems. However, this document does not cover commercial issues and concerns relating to the sale of power or ancillary services when the interconnected customer generator exports power across the point of common coupling and into the distribution system. It is the opinion of MEGA members that requirements for interconnection to utility transmission systems are already outlined in the Open Access Transmission Tariffs (OATTs) that have already been filed.

The business related challenges that will be required between the generator, the local utility, and any third parties can be complex and we only try to make the Commission aware of some of the points to be considered. Solutions and methodologies will be unique to individual utilities, depending on corporate structure and business strategy. A broad overview of the points to consider is contained in Section 3.

The technical challenges are not unique to merchant plants and are more common to the industry as a whole. These issues will arise from any proposed interconnection of distributed generation (DG) that will operate in parallel with the local utility system. Because of this, the sections of this document addressing technical issues are recommended for **any** new generating facility or significant addition to an existing facility interconnected to a utility distribution system and not just merchant plants.

2.0 DEFINITIONS

Distributed Generation (DG)- Includes any distribution connected generators such as on-site distributed generation facilities, self generators, small electric generation facilities and electric customer-generators.

Distributed Generation (DG) Equipment – Includes any distribution connected generator facility such as a distributed generation facility, small electric generation facility, or generation facility of a self-generator or customer generator.

Facilities Study - An engineering study conducted to determine the modifications to the existing utility system that will be required to accommodate the requested interconnection.

Flicker – A variation of input voltage sufficient in duration to allow visual observation of a change in electric light source intensity.

Harmonic Distortion – Continuous distortion of the normal sine wave; typically caused by nonlinear loads or by inverters.

Networked System - One that is normally operated with more than one distribution feeder connected to a load. Examples are spot networks and secondary networks. Open loop underground residential distribution systems and open loop primary feeder systems are not considered networks in this context.

Point of Common Coupling – The point at which the distributed generation facility is connected to the shared portion of the utility system.

Radially Operated System – One that is normally operated with only one distribution feeder connected to a load at any one time.

Short Circuit Contribution – The result of dividing the maximum short circuit contribution of the distributed generator(s) by the short circuit contribution available from the utility system without distributed generator(s), converted to a percentage.

Single Phasing Condition – Occurs when one phase of the three-phase supply line is disconnected.

Supplemental Review - Review of functional technical requirements to determine acceptability of interconnection equipment.

System Impact Study - An assessment to determine the ability of the existing utility system to accommodate the requested interconnection request.

Unintentional Island - An unplanned condition where one or more DGs and a portion of the electric utility grid remain energized through the point of interconnection.

3.0 BUSINESS CHALLENGES

MEGA agrees with the MPSC on the importance of various aspects of generation interconnections.

Connections to a utility's transmission system will be subject to FERC jurisdiction and existing Open Access Transmission Tariffs (OATTs). It is recognized that various utilities define the line between transmission and distribution facilities differently. That should not have much bearing on the issue of jurisdiction, however. FERC should have jurisdiction, with MPSC review, of any interconnections to a company's transmission system, however defined. This should also address the MPSC concern of special treatment at higher voltages. Those higher voltages will be transmission facilities and requirements are outlined in the OATTs. The MEGA members believe facilities larger than 10 MW will have a profound effect on utility distribution systems and should fall under OATT guidelines also. The technical requirements outlined in this document are for interconnections to utility distribution systems, as defined by each utility and approved by the MPSC.

Applicants for interconnection should expect timely review of applications, prompt response regarding any necessary facility upgrades, and notification of expected service date for new facilities. We have tried to outline a screening process for expedited approval that considers the many types of applications that might be received and the various systems for which interconnection might be requested. Applications that satisfy the screening process should be approved and service provided promptly.

MEGA proposes a non-refundable application fee due at time of application. This nominal fixed fee ($100 for single-phase and $500 for three-phase) would be used to reimburse the utility company for the costs of locating the proposed facility and gathering information necessary to evaluate the screening process. Additionally, system impact studies might be required. The resources required to perform these studies will vary widely mostly dependent on the size of the proposed facility and the available capacity on the utility system to interconnect at the desired point. MEGA proposes that the system impact study cost be provided to the applicant upon notification that the completed application information has been received (within ten business days).

Any reasonable costs for required utility system upgrades due to the interconnection should be paid by the generator owner. The utility system should be evaluated from its condition at the time of the interconnection application. Applications will be evaluated in the order received. It will be possible that future application for a similar size generator in proximity of an earlier interconnection will require different system improvements because of the altered state of the utility system resulting from the first interconnection.

The local utility and nearby utility customers will be affected by any generation interconnection. Although there are potential benefits to utilities from generation interconnections in the right locations, it should be recognized that there are increased risks of damaged equipment to all parties. The utility and generation owner should have clearly stated roles in liability protection.

Each utility should be required to develop Distribution – Generation Interconnection Agreements (D-G IA) outlining the roles of each party in the interconnection. Various relationships will be required if the merchant plant is selling to another customer on the same distribution circuit, the same distribution station, the same distribution system, or to another customer via a common transmission connection. Agreements between these parties could include negotiated pricing, invoicing and payment, time of availability, maintenance notifications, inspection schedules, rights of access, termination requirements, liability protection, energy imbalance requirements and process, metering and communication requirements, Control Area operating requirements, and the buyer of last resort among other things.

The utility should be permitted to accept energy produced by a merchant plant or DG, but the utility should not be required to pay for the energy or any related capacity unless specifically identified in the interconnection agreement or a separate purchase agreement has been executed. The utility should not be designated as the buyer of last resort and forced to buy at avoided cost.

It should be recognized that the MPSC and utilities share a need to blend any new ratemaking with existing customer owned generator requirements. How will application and study fees be implemented with respect to existing rate structures? Can new fees be addressed outside a rate case via a specific application by each utility or must they be addressed in a rate case filing? What will be the procedure for updating any fee structures? How does the MPSC view the process to integrate and reconcile any new rules with existing rules for generators such that existing generators are not unduly restricted by new rules?

4.0 APPLICATION PROCESS FOR ALL INTERCONNECTIONS

A customer desiring interconnection to the Company's distribution system must submit to the Company a completed interconnection application form along with the proper Application Fee. A queuing process will be in place such that applications are considered in the order in which they are received. The Company shall charge each customer that applies for interconnection an Application Fee of $100 for single-phase installations and $500 for three-phase installations, payable at the time the application is submitted. An application fee is required for each proposed installation on the Company's distribution system. This fee is not to preclude any fees or charges that may be imposed by third-party providers (i.e., transmission and other distribution companies) or by the Company relating to the export of power from the customer's generation across the point of common coupling and into the Company's distribution system.

The Company will provide such customer a written notice within five business days of the Company's receipt of the customer's interconnection application stating that the Company has received and will begin to process the application. If the application is viewed as incomplete, the Company will provide written notice within ten days of the receipt of the application that the application is not complete along with a description of the information needed to complete the application. If the application is complete, the Company will notify the applicant and the notification will include the amount of the proposed system impact study fee within the ten-day period.

Study fees may be required to cover the cost of a system impact study to determine the feasibility and cost of safely connecting the customer's generation facilities to the Company's distribution system. The impact study time will vary widely, mostly depending on the size of the proposed generation and the location of the interconnection. The study should be utility commissioned and the fee will be outlined on a case-by-case basis proposed with the application review. Such fees shall be paid in advance and apply to each installation at the Company's distribution voltages.

Prior to actual interconnection, the Company shall provide a draft D-G IA to the customer. The utility and customer shall execute the D-G IA after any necessary modifications are mutually agreed upon to reflect the specific conditions of the proposed new facility.

Following execution of the D-G IA, to the extent possible, interconnection to the Company's distribution system shall take place within the following time frames:

> Where construction is not required by the Company, interconnection shall be permitted within four weeks of execution of the D-G IA.
>
> Where construction or upgrades of the Company's system are required, the Company shall provide the customer an estimate of the schedule and the customer's cost for the construction or upgrades. Should the customer desire to proceed with the construction or upgrades, the customer and the Company shall enter into a contract for the completion of the construction or upgrades. Assuming the customer is ready, interconnection shall take place no later than two weeks following the completion of such construction or upgrades.

The Company shall make every reasonable effort to complete such system construction or upgrades in the shortest time reasonably practical.

If the Company determines that it cannot connect the customer within the above time frames, the Company will notify the customer in writing of that fact as soon as possible. Such notification will identify the reason interconnection could not be completed within these time frames and will provide an estimated date of completion.

