Massachusetts Technology Collaborative Network Protector Enabled Generation (NPEG) Performance Specification

MASSACHUSETTS TECHNOLOGY COLLABORATIVE

RENEWABLE ENERGY TRUST

Version 2.2

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Preface

Network Protector Enabled Generation (NPEG) is the term that has been coined to represent a body of research conducted under the auspices of the Massachusetts DG Collaborative and funded by the Massachusetts Technology Collaborative (MTC), a Massachusetts economic development agency. The NPEG concept describes a proposed solution to the challenge of safely interconnecting distributed energy resources (DER) to distribution secondary spot networks. The original version of this document was written as a request for proposals for research in this area. Subsequent versions have shifted to a broad based performance specification intended to describe the concept functionally. This current version is the second draft of the performance specification for the NPEG concept. It is intended as vehicle for stakeholder discussion and debate. Everything discussed in this document is based in currently available technologies and, in some cases, current practices. The motivation for this performance specification, and the research that it may stimulate, is the desire on the part of public agencies in multiple states to promote the safe deployment of distribute generation (DG) within urban areas which are supplied by secondary network distribution systems. The objective of Massachusetts agencies is to create an inclusive and deliberative stakeholder process which first results in an accepted technical standard and then proceeds to implementation of DG on spot networks. The intent in the technical standards phase of this process is to make this technical information available to any interested party, with the request that MTC be cited as one source of the NPEG concept. For this purpose MTC has worked closely with other agencies, including the California Energy Commission, to initiate an NPEG Collaborative as an informal technical network, open for participation to all stakeholders. The NPEG Collaborative meets in a Webex conference format several times per year. This document is an outgrowth of those meetings. Information on the above can be found at: www.masstech.org/dg/interconnect/network-rfp.htm.

The second draft of this specification contains no new conceptual or experimental data. The control design developed in the original field experiments conducted by William Feero on behalf of MTC in Boston between 2002 and 2005 remains the core topology used. Some background material explaining the fundamentals of secondary spot networks has been added in anticipation of distribution to a wider audience. This material includes an explanation of a currently used approach for interconnection of DG which utilizes customer owned protective relaying. The NPEG schematics have been edited for clarity. Two new variations of the NPEG configuration that employ alternative disconnecting means, such as AC-DC-AC power converters and solid state switches, have been added to illustrate some of the possible options that could be used to meet the requirements of the performance specification. In addition to the new variations, the last section of the document, the material performance specification, has been shortened and simplified. While is this will be a critical part of any final specification, at this time the assumption is that this is best left to be determined on a utility by utility basis, in the spirit of Section 4.1.4.2 of IEEE1547-2003, in keeping with the “practices of the Area EPS.”

This document can be downloaded from:
http://masstech.org/dg/interconnect/network-rfp.htm

Glossary & Abbreviations

DR	Distributed Resources
DG	Distributed Generation
DER	Distributed Energy Resources
EPS	Electric Power Systems
NPEG	Network Protector Enabled Generation
PCC	Point of Common Coupling

In this document the terms, “utility” and “distribution company” are used somewhat interchangeably. While there may be little or no difference in the operational approaches of these two types of business entities when it come to the management of their secondary distribution networks, the tariff implications of the technology being discussed here are significant. The tariff issues, however, are outside of the present scope of this document and thus both terms will be used to mean the same thing.

1 Overview

This document represents an attempt to provide a performance specification for a hardware device and associated set of protocols to facilitate the safe and reliable deployment of distributed generation systems on secondary spot network distribution systems. This specification has evolved from work sponsored by the Massachusetts Technology Collaborative (MTC) in support of the Massachusetts Distributed Generation Collaborative. This DG Collaborative has been investigating ways to interconnect distributed generation (DG) on network distribution systems since 2002, at the direction of the Massachusetts Department of Public Utilities (DPU) and with funding from the Massachusetts Technology Collaborative (MTC) and support from utility and other stakeholders. Specifically this hardware concept is the outgrowth of a two-year research study conducted by William Feero, PE, under contract to MTC, of two distributed generation systems located on a federal building served by a two transformer spot network in Boston, Massachusetts. At present, collaborative discussions are underway to advance the acceptability of DG on networks by developing advanced network protector relays and establishing high-speed communication between network protectors and DG units. This technical approach has been referred to under the headings of, “Advanced Network Protectors,” and, more recently, “Network Protector Enabled Generation” or (NPEG). This document is intended as a framework to facilitate discussions for the development of the NPEG hardware solution.

Building on the June 2006 recommendation of the Massachusetts DG Collaborative to pursue this approach, utilities and state energy agencies in California, New York, and Massachusetts are now coordinating technical projects to develop and test NPEG technology. Current participants in this process welcome the involvement of additional utilities and other technical experts. This document summarizes the history of these discussions and the technical documents which have been recently prepared on this topic. It will serve as the starting point for discussions of experimental design for the next phase of research on this topic.

The core objective of this initiative is to develop a flexible hardware solution to facilitate the installation of distributed generation on spot networks. The chosen approach should be based upon presently available technology, which is currently being used in the area of network protection. In addition to the hardware component, the complete solution should include a body of procedural configurations or applications guidelines for the implementation of distributed generation on spot networks which:

- Avoid negative power flow across the PCC
- Create a system that meets a utility’s most stringent (possibly sub-cycle) coordination requirements
- Create a monitoring and control system with security acceptable to utilities
- And, to the maximum extent practical, create a system that is replicable, scalable and extensible to the widest variety of distributed generation technologies possible.

It is essential to note that the NPEG concept does not suggest or recommend the islanding of DG, either intentionally or otherwise, and does not propose to enable conditions that would contradict the interconnection requirements or operational behavior required by IEEE standard 1547.

1.1 Description of Document Structure

This specification is composed of three main sections, ranging from the most abstract and general to the most specific.

1.1.1 Section 2: Information Model

Section 2 of this document is a high level model that addresses the NPEG concept in the context of the wider energy distribution system and in the context of some of the business functions of the entities that manage it. This contextual or enterprise wide perspective has been taken almost directly from a summary of the IEC Technical Committee 57 Standards [8].

1.1.2 Section 3: Operational Performance Specification

Section 3, Operational Performance Specification, is intended to specify the necessary timing, coordination and information exchange performance characteristics of the NPEG system. This section describes the (proposed/potential) operation of an NPEG system in the context of the present day operational procedures of some utilities and distribution companies and in the context of current network protector performance capabilities. The operational strategies in this section are taken directly from the experimental work conducted at the GSA Williams Building in Boston by William Feero and the body of technical publications of Mr. Feero, et al, on this topic [1, 2, 3].

1.1.3 Section 4: Material Performance Specification

Section 4 is (or eventually will be) the most technically specific, least abstract, of the specification sections. It is intended to specify the material characteristics, in terms of required performances, of an NPEG system down to the component level. In this second version of the performance specification much of the detail of this section has been left to be defined by the prevailing practices of the local utility. However because components of the NPEG system reach across and exist on both sides of the PPC some materials and procedures which are not currently part of the utility's standard practice may need to be developed and specified.

1.1.4 Section 5: Test Specification

Section 5 is a placeholder. The requirements for testing will come directly from the operational and material performance specifications once they are vetted through a stakeholder process.

1.2 Technical Background

In 2002 the Massachusetts DG Collaborative was initiated at the request of the Massachusetts Department of Telecommunications and Energy (DTE) through Order 02-38 to investigate the barriers to distributed generation. The Collaborative consisted of stakeholders interested in and affected by the continued deployment of distributed generation on the electrical distribution system, including utilities, inverter and generator manufacturers, energy users, renewable energy advocates and state agencies, with the Massachusetts Technology Collaborative (MTC) funding facilitation and studies for the process.