Requirements for Interconnection and Parallel Operation of Distributed Generation
Single-Phase less than or equal to 25kW
Three-Phase less than or equal to 500kW

APPLICABILITY

These rules apply to interconnection and parallel operation of DG (Distributed Generation) equipment that is rated 25kW or smaller single-phase and 500kW or smaller three-phase on radially operated, non-networked Company Distribution systems of 35kV or less.

5.0 CUSTOMER DESIGN REQUIREMENTS

For an interconnection to be safe to Company employees / equipment and to other customers, the following conditions are required to be met on DG equipment.

5.1 Customer DG facilities must meet all applicable national, state, and local construction, operation and maintenance related safety codes, such as National Electrical Code (NEC), National Electrical Safety code (NESC), Occupational Safety and Health Administration (OSHA).

5.2 Customer must provide the Company with a one-line diagram showing the configuration of the proposed DG system, including the protection and controls, disconnection devices, nameplate rating of each device, power factor rating, transformer connections, and other information deemed relevant by the Customer. If the proposed DG system does not pass the screening process for simplified interconnection, additional information may be necessary from the Customer and Company facilities changes may be required.

5.3 DG Equipment must be equipped with adequate protection and control to trip[1] the unit off line during abnormal[2] system conditions, according to the following requirements:

5.3.1 Undervoltage or overvoltage within the trip time indicated below. By agreement of both the DG operator and the Company, different settings maybe used for the under voltage and over voltage trip levels or time delays.

Voltage	Maximum Trip Time
V<50%	10 cycles
50%≤V<88%	120 cycles
110%<V<120%	60 cycles
V≥120%	6 cycles

[1] To trip is to automatically (without human intervention required) open the appropriate disconnection device to separate the DG equipment from the power system.

[2] Abnormal system conditions include faults due to adverse weather conditions including but not limited to, floods, lightning, vandalism, and other acts that are not under the control of the Company. This may also result from improper design and operation of customer facilities resulting from non-compliance with accepted industry practices.

5.3.2 For three-phase generation, loss of balanced three-phase voltage or a single-phasing condition within the trip times indicated in 1.3.1 when voltage on at least one phase reaches the abnormal voltage levels.

5.3.3 Underfrequency or overfrequency: All DG shall follow the associated Company frequency within the range 59.3 Hz to 60.5 Hz. DG $\leq$ 10 kW shall disconnect from the Company within 10 cycles if the frequency goes outside this range. A DG > 10kW shall (1) disconnect from the Company within 10 cycles if the frequency exceeds 60.5 Hz, and (2) be capable of time delayed disconnection for frequencies in the range 59.3 Hz to 57 Hz. By agreement of both the DG operator and the Company, different settings maybe used for the underfrequency and overfrequency trip levels or time delays.

5.4 DG equipment requires the following additional protection to avoid damage to the Company's system during normal, as well as abnormal system conditions.

5.4.1 Synchronizing controls to insure a safe interconnection with the Company's distribution system. The DG equipment must be capable of interconnection with minimum voltage and current disturbances. Synchronous generator installations, as well as other types of installations, must meet the following: slip frequency less than 0.2 Hz, voltage deviation less than $\pm$ 10%, phase angle deviation less than $\pm$ 10 degrees, breaker closure time compensation (not needed for automatic synchronizer that can control machine speed).

5.4.2 A disconnect switch to isolate the DG equipment for purposes of safety during maintenance and during emergency conditions. The Company may require a disconnect device to be provided, installed by, and paid for by the customer, which is accessible to and lockable by Company personnel, either at the primary voltage level, which may include load-break cutouts, switches and elbows, or on the secondary voltage level, which may include a secondary breaker or switch. The switch must be clearly labeled as a DG disconnect switch.

5.5 DG equipment must have adequate fault interruption and withstand capacity, and adequate continuous current and voltage rating to operate properly[3] with the Company's system. A three-phase device shall interrupt all three phases simultaneously. The tripping control of the circuit interrupting device shall be powered independently of the utility AC source in order to permit operation upon loss of the Company distribution system connection.

[3] Properly, in this context, means within the acceptable utility or applicable industry established practices.

5.6 Test results shall be supplied by the manufacturer or independent testing lab that verify, to the satisfaction of the Company, compliance with the following requirements contained in this document[4]:

5.3.1	Over/Under Voltage Trip Settings
5.3.3	Over/Under Frequency Trip Settings
5.4.1	Synchronization
5.7	Harmonic Limits (tested at 25%[5] and 100% of full load rating)
5.8	DC Current Injection Limits (Inverters)
5.13	Anti-Islanding (Inverters)
5.14	Prevent Connection or Reconnection to De-energized System

If test results are acceptable to the Company and if requested by a manufacturer, the Company will supply a letter indicating the protective and control functions for a specific DG model are approved for interconnection with the Company's distribution system, subject to the other requirements in this document.

The Customer must provide the Company a reasonable opportunity to witness site testing of any other protective and control functions required in this document, but not listed above. The Customer must provide the Company a reasonable opportunity to perform an inspection prior to the first paralleling of the generation equipment to install and/or verify correct protective settings and connections to the system.

5.7 Harmonics and Flicker: The DG equipment shall not be a source of excessive harmonic voltage and current distortion and/or voltage flicker. Limits for harmonic distortion (including inductive telephone influence factors) will be as published in the latest issues of ANSI/IEEE 519, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems." Flicker occurring at the point of compliance shall remain below the Border Line of Visibility curve on the IEEE/GE curve for fluctuations less than 1 per second or greater than 10 per second. However, in the range of 1 to 10 fluctuations per second, voltage flicker shall remain below 0.4%. Refer to Exhibit 1. When there is reasonable cause for concern due to the nature of the generation and its location, the Company may require the installation of a monitoring system to permit ongoing assessment of compliance with these criteria. The monitoring system, if required, will be installed at the DG owner's expense. Situations where high harmonic voltages and/or currents originate from the distribution system are to be addressed in the Interconnection Agreement.

5.8 DC Injection from inverters shall be maintained at or below 0.5% of full rated inverter output current into the point of common coupling.

[4] For photovoltaic systems, a certification that the testing requirements of UL 1741 have been met may be used in place of these tests.

[5] If the device is not designed to operate at this level, then the test should be at the lowest level at which it is designed to operate.

5.9 The Distributed Generation's generated voltage shall follow, not attempt to oppose or regulate, changes in the prevailing voltage level of the Company at the point of common coupling, unless otherwise agreed to by the operators of the Distributed Generation and the Company. Distributed Generation installed on the downstream (load) side of the Company's voltage regulators shall not degrade the voltage regulation provided to the downstream customers of the Company to service voltages outside the limits of ANSI 84.1, Range A

5.10 System Grounding: The DG system should be grounded in accordance with applicable codes. The interconnection of the DG equipment with the Company's system shall be compatible with the neutral grounding method in use on the Company's system. For interconnections through a transformer to Company system primary feeders of multi-grounded, four-wire construction, or to tap lines of such systems, the maximum unfaulted phase (line-to-ground) voltages on the Company system primary feeder during single line-to-ground fault conditions with the Company system source disconnected, shall not exceed those voltages which would occur during the fault with the Company system source connected and no DG equipment.

5.11 System Protection: The DG owner is responsible for providing adequate protection to Company facilities for conditions arising from the operation of generation under all Company distribution system operating conditions. The owner is also responsible for providing adequate protection to their facility under any Company distribution system operating condition whether or not their DG is in operation. Conditions may include but are not limited to:

1. Loss of a single-phase of supply,
2. Distribution system faults,
3. Equipment failures,
4. Abnormal voltage or frequency,
5. Lightning and switching surges,
6. Excessive harmonic voltages,
7. Excessive negative sequence voltages,
8. Separation from supply,
9. Synchronizing generation,
10. Re-synchronizing the Owner's generation after electric restoration of the supply.

5.12 Feeder Reclosing Coordination. In the case of a Company protection function initiating a trip of a Company protective device in reaction to a fault on the Company system, the DG unit protection and controls must be designed to coordinate with the Company reclosing practices of that protective device.

5.13 Unintentional islanding: For an unintentional island in which the DG and a portion of the Company's system remain energized through the point of common coupling, the DG shall cease to energize the Company's system within two seconds of the formation of an island.

5.14 The DG shall be designed to prevent the DG from being connected to a de-energized Company circuit. The customer should not reconnect DG to the Company's system after a trip from a system protection device, until the Company's system is re-energized for a minimum of five minutes. If the customer were to connect a backup generator, in the event to serve a critical load, he must open his main breaker or utilize a transfer switch prior to generator hook up, in order to ensure no back feed into the Company's distribution system. This is a critical safety requirement.