One of the issues taken up by the DG Collaborative was that of interconnection of distributed generation on secondary network distribution systems. In an effort to better understand the technical requirements surrounding the interaction of these systems, the MTC hired William Feero PE (presently retired), a well respected consulting engineer in the utility protection field, to provide analysis and recommendations. Based upon his analysis of the objectives of the members the DG Collaborative, Mr. Feero proposed a novel control topology for spot networks that offered the possibility of safely enabling the deployment of significant amounts of distributed generation. The topology has been referred to as the Advanced Network Protector or as Network Protector Enabled Generation (NPEG). This technical approach is described in the following document:

http://www.mtpc.org/dg/2007-02-20-DENP-NEO-draft.pdf

With MTC funding and with the cooperation of NSTAR Electric, Mr. Feero provided technical guidance for implementation of this experimental topology on a two-transformer spot network at GSA federal facility called the Williams Building in downtown Boston. Two forms of distributed generation, a 28kW photovoltaic array and a 75kW gas-fired Tecogen CHP induction generator, were installed at this building. Eaton Cutler-Hammer designed and installed a custom auxiliary control unit in the transformer vault serving the building. The control unit monitored the two network protectors for underpower conditions and, in the event of such a condition, had the ability to force a trip of the Tecogen unit. The Williams Building tests were run from May, 2003, to March, 2005. After nearly two years of monitoring, the study concluded that:

- there are no ratings or types of generation interconnection above the reverse power setting of the network protector relays that can be installed on spot networks without some system fault condition exposing the protectors to undesired trips;
- photovoltaic systems with ratings less than 30% of the minimum loading of the network will have the lowest probability of experiencing a system fault that would result in an undesired trip;
- some form of sensing must be provided in each network unit circuit to assure tripping of the interconnected DRs under all network conditions.

This May 2005 report can be accessed at:

http://masstech.org/dg/2005-05-31-FeeroNetworkReport.pdf

As part of its June 2006 report, the Massachusetts DG Collaborative developed the Advanced Network Protector concept (described in Attachment F) and recommended that this technology be developed and tested soon with the support of MTC and other funding agencies and with the cooperation of Massachusetts utilities. These 2006 documents can be downloaded at:

http://www.masstech.org/dg/collab-reports.htm

1.2.1 Problem Statement

As distributed generation becomes more common, utilities and distribution companies are more frequently being asked for interconnection of these systems. Some of these requests for interconnection are being made in sections of the grid where the distribution is configured as either a spot or a grid network system[1]. Interconnection to these types of secondary distribution networks presents special challenges to operational safety, power quality and reliability. Presently there is no single standard or universally accepted policy for these interconnections. Figure 1 below shows a two transformer spot network under normal operation. The building load, typically a single large customer such as an office tower or convention center, is served by two parallel transformers which step the primary distribution voltage down to a utilization voltage of 208 or 480 volts. The spot network shown here has only two transformers, however there could be several more.

Figure 2 illustrates the same two transformer spot network with a fault on the primary distribution feeder supplying one of the transformers. In the case where a fault occurs on the primary side of a network protector transformer power can flow backwards (reverse) from the secondary 480 (or

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[1] There are a number of different terms used to describe "grid" network configurations. Among them are, "street" networks and "area" networks. In this report we will use the IEEE terminology, "grid" network.

208) volt bus, through the transformer to the fault. The network protector system is designed so that the fault is isolated because both the primary fault protection opens and the network protector of the affected transformer opens. The load, however, continues to be served by the remaining network protector transformer and the customer experiences uninterrupted service.

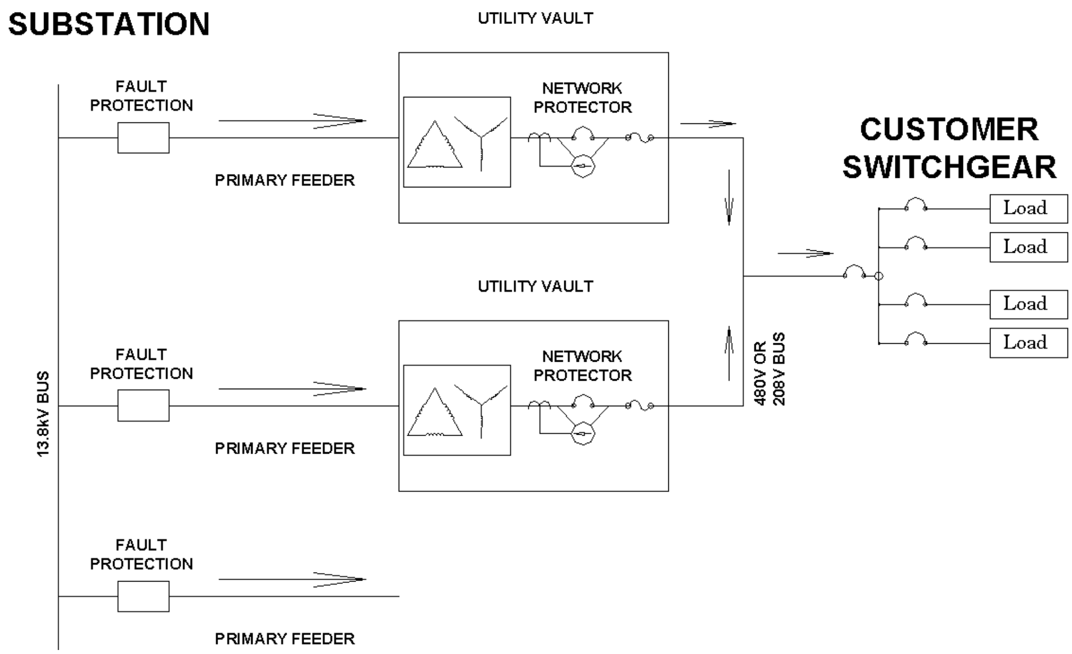

Figure 1: Normal operation of two transformer spot network, no customer-sited DG

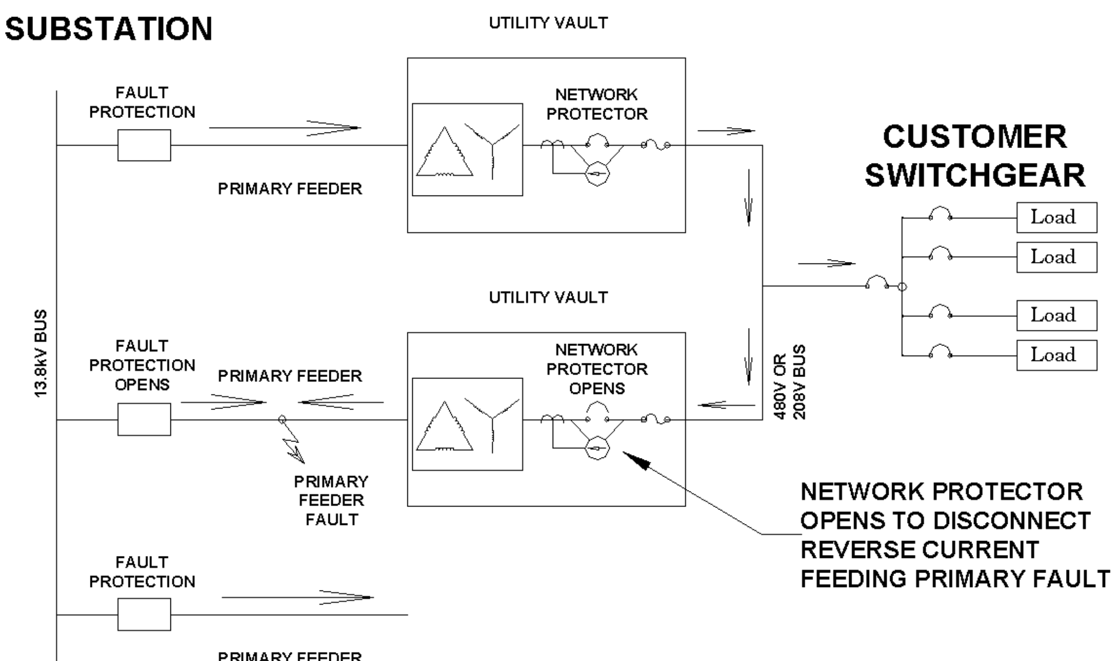

Figure 2: Normal response of network protector to primary feeder fault. Customer service continues uninterrupted.

The fundamental difficulty in connecting distributed generation technologies to secondary distribution spot networks lies in the fact that the protection systems for spot and grid networks are not designed to accept reverse power flow from the customer's facility going back in the direction of the utility. The network protector "perceives" the normal reverse power flow from a DG source as a fault.

Even under normally occurring light load conditions, absent customer sited generation, it is possible for network protectors to open. Generation located on grid or spot networks has the potential to exacerbate this condition and by doing so cause network protectors to open when not intended[2]. If the network protectors are opened they may not reliably re-close once the load has returned and the building may be left without electrical service. There are two scenarios which have been identified as potential problems that can be caused by DG on spot networks. The first occurs under normal operating conditions of the spot network, and the second occurs as a consequence of a fault on the primary distribution side of the network.