5.15 Voltage unbalance at the point of common coupling caused by the DG equipment under any condition shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100)

5.16 Make-Before-Break Transfer: Make-before-break transfer is only permitted between two live sources that are in, or close to, synchronism. A transfer switch designed for automatic make-before-break transition shall be equipped with logic to prevent a transfer if the specifications for either the DG owner or the Area EPS source fall outside of the synchronizing requirements recommended by the generator equipment manufacturer. Switch transfers made when the synchronizing requirements cannot be met shall be of the break-before-make type of transfer. The time that the DG owner's generation is permitted to operate in parallel with the Area EPS during a make-before-break transfer shall be no greater than 100 milliseconds (6 cycles).

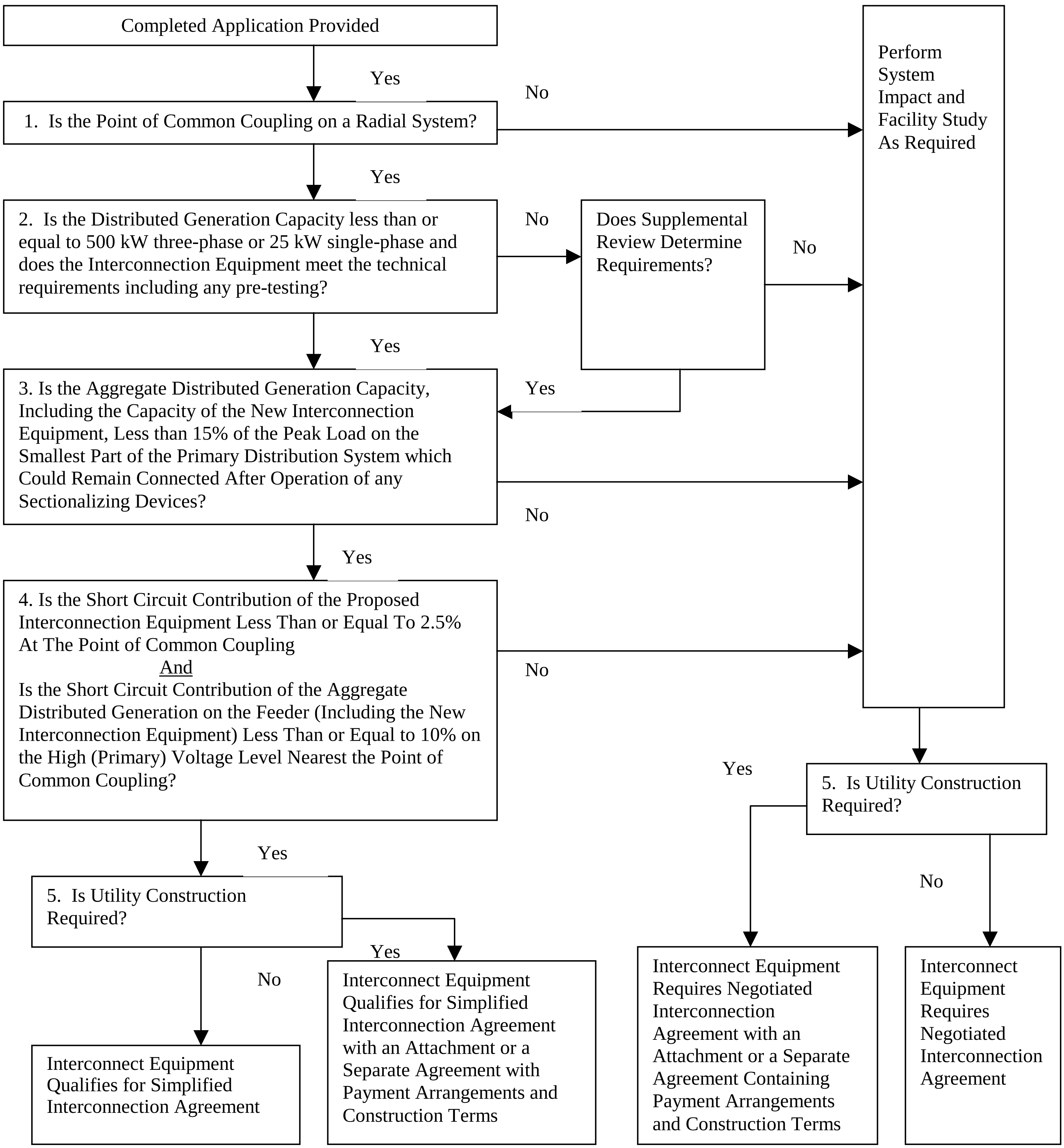
6.0 CUSTOMER OPERATING PROCEDURES

6.1 If high-voltage, low-voltage, or voltage flicker complaints arise from other customers due to the operation of customer DG, the customer may be required to disconnect his or her generation equipment from the Company's system until the problem has been resolved.

6.2 The operation of the DG equipment must not result in harmonic currents or voltages at the point of common coupling that will interfere with the Company's metering accuracy and/or proper operation of facilities and/or with the loads of other customers. Such adverse effects may include, but are not limited to heating of wiring and equipment, overvoltage, communication interference, etc.

6.3 The Customer must discontinue parallel operation when requested by the Company after reasonable prior notice except in an emergency, so that maintenance and/or repairs can be performed on the Company's facilities.

7.0 INTERCONNECTION REQUEST SCREENING PROCESS



Significance of Screens:

1. Is the Point of Common Coupling on a Radial System?

If the Point of Common Coupling is not on a radial distribution feeder, special considerations must be taken because of the design, protection and operational aspects of network distribution systems.

2. Is the Distributed Generation Capacity less than or equal to 500 kW three-phase or 25 kW single-phase and does the Interconnection Equipment meet the technical requirements including any pre-testing?

A supplemental review will be necessary if the Distributed Generation Capacity is larger than the 500 kW three-phase or 25 kW single-phase size limits or the Interconnection Equipment has not been tested as outlined to assure proper implementation of protective functions. Site commissioning tests may still be required in any event to insure that the system is connected properly and that the protective functions are working properly.

3. Is the Aggregate Distributed Generation Capacity, Including the Capacity of the New Interconnection Equipment, Less than 15% of the Peak Load on the Smallest Part of the Primary Distribution System which Could Remain Connected After Operation of any Sectionalizing Devices?

Low penetration of Distributed Generation will have a minimal impact on operation and load restoration. As the penetration increases the cumulative impact must be reviewed so a System Impact Study and possibly a Facilities Study will be necessary.

4. Is the Short Circuit Contribution of the Proposed Interconnection Equipment Less Than or Equal To 2.5% At The Point of Common Coupling
   And
   Is the Short Circuit Contribution of the Aggregate Distributed Generation on the Feeder (Including the New Interconnection Equipment) Less Than or Equal to 10% on the High (Primary) Voltage Level Nearest the Point of Common Coupling?

If the short circuit current contribution from the proposed Distributed Generation is small compared to the available fault current without the Distributed Generation connected, there will be no significant impact on the distribution system's short circuit duty, fault detection sensitivity and protective device coordination schemes.

5. Is Utility Construction Required?

Any required Utility construction would require agreement on the scope, the cost and the schedule for the work.

8.0 CUSTOMER DESIGN REQUIREMENTS

For an interconnection to be safe to Company employees/equipment and to other customers, the following conditions are required for customer-owned DG equipment.

In addition, the Company may, at its option, perform final review and inspection of the customer DG system installation prior to commissioning of its facility.

8.1 Customer DG facilities must meet all applicable national, state, and local construction, operation and maintenance related safety codes, such as National Electric Code (NEC), National Electric Safety Code (NESC), Occupational Safety and Health Administration (OSHA), etc.

8.2 Customer DG must provide the Company with a one-line diagram showing the configuration of proposed DG system. The DG owner is responsible for installing appropriate equipment and facilities so that the DG is compatible with the Company's distribution system.

8.3 The minimum Company's distribution system connection requirements for the DG are as follows:

8.3.1 Generator Frequency: The DG owner's facility will provide a balanced, symmetrical, three-phase interchange of electrical power with the Company's distribution system at a nominal frequency of 60 Hz ± 0.5Hz.

8.3.2 System Protection: The DG owner is responsible for providing adequate protection to Company's facilities for conditions arising from the operation of generation under all Company distribution system operating conditions. The owner is also responsible for providing adequate protection to their facility under any Company distribution system operating condition whether or not their DG is in operation. Conditions may include but are not limited to:

1. Loss of a single-phase of supply,
2. Distribution system faults,
3. Equipment failures,
4. Abnormal voltage or frequency,
5. Lightning and switching surges,
6. Excessive harmonic voltages,
7. Excessive negative sequence voltages,
8. Separation from supply,
9. Synchronizing generation,
10. Re-synchronizing the Owner's generation after electric restoration of the supply.