1.2.1.1 Reverse Power: Normal DG Operation

Under normal operating conditions it is possible for a spot network facility to be so lightly loaded that one or more of the network protectors will open due to imbalances or mismatch in the impedance of the network protector transformers. The addition of generation on the customer side of the point of common coupling only exacerbates this problem by further reducing the facility load. But more fundamentally, distributed generation systems, by design, are intended to generate in parallel with the electrical power system (EPS) and thus, under normal operating conditions, to export power to the EPS. Absent some form of monitoring and control scheme for the DG, if the load on the customer's side of the PPC is less than the level of generation of the DG energy will be exported to the utility and the network protector will open.

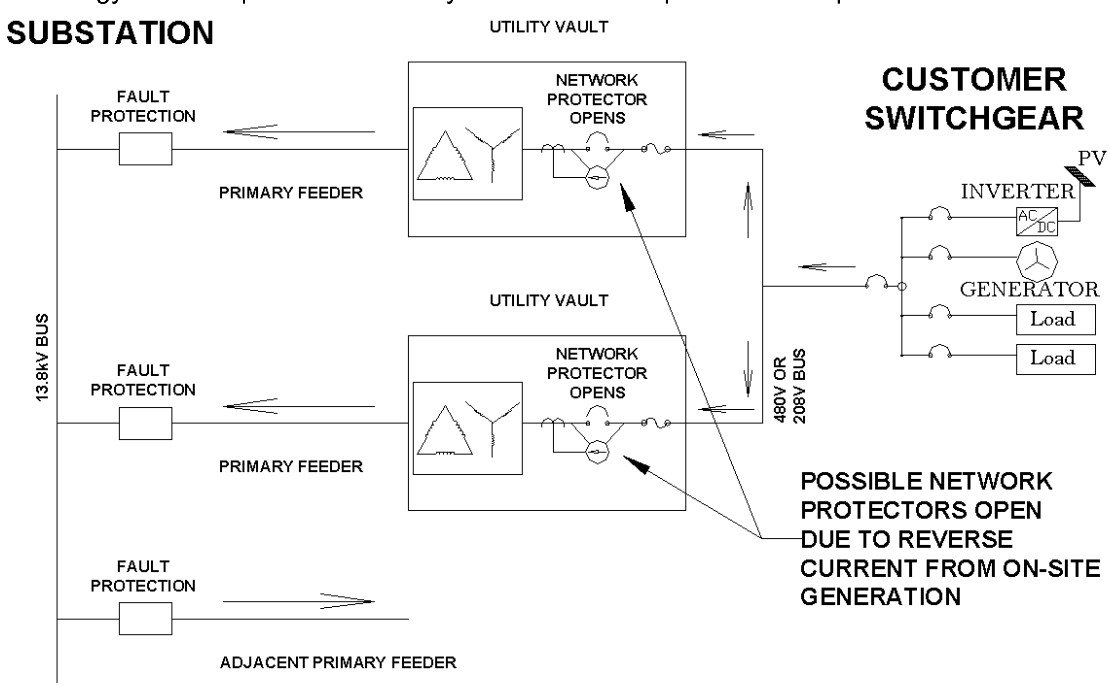

Figure 3: Network protector opening due to normal DG operation during light load condition.

[2] For a more detailed explanation of the issues surrounding the interconnection of distributed resources on networks see: http://www.mtpc.org/RenewableEnergy/public_policy/network/2006-04-05_Feero_Network_review.pdf

1.2.1.2 Reverse Power: Adjacent Feeder Fault

Another scenario that was discussed in the Williams Building study was that of the impact of DG on the system during a fault on an adjacent feeder on the primary network supplying power to the secondary distribution system. In such a case, the effect of customer-sited generation could be to supply power to the fault through the transformers of the secondary system. In the case of rotating equipment, such as induction or synchronous generators, that fault contribution could be several times its rated output. The argument is that as the voltage on the primary bus collapses, the fault contribution of the DG will cause a momentary reverse power flow across the network protectors and cause them to open. The response time of the network protector can be fast enough so that the primary feeder fault protection will not have time to respond and isolate the fault before the adjacent network protectors open.

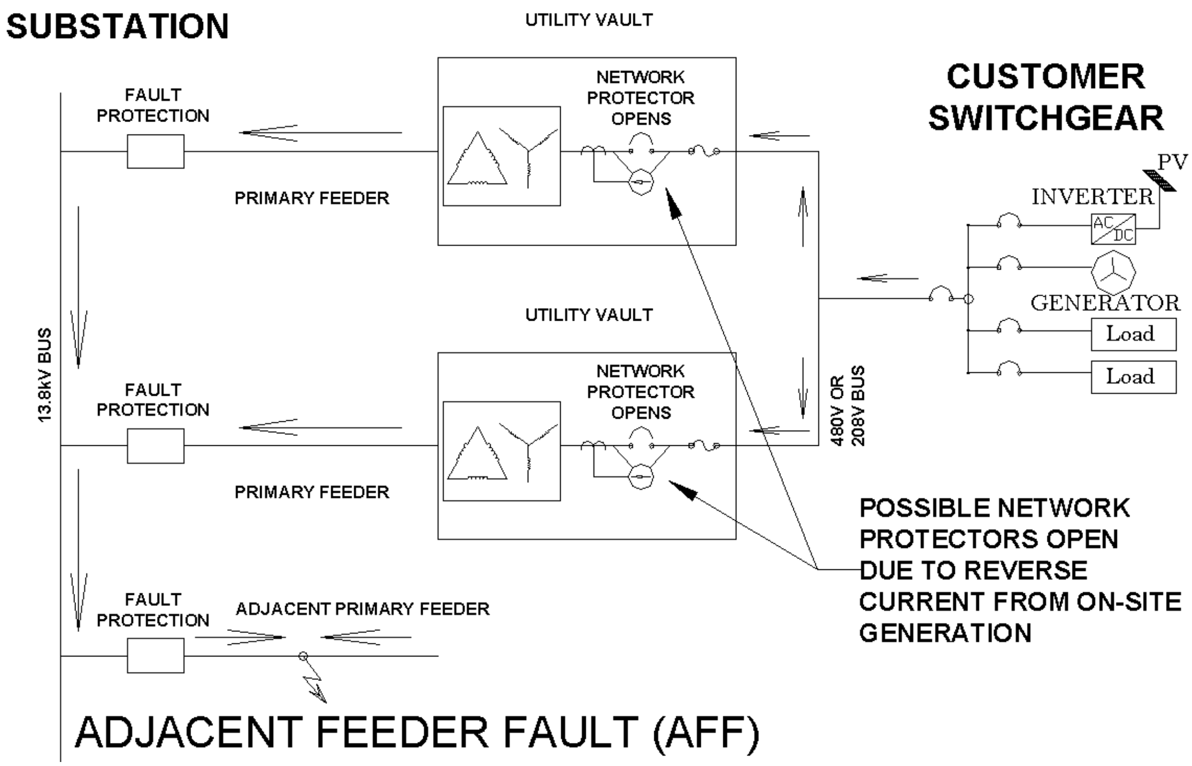

Figure 4: Network protectors open during fault on adjacent feeder due to DG fault current.

1.2.2 Current Interconnection Practices for DG on Networks

Currently most utilities and distribution companies which operate secondary distribution networks prohibit or significantly limit the interconnection of DG on their networks. One standard being used in Massachusetts limits the size of DG interconnected to a spot network to 1/15th the minimum building load unless a formal interconnection study is conducted. When distributed generation systems are permitted to interconnect one of the common approaches is to monitor and control the generating source using customer owned and maintained protective relays. Figure 5 illustrates a typical configuration of this type of interconnection. Some of the drawbacks and limitations to this approach which have been expressed by utility personnel revolve around the fact that this equipment is relatively specialized and requires training that is not a part of the normal maintenance personnel skill set, or even that of the vast majority of electrical contractors. In addition these systems must be programmed to utility threshold specifications and then tested and certified using specialized equipment by independent third party testing companies. Once tested, the utility needs some form of assurance that the program has not been altered with values outside their prescribed ranges. Every few years these relays need to be re-tested;

however, for some system owners there may be little incentive to be vigilant about relay maintenance.