More complete relaying system requirements are identified later in this section.

8.3.3 Interrupting Device: All DG owners shall provide a three-phase circuit interrupting device with appropriate relaying systems to isolate the DG facilities from the Company supply for all faults, loss of Company supply, or abnormal operating conditions regardless of whether or not the owner's DG is in operation.

This device shall be capable of interrupting the maximum available fault current at that location. The three-phase device shall interrupt all three phases simultaneously. The tripping control of the circuit interrupting device shall be powered independently of the utility AC source in order to permit operation upon loss of the Company's distribution system connection.

The specific reclosing times for the DG owner's circuit interrupting device will be provided by the Company. It is the DG owner's responsibility to design and maintain their interrupting device(s) to properly isolate generation upon loss of the Company's connection until the appropriate Company facilities are returned to service.

8.3.4 System Grounding: The DG system should be grounded in accordance with applicable codes. A ground fault sensing scheme will be required by the DG customer when he uses a wye-delta connected transformer as part of the DG connection to the Company's system. This ground fault scheme will protect the customer's equipment from system ground faults that may occur in his system, or in the Company's system to which the customer is connected. Information relating to grounding of photovoltaic (PV) systems as required by the NEC can be found in "Photovoltaic Power Systems and the National Electrical Code: Suggested Practices, SAND96-2797, Sandia National Laboratories, 1996.

8.3.5 Voice Communication Circuit: The DG owner may be required to establish a dedicated voice communication circuit to the Company's system control center to permit coordination of the synchronization and operation of the generation, depending on the DG's capacity (kW).

8.3.6 Disconnecting Devices: A three-phase air break switch or a three-pole single-throw disconnect switch shall be installed on each distribution line supply entrance to the Owner's facility to be accessible at all times. The disconnecting device shall be mechanically lockable in the open position with a Company lock in order to provide for a visible electric isolation of the Owner's facility and shall be identified with a Company designated equipment number. The disconnect switch is required to isolate the DG for the purposes of safety during maintenance and during emergency conditions. The device must be clearly labeled as a DG interrupting device.

8.3.7 Disturbance Monitoring: The DG owner's system must have disturbance monitoring equipment on larger machines.

8.3.8 Transient Stability Performance: Transient stability performance of the DG is the responsibility of the DG owner. Transient stability performance should be in accordance with the Company's Transient Stability Criteria. The Company may, at its discretion, elect to perform the necessary studies to evaluate transient stability performance. The cost of these studies will be borne by the DG owner as part of the System Impact Study.

8.4 Excitation Control: In addition to the normal excitation system and automatic voltage regulation equipment, the following controls are also required for each synchronous generator.

8.4.1 Overcurrent Limiter: The excitation system is to be provided with a current limiting device which will supercede or act in conjunction with the Automatic Voltage Regulator to automatically reduce excitation so that generator field current is maintained at the allowable limit in the event of sustained under-voltages on the distribution system. This device must not prevent the exciter from going to and remaining at the positive ceiling for 0.1 seconds following the inception of a fault on the power system.

8.4.2 Underexcitation Limiter: A limiter to prevent instability resulting from generator underexcitation is required.

8.4.3 Power System Stabilizer: Company studies may identify the need for the use of power system stabilizers, depending on the plant size, excitation system type and settings, facility location, area distribution system configuration and other factors. This will be determined on a case-by-case basis.

8.5 Speed Governing: All synchronous generators shall be equipped with speed governing capability. This governing capability shall be unhindered in its operation consistent with overall economic operation of the DG facility. Overspeed protection in the event of load rejection is the responsibility of the DG owner.

8.6 Dynamic Performance Data: Dynamic performance data shall be made available to the Company as part of the facility specifications and plans for evaluation by the Company. This data is required to evaluate the system dynamic performance of the DG facility which includes but is not limited to transient stability. For synchronous generators, the required dynamic performance data are listed in Appendix B. For other types of generators, appropriate modeling data shall be made available to represent the generator in commonly used stability study software.

8.7 Automatic Generation Control (AGC): Depending upon various control area factors applicable to tie line and frequency regulation, provision for dispatch control of the DG facility by the Company's system control center AGC system may be required. This will be considered on a case-by-case basis and any provision for control by AGC should be included in a Connection Agreement between the DG owner and the Company.

8.8 Black Start Capability: Depending upon the geographic location and other considerations applicable to system restoration in the event of a blackout, the provision of blackstart[1] capability may be required or desirable. The Connection Agreement is to address this matter. Responsibilities of the DG owner will be addressed in the Connection Agreement.

8.9 Unbalanced Electric Conditions

8.9.1 Voltage Balance: All three-phase generation shall produce balanced 60 Hz voltages. Voltage unbalance attributable to the DG combined generation and load shall not exceed 2.5% measured at the point-of-service. Voltage unbalance is defined as the maximum phase deviation from average as specified in ANSI C84.1, "American National Standard for Electric Power Systems and Equipment – Voltage Ratings, 60 Hertz."

8.9.2 Current Balance: Phase current unbalance attributable to the DG owner combined generation and load shall not exceed that which would exist with balanced equipment in service, measured at the point-of-common coupling. Situations where high unbalance in voltage and/or current originate from the distribution system are to be addressed in the Connection Agreement.

8.10 Harmonics and Flicker: The DG owner shall take responsibility for limiting harmonic voltage and current distortion and/or voltage flicker[6] caused by their DG equipment. Limits for harmonic distortion (including inductive telephone influence factors) are consistent with those published in the latest issues of ANSI/IEEE 519, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems." A specific example of harmonics and flicker criteria is given in Appendix C. Company criteria requires that flicker occurring at the point of compliance shall remain below the Border Line of Visibility curve on the IEEE/GE curve for fluctuations less than 1 per second or greater than 10 per second. However, in the range of 1 to 10 fluctuations per second, voltage flicker shall remain below 0.4% (see Appendix C, Exhibit 1). Depending upon the nature of the generation and its location, the Company may require the installation of a monitoring system to permit ongoing assessment of compliance with these criteria. The monitoring system, if required, will be

[1] A blackstart capable generation facility is one that can be started without the aid of off-site power supplied by the distribution system.

[6] Flicker is an objectionable, low frequency, voltage fluctuation which can be observed through changes in intensity or color of illumination.

installed at the DG owner's expense. Situations where high harmonic voltages and/or currents originate from the distribution system are to be addressed in the Connection Agreement.

8.11 Abnormal System Conditions: Customer DG must be equipped with adequate protection to automatically trip[4] the unit off line during abnormal[5] system conditions, according to the following guidelines:

8.11.1 Induction Generator or Line-Commutated Inverter Interface

(a) Undervoltage or overvoltage, typically minus 10% with a base voltage of 120 volts, or plus 10%, respectively, with a base voltage of 120 volts, or equivalent service delivery voltage.

(b) For three-phase generation, loss of balanced three-phase voltage or a single-phasing condition[6]. Voltage unbalance under any condition shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100)

8.11.2 Synchronous Generator, Alternator or Self-Commutated Inverter Interface

(a) Undervoltage or overvoltage, typically minus 10% with a base voltage of 120 volts, or plus 10%, respectively, with a base voltage of 120 volts, or equivalent service delivery voltage.

(b) Underfrequency or overfrequency, typically minus or plus 0.5 Hz at a 60 Hertz base frequency, respectively.

(c) For three-phase generation loss of balanced three-phase voltage or a single-phasing condition. Voltage unbalance under any condition shall not exceed 3% (calculated as in section 5.11.1(b).

(d) When the Company's frequency is outside the range of nominal frequency, the DG shall be constructed to cease to energize the Company's Distribution System within 15 Cycles. By agreement of both the DG operator and the Company's Distribution System operator, different settings maybe used for the under frequency and over frequency trip levels or time delays.

8.12 Additional protection: Customer DG, depending on the size, must include the following additional protection to avoid possible damage to the customer's DG

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[4] To trip is to open the appropriate breaker to de-energize the voltage source.

[5] Abnormal system conditions include faults due to adverse weather conditions including but not limited to floods, lighting, vandalism, and other acts that are not under the control of the LDC. This may also result from improper design and operation of customer facilities resulting from non-compliance with accepted industry practices.

[6] A Single-phasing condition occurs when one phase of the three-phase supply line is disconnected. The generator would concentrate its output on the isolated phase, trying to maintain voltage on the faulted phase.

equipment and the Company's system during normal, as well as abnormal system conditions.