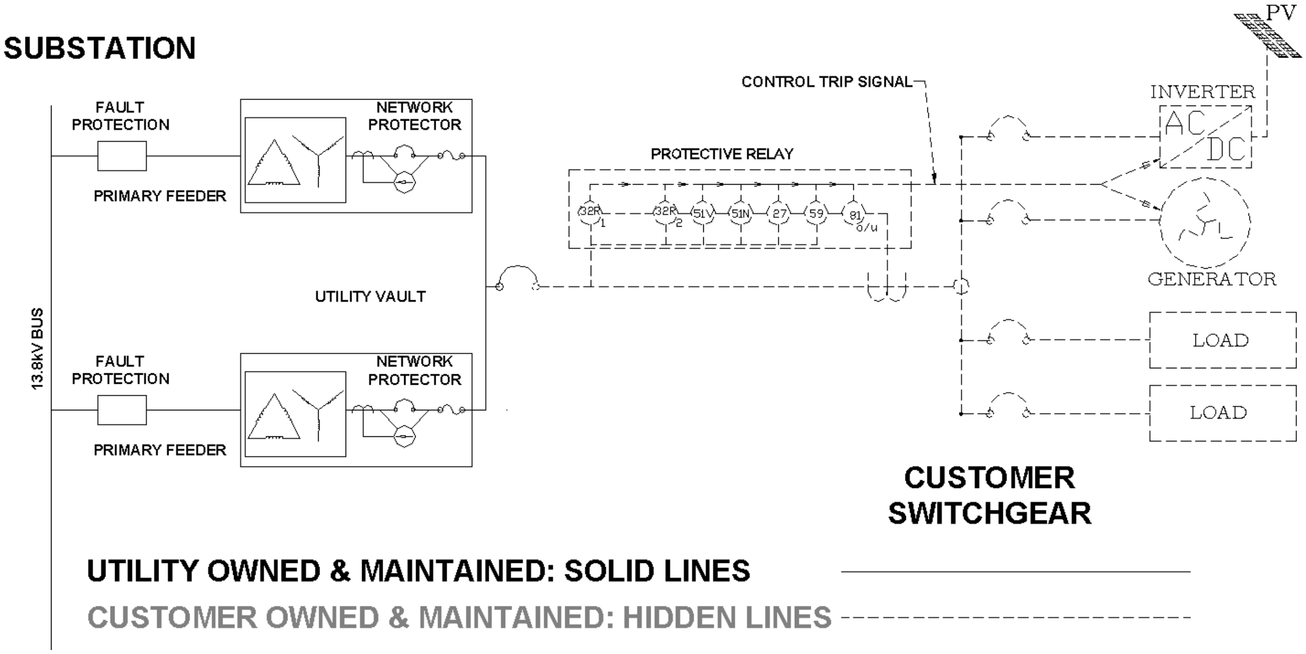

Figure 5: Current practice for DG on spot networks using customer-owned protective relay

1.2.3 NPEG Conceptual Solution to Permit DG on Spot Networks

The conceptual solution to the problem of DG on secondary network distribution systems being proposed here is to insert control of the DG on the utility side of point of common coupling (PCC). The fundamental objective is to eliminate, as far as is practical, the possibility that operation of a distributed generation technology on a spot network will result in the unintended opening of a network protector and the associated loss of service to the customer. The proposed method for accomplishing this goal is to transfer a portion of the control of the distributed resource, in the form of a "Go/No-Go" signal, to the utility through an enhancement of the presently available network protector technology. That control would reside with the network protectors on a spot network, through an auxiliary relay controller referred to as a Master Control Unit (MCU). Control and monitoring signals would cross the PCC and have the ability to trip the DG in the event that either:

1) the number of network protectors that are closed is 50% or less;

2) the forward power across the network protectors is less than a preset threshold;

3) there is reverse power across the network protector (two Reverse Thresholds, RT_1 and RT_2: with optional programmable delay and instantaneous trip).

Besides the fact that the sensing and decision making capability is owned and maintained by the utility, the NPEG concept suggests that this equipment be located in the utility's transformer vault or some other secure, utility controlled location. In addition the basic relay functions, the communications link –an all dielectric fiber optic line-- between the MCU and the DG will be utility owned and maintained.

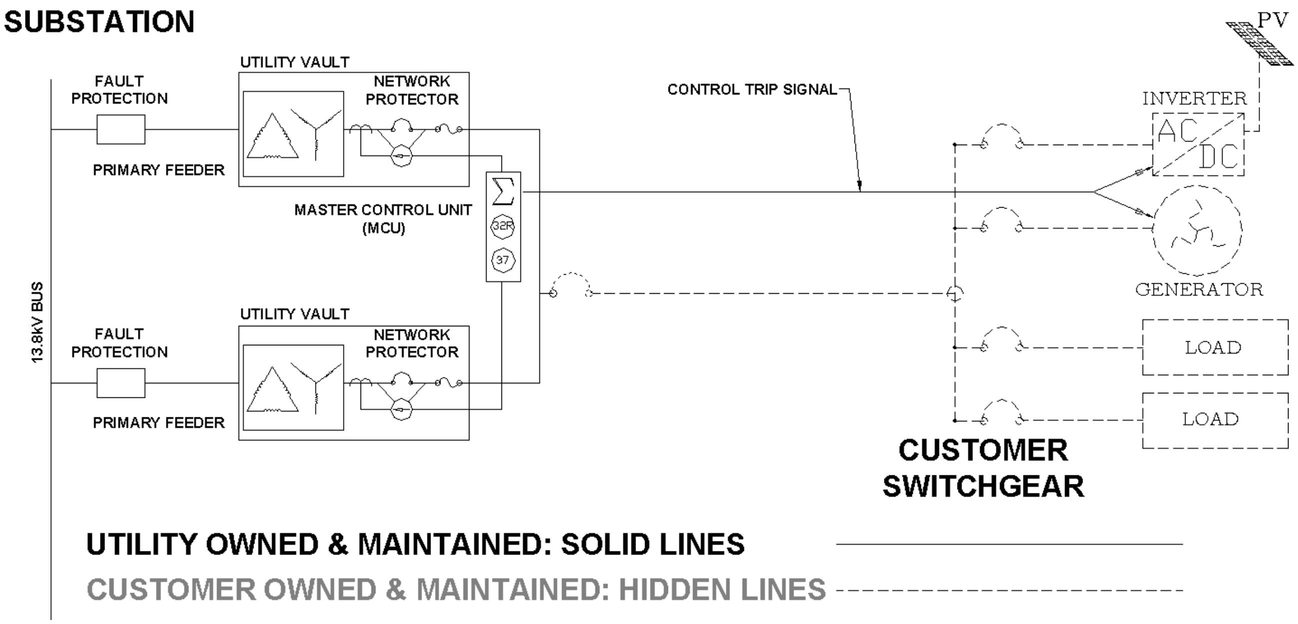

Figure 6: NPEG conceptual solution for control of DG

The NPEG topology could work with any form of DG, including rotating equipment, however it may be necessary to employ a variety of specialized interfaces for machine based systems in order to achieve the necessary –potentially sub cycle-- disconnecting times. One such approach to fast disconnecting time would be to use some form of power conversion technology, such as an ac/dc/ac converter. The ac output of the generation source would be rectified, then inverted to achieve the fast disconnecting times required.