8.12.1 Ground detector to detect a circuit ground on the Company's Distribution System;

8.12.2 Individual phase overcurrent relays with voltage restraint;

8.12.3 Directional overcurrent relays to detect the directional flow of current in excess of a desired limit;

8.12.4 Synchronizing controls to insure a safe interconnection with the Company's distribution system. The DG must be capable of interconnection with minimum voltage and current disturbances. Synchronous generator installations, as well as other types of installations, must meet the following: slip frequency less than 0.1 Hz, voltage deviation less than $\pm$ 10%, phase angle deviation less than $\pm$ 10 degrees, breaker closure time compensation (not needed for automatic synchronizer that can control machine speed).

8.12.5 Transfer trip receiver to provide tripping logic to the DG for isolation of the DG upon opening of the Company's distribution circuits. (Depending upon generator size, a transfer trip scheme on the transmission or distribution side of the station may be required, only in the event that the customer does not have non-islanding protection requirements.)

8.12.6 Directional power relays to detect, under all system fault conditions, a loss of the Company's primary source;

8.12.7 Adequate protection for the customer's facilities for high-speed reclosing operations on the Company's subtransmission/transmission circuits, must be provided by the customer. The customer must supply relaying and detection to make sure that its machine trips off before the Company's Distribution System performs a reclose operation. The Company Distribution System's reclosing scheme will not change to accommodate a DG owner's protection scheme that may undermine the distribution system's integrity.

8.12.8 The Company, at the expense of the DG owner, will install a potential sensor indicator on the line side of the recloser in order that the Company can make sure that the DG is de-energized before the Company allows the breaker to reclose. This installation is necessary to protect the DG Owner's employees and equipment, and the Company's employees and equipment. The customer has the responsibility of supplying the relaying and detection to make sure that his machine trips off line before the Company performs a reclose operation.

8.12.9 Islanding: When the DG is capable of supplying energy to the Company's Distribution System for 60 or more cycles (one second or more) during a fault, or when the distribution circuit, interconnected with the DG is de-energized from the Company's source, the Company will require additional protection equipment to isolate the DG from the Company's system, in order to avoid unintentional islanding[7] of the DG. .

In some cases, intentional islanding may be permitted when both their DG operator and the Company desire such conditions.

8.12.9.1 Intentional Islanding: Intentional islands for distributed generators will only be established by mutual agreement and contractual arrangement that includes all parties – Company (grid operator), distributed energy resource(s), and load customer(s).

8.12.9.2 An islanding study must be performed by the Company for each intentional island including, but not limited to, the following:

(1) A planning study will verify that the entire island will operate within required voltage and frequency for each island configuration. It will also determine whether there is a requirement for upgrading or replacing Company equipment or conductors in order to accommodate the anticipated load flows in the islanded condition.

(2) Stability studies will check generator-generator and generator-load interactions and verify that the island will be stable.

(3) Fault studies will ensure the protective relaying functions located at the generator will be able to properly detect faults at all parts of the island, and under all possible switching configurations and generator combinations that are not protected by customer owned protection schemes. These fault studies will check for relay de-sensitization and will determine whether protective relay settings on utility and/or customer owned protection schemes will require settings changes, scheme/equipment revisions, or wholesale replacement. These fault studies will determine what new protection in addition to that already in place will be required such as, but not limited to, additional relaying equipment at designated distribution system tie points to allow islanding upon grid trouble and to allow paralleling upon restoration of the grid.

8.12.9.3 The DG must have load following capability and sufficient voltage regulation capability such that the voltage and frequency of the island is maintained within the limits imposed on the Company.

[7] Unintentional Island—an unplanned condition where one or more DGs and a portion of the electric utility grid remain energized through the point of interconnection.

8.12.9.4 The DG cannot force customers who are physically a part of the island to purchase power from them. The DG must supply power to non-participating customers free of charge.

8.12.10 The protective relays required by the Company and any auxiliary tripping relays associated with those relays shall be utility-grade devices.

8.12.11 Utility-grade relays are defined as follows:

(1) Meet ANSI/IEEE Standards C37.90, C37.90.1 and C37.90.2.
(2) Have relay test facilities to allow testing without unwiring or disassembling the relay,
(3) Have appropriate test plugs/switches for testing the operation of the relay,
(4) Have targets to indicate relay operation.

8.13 Power factor must be maintained between 90% lagging and 90% leading unless otherwise agreed to by parties. If the customer DG imposes an unusual reactive burden on the Company's system such that the customer's net load or net generation power factor exceeds 0.90 lead or lag, the customer may be required to install reactive corrective equipment. In the case of an induction generator application, VAR support may be required. Where VAR support is contemplated, the Company should be consulted.

8.14 Customer equipment must have adequate fault interruption and withstand capacity, and adequate continuous current and voltage rating to operate properly[8] with the Company's present and planned future system.

8.15 The DG owner can facilitate the Company approval process for the DG interconnection by assuring that the DG interconnection equipment meets Company pre-certification requirements. Conformance tests shall be performed by a manufacturer to confirm that the interconnection system design meets requirements. Factory tests shall be performed by a manufacturer in the factory before equipment is shipped. These tests should cover the testing of DC Current Injection, overvoltage protection, undervoltage protection, overfrequency protection, underfrequency protection, current unbalance, surge withstand capability, fast transient testing, islanding detection, dielectric testing, etc. This list is not all-inclusive.

8.16 When inverter systems are intended to be used as the DG, they should be pre-tested, approved and listed by Underwriter's Laboratories or similar independent testing laboratories for harmonics and other specification issues such as frequency operating range and current-distortion levels.

8.17 When synchronous or induction generators are used for the DG, several types of data will be required by the Company such as reactance data, field time constant data, etc. The customer must provide DG test data to the Company.

[8] Properly, in this context, means within the acceptable utility or applicable industry established parameters.

8.18 Customer generation must operate and maintain voltage within normal Company limits of ± 5% of 120 volts or equivalent service delivery voltage, at the interconnection point.

8.19 A ground fault sensing scheme may be required by the customer, depending on the type of transformer connection of the customer's DG to the Company's system. This ground fault scheme will protect the customer's equipment from system ground faults that may occur in his system, or in the Company's system to which the customer is connected.

8.20 The customer must notify the Company in the event of a change in the design, size, or technology for the DG before final plans are implemented.

8.21 In large DG applications where telemetry is required, the following data, at a minimum, is required to be received by the Company: MW out, MWHs out, MVARs (lead and lag) and DG breaker position (open or closed).

9.0 CUSTOMER OPERATING PROCEDURES

9.1 Voltage Disturbances: The DG facility must be capable of continuous non-interrupted operation within a steady-state voltage range during system normal conditions. This range varies based on the following table:

Response to Abnormal Voltages

Voltage		Maximum Trip Time (T)
V<60	(V<50%)	10 cycles
60≤V<106	(50%≤V<88%)	120 cycles
106≤V≤132	(88%≤V≤110%)	Normal Operation
132<V<165	(110%<V<137%)	120 cycles
165≤V	(137%≤V)	6 cycles

(T) "Trip Time" refers to the time between the abnormal condition being applied and the inverter, or interconnection device, ceasing to energy the utility line. The inverter, or interconnection device, will actually remain connected to the utility to allow sensing of utility electrical conditions for use by the "reconnect" feature.

9.2 The DG facility must be capable of continuous, uninterrupted operation in the frequency range of 59.5 to 60.5 Hz. Limited time, non-interrupted operation is also expected outside this frequency range in accordance with the generator manufacturer's recommendation.

9.3 If high-voltage, low-voltage, or voltage flicker complaints arise from other customers due to the operation of customer DG, the customer may be required to disconnect its generation equipment from the Company's system until the problem has been resolved.

9.4 Customer DG must not produce harmonic currents or voltages that will interfere with the Company's metering accuracy and/or proper operation of facilities and/or with other customer loads. Such adverse effects may include, but are not limited to heating of wiring and equipment, overvoltage, communication interference, etc.

9.4.1 When a primary line fault occurs on the Company's distribution circuit, the DG customer must trip off-line in 60 cycles (one second) or less, thus clearing and not sustaining a fault on the Company's system.

9.5 The customer should not reconnect DG to the Company's system after a trip from a system protection device, until the Company's system is energized for a minimum of five minutes. If the customer need to connect a backup generator, in the event to serve to a critical load, he must open his main breaker or transfer switch, prior to generator hook up, in order to ensure no back feed into the Company's distribution system. This is a critical safety requirement.

9.6 The customer may be required to discontinue parallel operation when requested by the Company, so that maintenance and/or repairs can be performed on the Company's facilities.

9.7 The customer will be responsible for damage caused to other customers and/or to the Company, due to a malfunction, improper design, misoperation or human error of the customer's DG or controls.

9.8 The customer must notify the Company in the event that the DG is removed from service on a permanent basis.

9.9 Net Demonstrated Real and Reactive Capabilities: Individual synchronous generators in the DG facility must make available the full steady-state over-and under-excited reactive capability given by the manufacturer's generator capability curve at any dispatch level. Tests that demonstrate this capability must be conducted and documented on a regular basis. Such documentation should be provided to the Company. The Company reserves the right to witness these tests.

9.10 Make-Before-Break Transfer: Make-before-break transfer is only permitted between two live sources which are in, or close to, synchronism. A transfer switch designed for automatic make-before-break transition shall be equipped with logic to prevent a transfer if the specifications for either the DG owner or the Company's distribution system source fall outside of the synchronizing requirements recommended by the generator equipment manufacturer. Switch transfers made when the synchronizing requirements cannot be met shall be of the break-before-make type of transfer. The time that the DG owner's generation is permitted to operate in parallel with the Company's distribution system during a make-before-break transfer shall be no greater than 100 milliseconds(6 cycles)

9.11 Operating Restrictions: Situations necessitating generation curtailments or forced outages as the result of unavailability of distribution facilities owned and/or operated by the Company are to be addressed in a Connection Agreement with the DG owner.

APPENDIX A

Generation Dynamic Performance Data

Customer Name ______________________________________ Date ___/___/___ Page 1/2

GENERATOR DATA

UNIT RATINGS

kVA	________	________ °F	Voltage	________
Power Factor		________	H_2 psig	________
Speed (RPM)		________	Connection (e.g. Wye)	________
Short Circuit Ratio		________	Frequency, Hertz	________
Stator Amperes at Rated kVA		________	Field Volts	________
Max Turbine MW	________	________ °F		

REACTANCE DATA (PER UNIT-RATED KVA)	**DIRECT AXIS**		**QUADRATURE AXIS**	
Synchronous – saturated	Xdv	________	Xqv	________
Synchronous – unsaturated	Xdi	________	Xqi	________
Transient – saturated	X'dv	________	X'qv	________
Transient – unsaturated	X'di	________	X'qi	________
Subtransient – saturated	X"dv	________	X"qv	________
Subtransient – unsaturated	X"di	________	X"qi	________
Negative Sequence – saturated	X2v	________		
Negative Sequence – unsaturated	X2i	________		
Zero Sequence – saturated	X0v	________		
Zero Sequence – unsaturated	X0I	________		
Leakage Reactance	Xlm	________		

FIELD TIME CONSTANT DATA (SEC)

Open Circuit	T'do	________	T'qo	________
Three-Phase Short Circuit Transient	T'd3	________	T'q	________
Line to Line Short Circuit Transient	T'd2	________		
Line to Neutral Short Circuit Transient	T'd1	________		
Short Circuit Subtransient	T"d	________	T"q	________
Open Circuit Subtransient	T"do	________	T"qo	________

ARMATURE TIME CONSTANT DATA (SEC)

Three-Phase Short Circuit	Ta3	________
Line-to-Line Short Circuit	Ta2	________
Line-to-Neutral Short Circuit	Ta1	________

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive	R1	________		
Negative	R2	________		
Zero	R0	________		
Rotor Short Time Thermal Capacity $I2^2t$	=	___________		
Field Current at Rated kVA, Armature Voltage and PF	=	___________	amps	
Field Current at Rated kVA and Armature Voltage, 0 PF	=	___________	amps	
Three-phase Armature Winding Capacitance	=	___________	microfarad	
Field Winding Resistance	=	___________	ohms	_______ °C
Armature Winding Resistance (Per Phase)	=	___________	ohms	_______ °C

Customer Name ______________________________________ Date ___/___/___ Page 2/2

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = ____________________ kW sec/kVA
Moment-of-Inertia, WR^2 = ____________________ lb. ft.^{2}

CURVES

Saturation, Vee, Reactive, Capacity Temperature Correction

GENERATOR STEP-UP TRANSFORMER DATA

RATINGS

Capacity Self-cooled/maximum nameplate ______________/______________ kVA

Voltage Ratio Generator side/System side ______________/______________ kV

Winding Connections Low V/High V (Delta or Wye) ______________/______________

Fixed Taps Available ____

Present Tap Setting ____

IMPEDANCE

Positive Z1 (on self-cooled kVA rating) ____________________________ % ______ X/R

Zero Z0 (on self-cooled kVA rating) ____________________________ % ______ X/R

EXCITATION SYSTEM

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

APPENDIX B

Voltage Flicker Criteria and Harmonic Distortion Criteria

Voltage Flicker Criteria and Harmonic Distortion Criteria

I. POINT OF COMPLIANCE – The point of common coupling will be the point where compliance with the voltage flicker and harmonic distortion requirements are evaluated.

II. VOLTAGE FLICKER CRITERIA – The Company requires that the voltage flicker occurring at the point of compliance shall remain below the Border Line of Visibility curve on the IEEE/GE curve for fluctuations less than 1 per second or greater than 10 per second (see Exhibit 1). In the range of 1 to 10 fluctuations per second, the voltage flicker shall remain below 0.4%.

The Customer agrees that under no circumstances will it permit the voltage flicker to exceed the Company criteria, whether or not complaints are received or service/operational problems are experienced on the Company subtransmission or distribution system. Should complaints be received by the Company or other operating problems arise, or should the Customer flicker exceed the borderline of visibility curve, the Customer agrees to take immediate action to reduce its flicker to a level at which flicker complaints and service/operational problems are eliminated.

Corrective measures could include, but are not limited to, modifying production methods/ materials or installing, at the Customer's expense, voltage flicker mitigation equipment such as a static var compensator. The Company will work collaboratively with the Customer to assess problems, identify solutions and implement mutually agreed to corrective measures.

If the Customer fails to take corrective action after notice by the Company, the Company shall have such rights as currently provided for under its tariffs, which may include discontinuing service, until such time as the problem is corrected.

III. HARMONIC DISTORTION CRITERIA - The Company also requires that the Customer's operation be in compliance with the following Harmonic Distortion Guidelines. These requirements are based on IEEE Standard 519, "IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems".

HARMONIC DISTORTION REQUIREMENTS

At the point of common coupling the Individual Harmonic Voltage Distortion shall not exceed 3.0% and the Total Voltage Distortion* shall not exceed 5.0%.

HARMONIC CURRENT DISTORTION LIMITS
Maximum Harmonic Current Distortion In % Of Base Quantity

I_{SC}/I_L	<11	11 [h<17	17[h<23	23[h<35	35[h	TDD*
<20	4.0	2.0	1.5	0.5	0.3	5.0
20-50	7.0	3.5	2.5	1.0	0.5	8.0
50-100	10.0	4.5	4.0	1.5	0.7	12.0
100-1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

Where I_{SC} = Maximum short circuit at point of common coupling and I_L = Load current at the time of the maximum metered amount

Even harmonics are limited to 25% of the odd harmonic limits above.