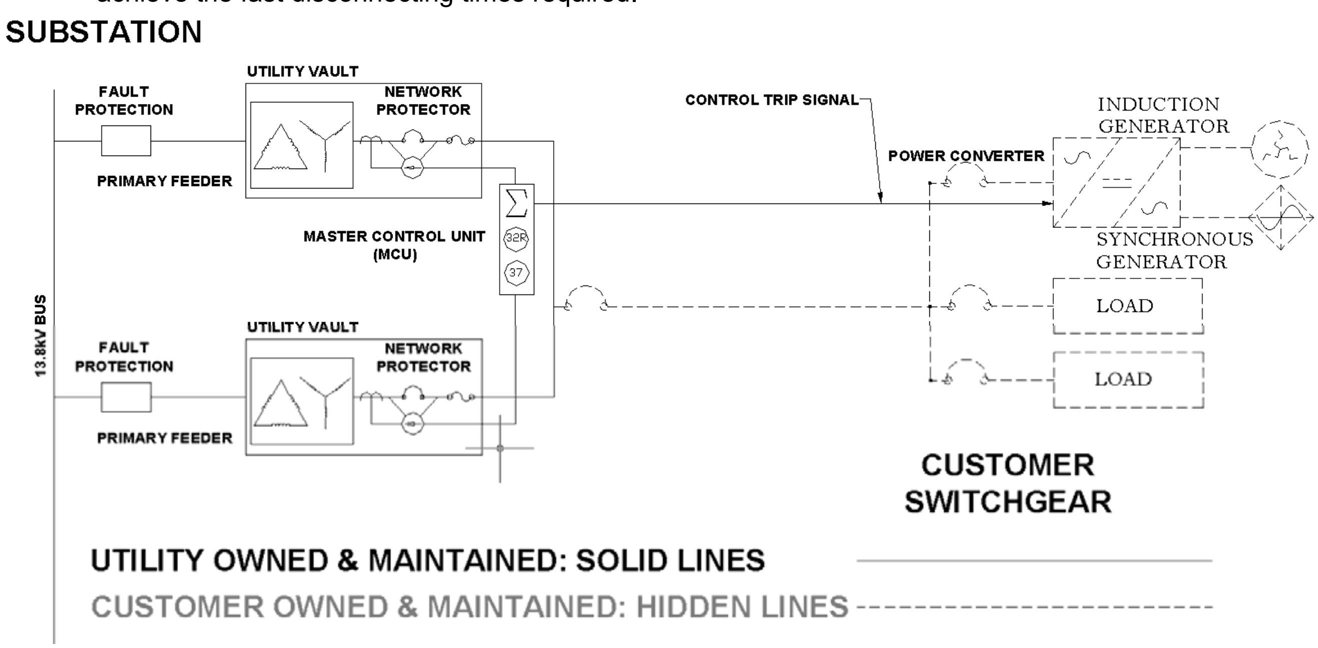

Figure 7: NPEG variation using a "Power Converter" approach for fast disconnect of machine-based systems.

Another method for fast disconnection is to connect the output of a rotating device to a solid state switch with the required power characteristics.

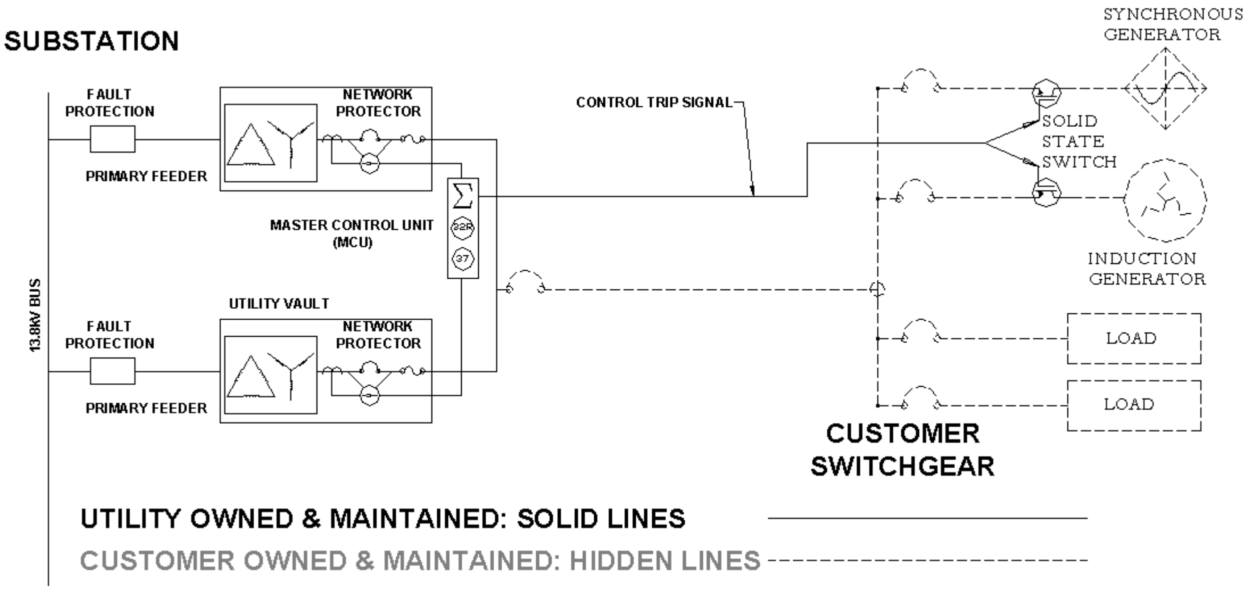

Figure 8: NPEG variation using solid state switch for fast disconnection of machine-based systems.

1.3 Reference Standards

The standards that are relevant to this development effort are listed below. IEEE 1547-2003 is the core standard on which this development effort is based. It is the most well established and nationally accepted of the standards and was developed through a very broad consensus process. C57.12.44 is both an IEEE and an ANSI standard and pertains primarily to the physical specifications for network protectors. IEEE 1547.3 is a standard that defines data monitoring and control functions for distributed resource technologies. IEEE 1547.6 is under development by IEEE standards working group and deals specifically with interconnection of DR to secondary network distribution systems. Because the data transfer component of this system crosses the PCC that portion of the system which is on the customer's property must comply with the requirements of all local building codes. For electrical issues the National Electrical Code will be the relevant standard in most jurisdictions.

In addition to these standards, for any actual system being installed in the field, there will likely be a number of other local standards that may be applicable. The intent of the NPEG performance specification is to provide a conceptual topology, an operational strategy, and the definition of a set of operating parameters, but to leave the precise setting of thresholds to the discretion of the local utility practices.

1.3.1 IEC TC 57 Standards

The International Electrotechnical Committee (IEC) is a global standards organization focused on electricity, electronics, and other related topics. The IEC is subdivided into separate Technical Committees (TC) each with specific domains. The IEC Technical Committee 57 is focused on power system management and associated information exchange. TC 57 is further divided into Working Groups (WG). These working groups define standards that govern the interconnection of individual components. They do not attempt to create standards for design of these components, but rather the interconnection of these Intelligent Electronic Devices (IED) and software applications that interact with these devices. This Committee precisely defines an abstract information model and attempts to standardize the way to implement the business processes. The NPEG Performance Specification borrows heavily from the approach of TC 57 for the structure of this document and especially for the model of information exchange on the enterprise level.

IEC TC 57 WG 10 is a working group that focuses on power system IED communication and associated data models.

IEC TC 57 WG 17 is a working group that focuses on communications systems for distributed energy resources.

1.3.2 IEEE 1547 2003

IEEE 1547-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, is the fundamental reference standard for this development process [4]. The DR technologies considered for participation in this initiative must comply with the requirements of 1547. 1547 gives little guidance for interconnection of DR on spot networks (and no guidance at all for grid networks at this time.) Five of the six requirements for spot networks do pertain to the NPEG concept:

"4.1.4.2 Distribution secondary spot networks

Network protectors shall not be used to separate, switch, serve as breaker failure backup or in any manner isolate a network or network primary feeder to which DR is connected from the remainder of the Area EPS, unless the protectors are rated and tested per applicable standards for such an application.

Any DR installation connected to a spot network shall not cause operation or prevent reclosing of any network protectors installed on the spot network. This coordination shall be accomplished without requiring any changes to prevailing network protector clearing time practices of the Area EPS.

Connection of the DR to the Area EPS is only permitted if the Area EPS network bus is already energized by more than 50% of the installed network protectors.

The DR output shall not cause any cycling of network protectors.

The network equipment loading and fault interrupting capacity shall not be exceeded with the addition of DR."

This section of the standard represents the most basic requirement for the NPEG concept.

1.3.3 IEEE 1547.3 2007

IEEE Std 1547.3, "Guide For Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems," was published in 2007. This is a communications standard for distributed generation systems[3] [6]. This standard is theoretical and broad in it scope. It is written in extremely general language, covering a range of topics from meta-issues of interoperability and extensibility to more specific topics of security and protocols for data exchange. The communications solution for an NPEG type system will need to comply with the broad principals outlined in 1547.3.

The universe of monitoring and control protocols is vast. Appendix B of 1547.3, "Annotated list of protocols," describes a wide range of data formats, both generic and proprietary. Any utility choosing to implement an NPEG configuration will likely adopt information protocols and

[3] Note that the standard specifically refers to "Monitoring, Information Exchange, and Control" and omits the term "communication." This is intentional as "Communications" is a large and distinct area of standards development within IEEE.

standards which best fit their installed hardware and software base. Aside from the all dielectric nature and the security features of the system the NPEG concept is system/protocol independent.