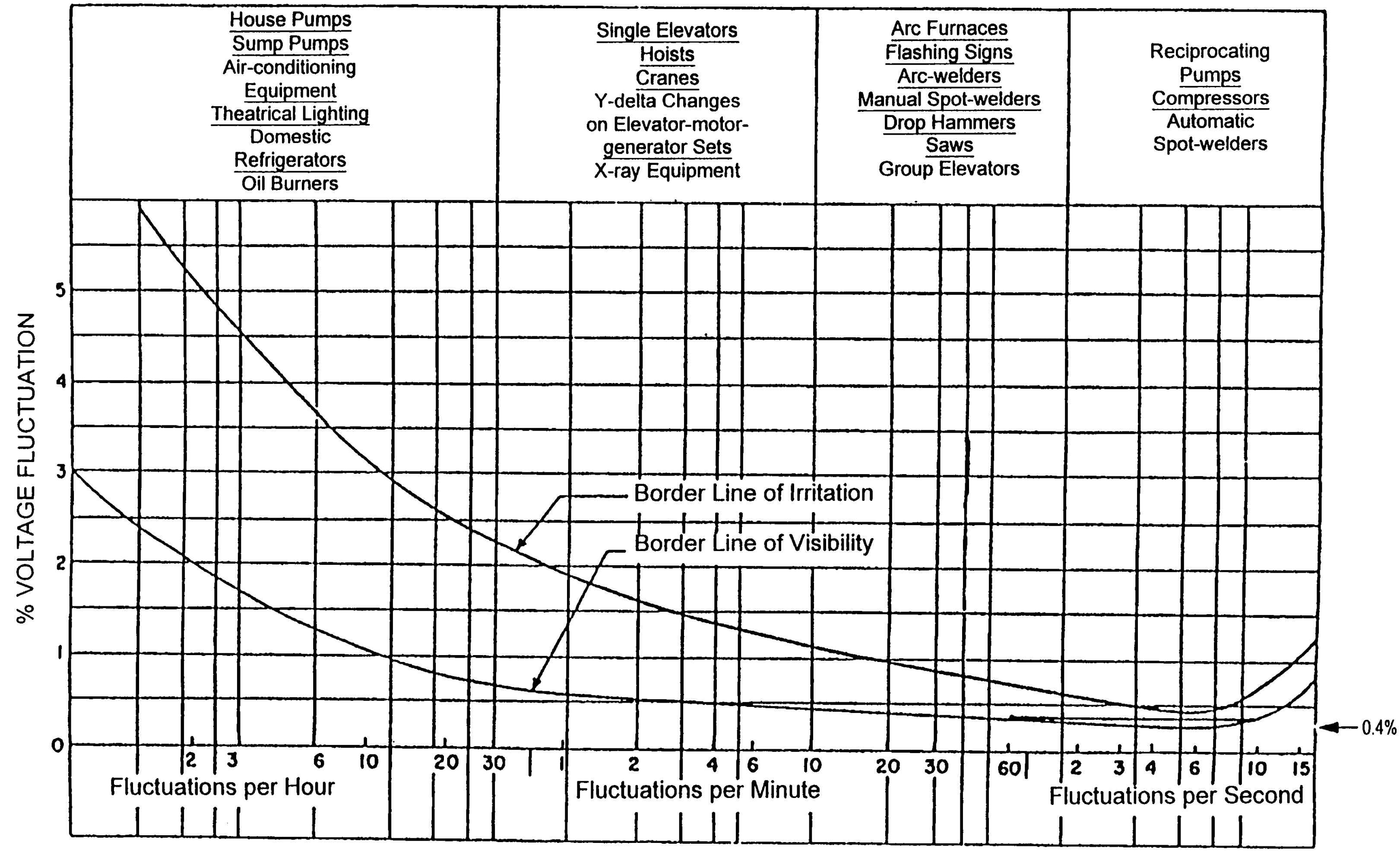
* See Exhibits 3 and 4 attached.

The Customer agrees that the operation of motors, appliances, devices or apparatus served by its system and resulting in harmonic distortions in excess of the Company's Requirements will be the Customer's responsibility to take immediate action, at the Customer's expense, to comply with the Company's Harmonic Distortion Requirements.

The Company will work collaboratively with the Customer to assess problems, identify solutions and implement mutually agreed to corrective measures.

If the Customer fails to take corrective action after notice by the Company, the Company shall have such rights as currently provided for under its tariffs, which may include discontinuing service, until such time as the problem is corrected.

Exhibit 1



Composite curve of voltage flicker studies by General Electric Company, *General Electric Review*, August 1925; Kansas City Power & Light Company, *Electrical World*, May 19, 1934; T&D Committee, EEI, October 24, 1934, Chicago; Detroit Edison Company; West Pennsylvania Power Company; Public Service Company of Northern Illinois.

Relations of Voltage Fluctuations to Frequency of Their Occurrence (Incandescent Lamps)

EXHIBIT 3

Definitions

o **Harmonic Voltage Distortion** is to be normalized to the nominal system voltage and calculated using Equation 1.

TOTAL VOLTAGE HARMONIC DISTORTION (THD_V) in percent:

$$THD_v = \frac{\sqrt{\sum_{n=2}^{\infty} V_n^2}}{V_s} \times 100\% \qquad (Eq.1)$$

Where:

V_n = Magnitude of Individual Harmonics (RMS)
V_s = Nominal System Voltage (RMS)
n = Number of Harmonic Order

o **Harmonic Current Distortion** is to be normalized to the customer's load current at the time of the maximum metered demand which occurred over the preceding twelve months for existing customers and the customer's anticipated peak demand for new customers. For existing customers who are increasing their load, the projected demand should be used. The harmonic current demand distortion (TDD) should be calculated using Equation 2.

TOTAL CURRENT DEMAND DISTORTION (TDD) in percent:

$$TDD = \frac{\sqrt{\sum_{n=2}^{\infty} I_n^2}}{I_L} \times 100\% \qquad (Eq.2)$$

Where:

I_n = magnitude of Individual Harmonic (RMS)
I_L = Load Current at the Time of the Maximum Metered Demand
n = Harmonic Order

o **PCC - Point of Common Coupling.** The location where the customer accepts delivery of electrical energy from the utility.

Field Measurements

To gauge the acceptability of field measured harmonic distortion, a statistical evaluation of the data is to be performed. Measurements should be taken at five minute intervals or less over a minimum of 24 hours. For the measured data to be considered acceptable, two criteria must be met: 1) 95% of the measured data must fall below the limits stated; 2) no measured data shall exceed the limits specified by more than 50% of the absolute upper limit value.

Communication Interference Limits (I*T)

EXHIBIT 4

As stated in IEEE Standard 519, it is difficult to place specific limits on the telephone influence which the harmonic components of current and voltage can inflict. Hence, IEEE Standard 519 outlines a range of values where problems could occur (refer to the table below). The actual interference to voice communication systems in proximity to the power system is dependent upon a number of factors not under the control of the utility or customer. These factors will vary from location to location and from time to time as the state-of-the-art of inductive coordination progresses.

IEEE Standard 519 - Balanced I*T Guidelines		
Category	Description	I*T
I	Levels most unlikely to cause interference	<10,000
II	Levels that might cause interference	10,000 to 25,000
III	Levels that probably will cause interference	> 50,000

The limit applicable is the upper bound limit of the I*T levels that might cause interference on telephone systems. Thus, the customer induced harmonics shall not result in an I*T product to exceed 25,000 weighted amperes per phase, applicable to both the transmission and distribution systems. Residual I*T should also be minimized. Residual I*T is I_G*T, where I_G is the earth return current and is defined as the difference between the phasor sum of phase currents and neutral current. The I*T calculation is to be performed using Equation 3. The weighting of harmonic currents should conform to the 1960 TIF curve shown below.

$$I*T = I*TIF = \sqrt{\sum_{n=1}^{K} (I_n * W_n)^2} \text{ weighted amperes} \qquad (Eq.3)$$

Where:

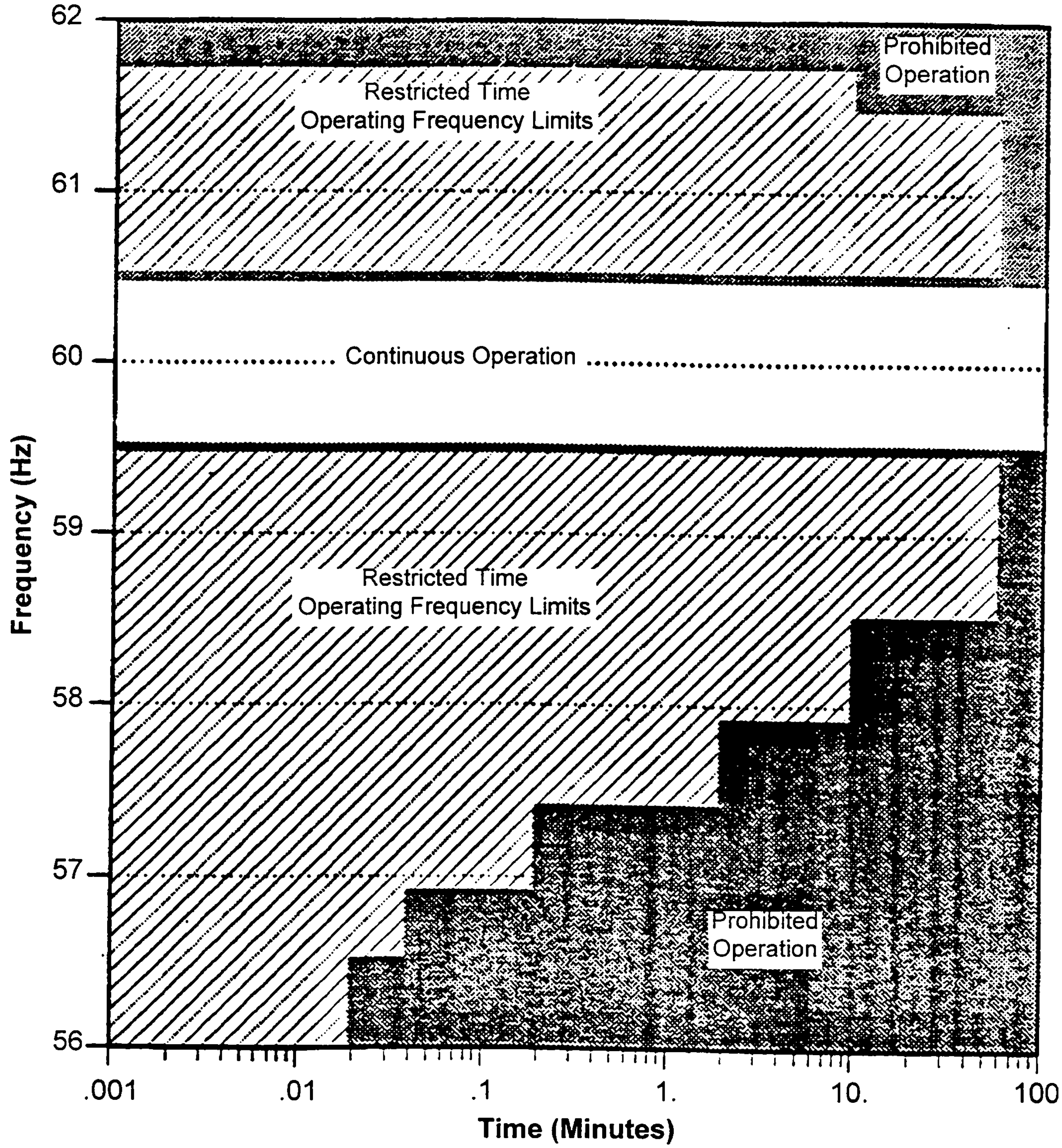
I = Current of individual harmonics, amperes, RMS
T = Telephone Influence Factor (TIF)
W_n = Single frequency TIF weighting at frequency n (refer to table and chart below)
K ≤ 42, Maximum harmonic order