1.3.4 IEEE P1547.6

IEEE P1547.6,"Draft Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks," deals specifically with the technical requirements for interconnecting distributed resources to spot or grid networks. Any implementation of an NPEG type configuration should reflect the recommended practice of this document once it has been ratified.

1.3.5 IEEE/ANSI C57.12.44 2005

The current version of this standard is IEEE/ANSI C57.12.44-2005 [5] Requirements for Secondary Network Protectors. Any implementation of an NPEG type design solution must not violate any of the requirements of this standard.

1.3.6 California Electric Rule 21

Interconnection of Distributed Resources on Secondary Network Distribution Systems.

1.3.7 NFPA 70 - National Electrical Code

Unlike most other utility or distribution company devices the NPEG Data Exchange & Control link transverses the point of common coupling and enters the customer site. As such, portions of this system will fall under the jurisdiction of the locally adopted electrical Code. In most cases, within the United States, this is the National Electrical Code.

1.4 Organization of Research & Development

The NPEG concept is essentially a merger of several established technologies integrated in a novel configuration. As such any implementation of the performance specification described in this document is still partially experimental and thus must meet the operational constraints of the local utility or distribution company. Issues such as maximum delay time for network protector opening (or use of any delay at all), physical data interface, data protocol, and trip coordination must be resolved without compromising the approved procedures, functionality or listings of any of the interacting systems. In terms of critical technology the three major stakeholders in this process are the utilities and distribution companies, the network protector manufacturers, and the manufacturers of distributed generation systems. In addition to the material and operational constraints that derive from the design of the equipment and operational practices of these stakeholders, an NPEG solution must also comply with the prevailing standards that pertain to both network protector technology and interconnection of distributed resources to electric power systems.

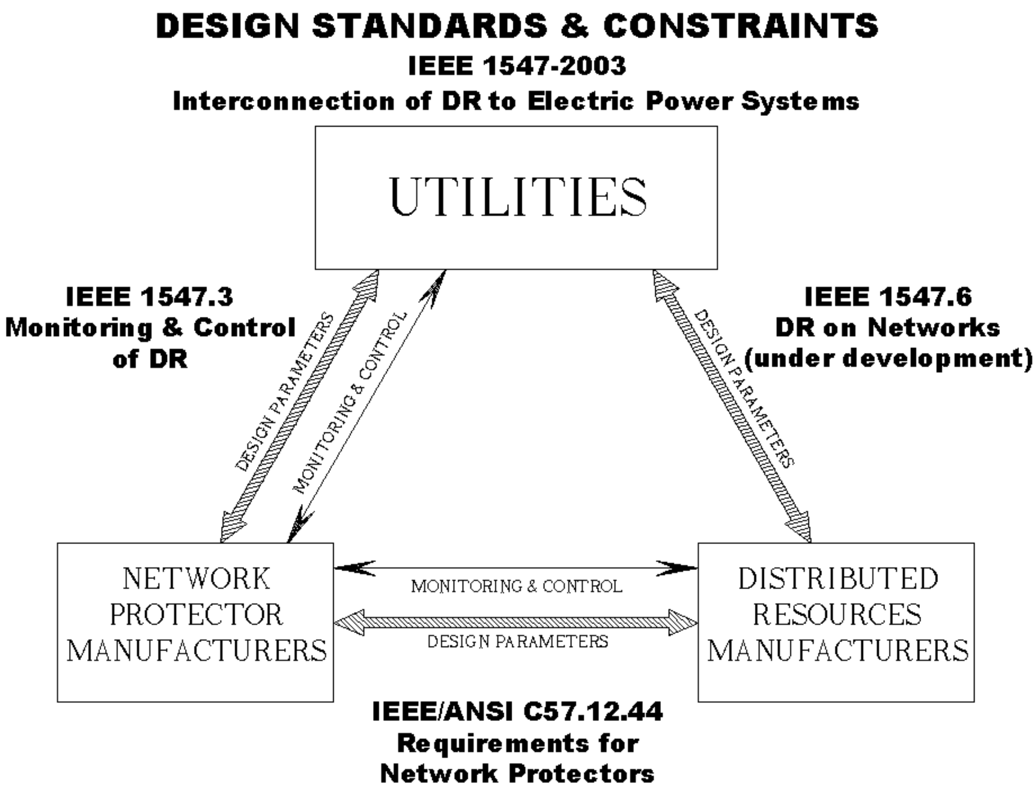

Figure 9: Primary NPEG interactive components

The graphic in Figure 9 illustrates the relationships between and amongst the primary stakeholders and prevailing technical standards.

1.4.1 NPEG Collaboration

In December of 2006 New Energy Options, Inc. (NEO) was hired by MTC to support the procurement and testing of this NPEG technology. NEO's role is to assist with identification of and outreach to other potential stakeholder agencies, to solicit ideas and participation, and to assist with the development of the technical details of future procurements. In this capacity New Energy Options has met with staff members at the California Energy Commission and presented the advanced network protector concept in December 2006. In February of 2007 NEO presented the NPEG concept to the IEEE SCC21 1547.6 Working Group which is developing interconnection standards for DG on network distribution systems. All the presentations and other materials developed by this project can be found at:

http://www.masstech.org/dg/interconnect/network-rfp.htm

In April, May, June and October of 2007 a group of stakeholders[4] from three states participated in a web conference call to explore possible ongoing collaboration and roles for interested parties. Presentations of the work to date were made and the issue of a possible mechanism for administering a collective RD&D effort was discussed. The meetings concluded with agreement

[4] Participating entities included the Massachusetts Technology Collaborative (MTC), the California Energy Commission (CEC), the New York State Energy Research Development Agency (NYSERDA), the Massachusetts Division of Energy Resources (MA DOER), National Grid Service Company, Pacific Gas & Electric (PG&E), Electric Power Research Institute (EPRI), BEW Engineering (CEC consultant) and New Energy Options (MTC consultant).

to continue this collaboration through additional calls with the objective of coordinating the technology development activities of multiple states and utilities. This performance specification was an action item of the June conference call and is intended as a framework for discussions and experimental design in the research going forward. Since then several stakeholders have moved forward with various relevant initiatives:

• NPEG Collaborative multi-state phone calls held on 4/21, 5/25, 6/13 and 10/3 of 2007. The next one planned for late February.

• PG&E has applied for matching funds for data monitoring of an existing large DG connection on a spot networks territory. This effort is expected to provide useful information for future connection of DG to spot networks.

• A site visit conducted at the GSA Williams Building where the NPEG concept is installed to further understand its design and performance. NStar participated in the site visit. The Massachusetts Department of Energy Resources (DOER) expressed at this meeting the Commonwealth's interest in pursuing technical solutions to real-world opportunities for DG interconnection on secondary networks. The NPEG performance spec was updated based on this visit.

2 Information Model

2.1 General

This section is intended to provide a high level system model for the NPEG concept. The objective is to illustrate the potential interaction and integration of the proposed system with the distribution company's wider operational enterprise. The model, at this level, treats as abstractions, the exchange of information and control. This section references broad business and operational objectives, as well as high level technical standards, but is technology independent.

2.2 Distribution Company Business Process

The conceptual model illustrated in Figure 10 is adapted from an IEEE document, "Focus on the IEC TC 57 Standards." The figure shows the basic relationships of information exchange and control. An example of the type of communications that could occur at this level might be a "Trouble" signal from an MCU. The trouble signal does not indicate that the MCU has tripped the DG, but just that some aspect of the system status has moved outside of normal specifications. An example of such a trouble signal might be a loss of the supervised communications link between the MCU and the DGI. In the NPEG concept the presence of this link is continually verified through some form of "hand shaking" protocol. The absence of a signal verify that the link is functional would be reported not as an alarm but as trouble signal. Possible responses to such a signal, at the enterprise level, might be to initiate a work order for a service call, to update the system records database or run a diagnostic program for the MCU, or to contact the customer to require shut down of the DG until the initiating event has been corrected and the trouble signal cleared.

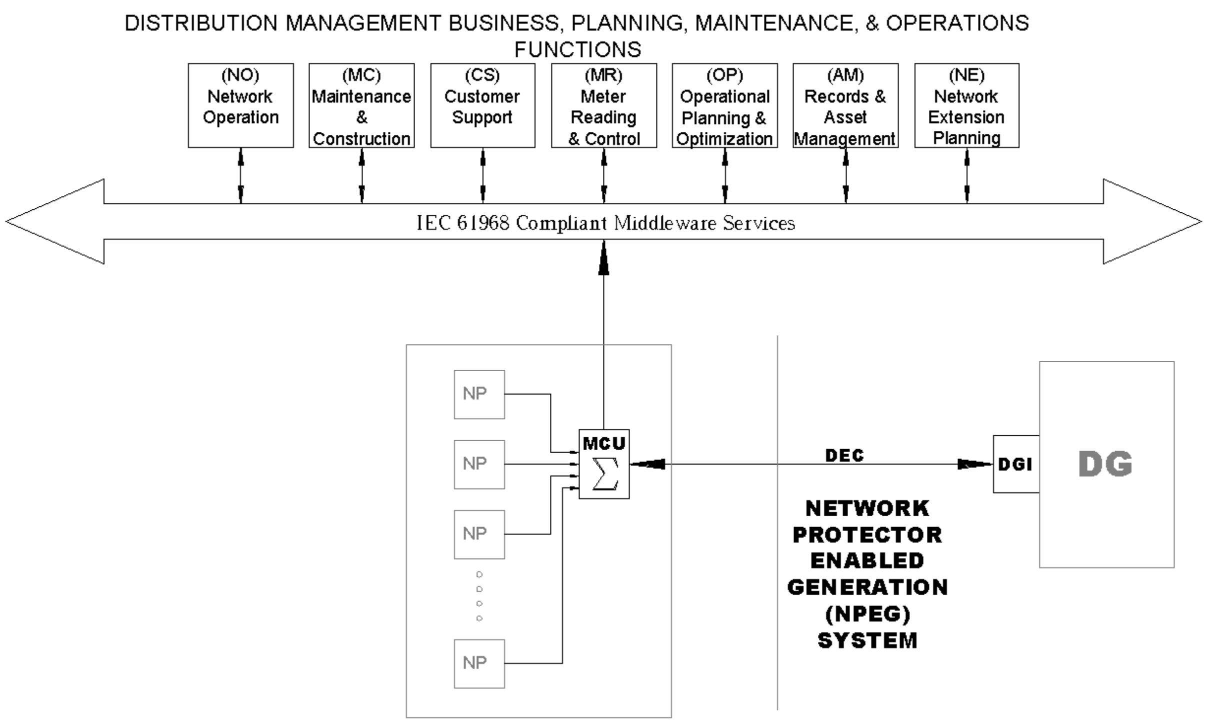

Figure 10: NPEG information exchange with distribution company enterprise network (IEC TC 57 framework)

An overarching objective of the NPEG concept is that it in no way compromise the premier quality of service and level of safety that the present network protector technology provides. To achieve this any exchange of information between existing network protectors and NPEG equipment will be configured as “Read-Only” with no alteration of the network protector’s original functionality.

3 Operational Performance Specification

The intent of this section is to describe the operational parameters that pertain to the NPEG device in the context of its role as a control mechanism for the distributed generation unit. It is important to note that this concept has nothing to do with islanding of DG. Fundamentally the NPEG concept places control for curtailment of the distributed generation source with the utility or distribution company. There are three fundamental criteria for sending a cease-to-energize command to the DG.

3.1 NPEG Zones of Operation

This NPEG configuration conceives of three modes or zones of operation for the protection protocol [3]. These three zones of operation represent three different responses by the network protector controller to directional power flow measured at the network protector. The response by the network protector, which is dependant upon the direction and magnitude of the power flow, effects the tripping of the customer sited DG and the decision of whether and when to open the network protectors. The three zones are:

1) Forward Underpower: delayed DG trip (P_U)
2) Low Reverse Power: DG trip with network protector optional delayed opening (RT_1)
3) High Reverse Power: DG trip with network protector instantaneous opening (RT_2)

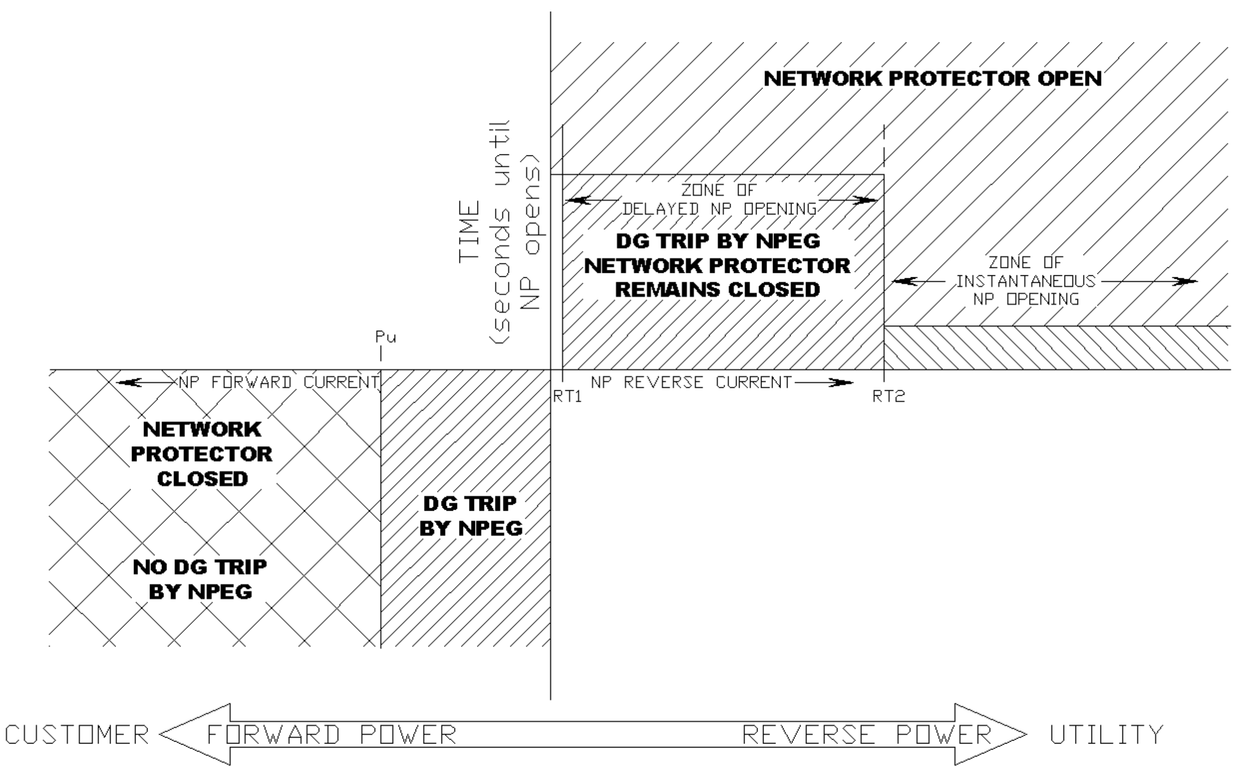

Figure 11: NPEG time/power protective schema

For the diagram in Figure 11, time is represented on the vertical axis and directional power on the horizontal. The time axis above the horizontal axis, expressed in seconds or cycles, is positive elapsed time between detection of reverse current and the point at which the network protector opens. Time below the horizontal axis represents all past time before the detection of a reverse power event. The horizontal axis represents power flow toward the customer (forward) on the left of the vertical axis and power flow back to the utility (reverse) to the right of the vertical axis.

3.1.1 Forward Underpower Threshold

Protection in the forward underpower zone is a kind of safety margin of operation. The intent is to monitor the flow of power across the network protectors and if the forward flow drops below a predefined threshold the network protector control unit will send a trip signal to the DR dropping it off line. This would be a preemptive control measure that would be invoked before any abnormal occurrences on the network and prior to any actual reverse power flow at the network protector. In response to this temporary shut down of the on-site generation the net load (forward power into the facility) will increase above the forward underpower trip threshold. To avoid cycling the generating source the threshold to restart the DR, P_O, will be set higher than the trip threshold, there by designing hysteresis into the control system.