FREQ	TIF (W)	FREQ	TIF (W)	FREQ	TIF (W)	FREQ	TIF (W)
60	0.5	1020	5100	1860	7820	3000	9670
180	30	1080	5400	1980	8330	3180	8740
300	225	1140	5630	2100	8830	3300	8090
360	400	1260	6050	2160	9080	3540	6730
420	650	1380	6370	2220	9330	3660	6130
540	1320	1440	6650	2340	9840	3900	4400
660	2260	1500	6680	2460	10340	4020	3700
720	2760	1620	6970	2580	10600	4260	2750
780	3360	1740	7320	2820	10210	4380	2190
900	4350	1800	7570	2940	9820	5000	840
1000	5000						

APPENDIX C

Generation Abnormal Frequency Operating Allowance

Generation Abnormal Frequency Operating Allowance



APPENDIX D

Notification of Intent to Install and Operate DG
Interconnected
With the Company's Distribution System

PURPOSE: The information to be provided in this Notification of Intent to Install and Operate a Distributed Energy Resource (DG) is necessary to evaluate and successfully integrate the DG facility within the Company's distribution system and to provide for compatible operation of the integrated facilities. Failure to comply with the Company's Tariffs and Regulations filed with the Federal and State agencies having jurisdiction in the Company's operating area may result in discontinuation of service or refusal to furnish service to the DG.

FILING: Any DG owner who plans to install generation that will be connected to the interconnected elements of an electric service supplied from the Company's distribution system is to complete this document and submit it to a Company Customer Service representative. Any subsequent change in the information supplied by the DG owner on this document is to be communicated to the Company Customer Service representative by the DG owner as soon as available.

NON-REFUNDABLE FEE/OTHER COSTS: The DG owner is required to pay a nonrefundable application fee as described in schedules filed with the Michigan Public Service Commission. The DG owner shall reimburse the Company for all costs incurred by the Company for facilities and services required to review, evaluate and provide for operation of the **Owner's** generation, including, but not limited to, the evaluation of information provided in this document. Following the project completion, customer-written notification of the project termination, or other interval as determined by the Company, an accounting of the charges due the Company less the non-refundable fee will be submitted to the DG owner.

1.0 OWNER INFORMATION

Entity/Requester/Company Name: ____
Facility Owner's Name: ____
Mailing Address: ____
City: _______________ County: _______________ State: ______ Zip Code: ______________

2.0 PROJECT DESIGN/ENGINEERING INFORMATION

Company: ____
Mailing Address: ____
City: _______________ County: _______________ State: ______ Zip Code: ______________
Contact Representative: _____________________________________ Phone No. ______________

3.0 FACILITY INFORMATION

3.1 Does the **Owner's** proposed generator facility quality as a PURPA facility?
______ Yes ______ No
If yes, attach a copy of the required information the **Owner** has filed or proposes to file with the Federal Energy Regulatory Commission.

3.2 Does the **Owner** propose to export power to the Company's distribution system?
______ Yes ______ No
If yes, indicate the proposed contract type to be made with Company:
(a) Proposed Contract Capacity in kW to Company ________________
(b) Proposed Yearly kWh Sales to Company ______________________
(c) Indicate Sales Schedule _______ kW On-Peak _______ kW Off-Peak
_______ kWh On-Peak _______ kWh Off-Peak

3.3 How many generating units does the owner propose to operate? ______
Specify the proposed operating date for each unit: ____________ ____________
____________ ____________ ____________ ____________ ____________

4.0 ESTIMATED OPERATIONAL INFORMATION

This information will be used to properly determine the capacity interfacing requirements for the **Owner's** proposed generation facility, and establish maintenance, supplementary, and backup power requirements.

4.1 Generator Operating Hours/Year: ____________________

4.2 The Generation System will operate in the following mode:
- Base Load On-Peak Only
- Base Load 24 Hours a Day
- Peak Shaving
- Emergency/Maintenance Only

4.3 Energy Generated MWH/Year: ______________________

4.4 Min. and Max. Anticipated Facility Load with Generator not Operating:
Minimum - _____ kW _____ kVA Maximum - _____ kW _____ kVA

4.5 Min. and Max. Anticipated Facility Load with Generator Operating:
Minimum - _____ kW _____ kVA Maximum - _____ kW _____ kVA

4.6 Specify the contract capacity desired:
_____ kW _____ kVA

NOTE: Specified Supplementary Capacity plus Specified Backup Capacity must equal the Specified Contract Capacity.

5.0 GENERATION EQUIPMENT INFORMATION

The following data is to be provided for each generating unit. Additional copies may be submitted for multiple units.

5.1 Energy Resource Data

Manufacturer (if available): ____

Model: ______________________

Type: Synchronous Induction Inverter

Frequency (Hz): ________________

Rated Output: ___________________ kW ___________________ kVA

Rated Power Factor (%): __________ Rated Voltage (Volts): __________

Rated Amperes: __________

5.2 Prime Mover

Manufacturer (if available): ____

Model: ______________________

Rated Horsepower: ________________ Maximum Horsepower: ________________

Type:
- ❑ Steam Turbine
- ❑ Fuel cell
- ❑ Combustion Turbine
- ❑ Induction
- ❑ Synchronous
- ❑ Wind
- ❑ Battery
- ❑ Other (Specify): ____________________________________

ENERGY Source: Coal Oil Gas
- ❑ Off-peak utility
- Renewable (Specify) ______________________
- Other (Specify) __________________________

6.0 <u>ATTACHMENTS OWNER TO PROVIDE WITH THIS NIOG</u>

6.1 A summary, signed by the **Owner** management, that provides a general description of the intended manner or operation for the DG facility.

6.2 Three copies of drawings and specifications prepared and approved by a registered professional engineer adequately detailing the facility location and proposed location of the **Owner's** generation facilities with respect to the **Owner's** desired point of electric service and the appropriate disconnecting devices.

6.3 Three copies of a comprehensive single-line diagram prepared and approved by a registered professional engineer. This information must comprehensively show the **Owner's** intended configuration for operation including switching devices, transformers, generation facility, protective devices, metering devices, capacitors, proposed conductor sizes, etc.

7.0 <u>OWNER AUTHORIZATION</u>: I, the undersigned and authorized representative of the above DG facility, acknowledge that the aforementioned information is to be used for a review process performed by the Company who will subsequently provide appropriate engineering and operational comments and/or concerns that must be addressed and jointly resolved with the Company.
Owner permission to operate generation in parallel with the Company will only be granted after specified Company requirements and contractual commitments are met. I also acknowledge receipt from a Company Customer Service Representative of a document titled "Requirements for Interconnection and Parallel Operation of Distributed Generation."

Authorized Signature: ________________________________ Date: ____________________

Name (Print): ____________________________________ Title: ________________________