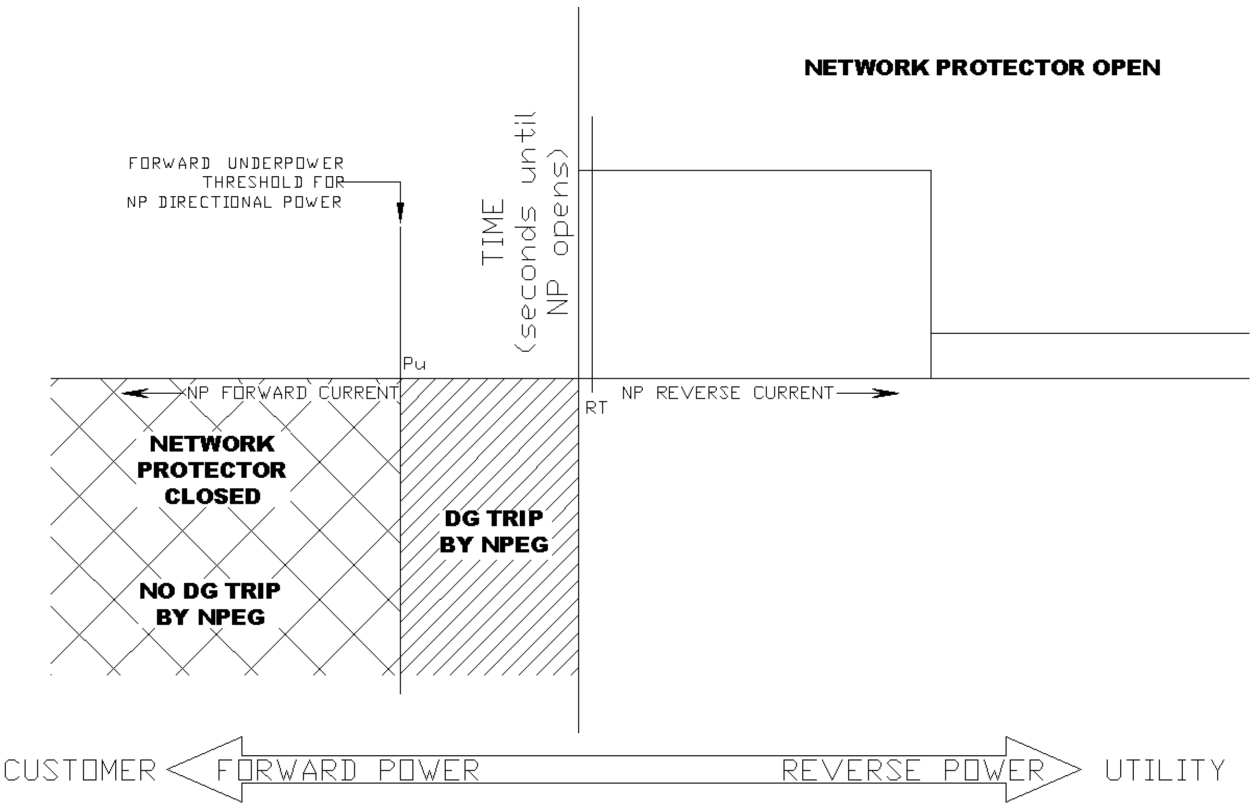

Figure 12: Forward underpower NPEG DG trip configuration

The intent of the NPEG concept is that the forward underpower threshold be an adjustable setting suited to the specific characteristics and requirements of the network and the DR in question. Related concepts have been discussed including a 2-stage configuration where the higher threshold provides a warning signal of some kind to the DR or the customer’s on-site energy management system. Another concept that has been discuss, but which is outside the scope of this current specification, is for the network protector to have some form of continuous control over the DR with the ability “throttle back” the energy production at times of low forward power.

3.1.2 Reverse Power: Delayed NP Opening

For low current faults[5] on the primary network the NPEG concept envisions the use of an adjustable time delay in the control mechanisms that opens the network protectors. This approach has two main parameters that govern its operation. The first parameter is the reverse current threshold for which the network low voltage bus can tolerate short term voltage sags. This threshold is expressed as a percentage of the full rating of the network protector transformer. The report, "Generation Monitoring at the GSA Williams Building and Modeling of Feeder Fault Cases Recorded," provides a formula for calculating this value. The selection of the reverse current threshold will derive from the specific physical characteristics of the network transformers and the risk tolerance of the utility.

The second selectable parameter is the length of the time delay itself. The intent of the time delay is to provide sufficient time for the DR to cease to energize the system after it has received the trip signal from the network protector controller and before the network protector opens due to reverse power. The objective is to select a time delay that will be greater than the cessation time of the DR with minimum necessary margin to assure coordination, thus avoiding an unnecessary network protector opening. This parameter will be defined by the physical characteristics of the DR and its associated disconnecting mechanism, and the network, as well as the risk tolerance of the utility.

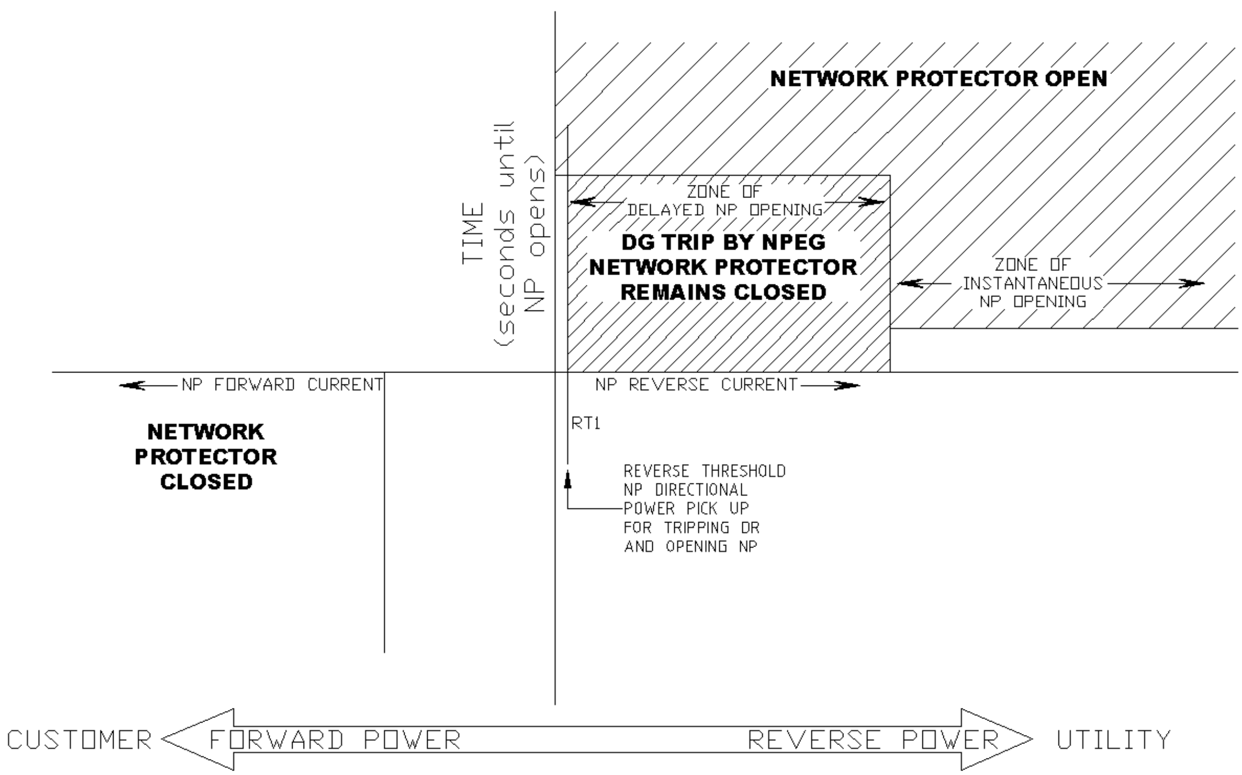

Figure 13: Network protector optional delay in opening while tripping DG

Without specific units, figure 13 illustrates the zone of operation for reverse power levels that are sufficiently low to permit time delay. In the case of the GSA Williams building the time delay was 15 cycles. The threshold defining "low reverse current" was set at 50% of the rating of one network transformer.

[5] The definition of what constitutes "low current" will likely be decided by the local utility protection engineers. The research conducted at the GSA Williams building suggests an analysis based upon a percentage of the network protector transformer rating.

3.1.3 Reverse Power: Instantaneous NP Opening

For high current faults, those in excess of preset limits established by the local utility, the network protector must open instantaneously in order to protect the spot network service and other elements of the larger network up stream. The latency shown in this zone of operation (the short vertical band above the horizontal axis) is only the intrinsic mechanical delay between the time at which reverse current is detected and the time at which the network protector opens. This is in the range of three to six cycles. For utilities that do not presently permit time delays on network protectors this would be the zone of operation regardless of the magnitude of the reverse power.

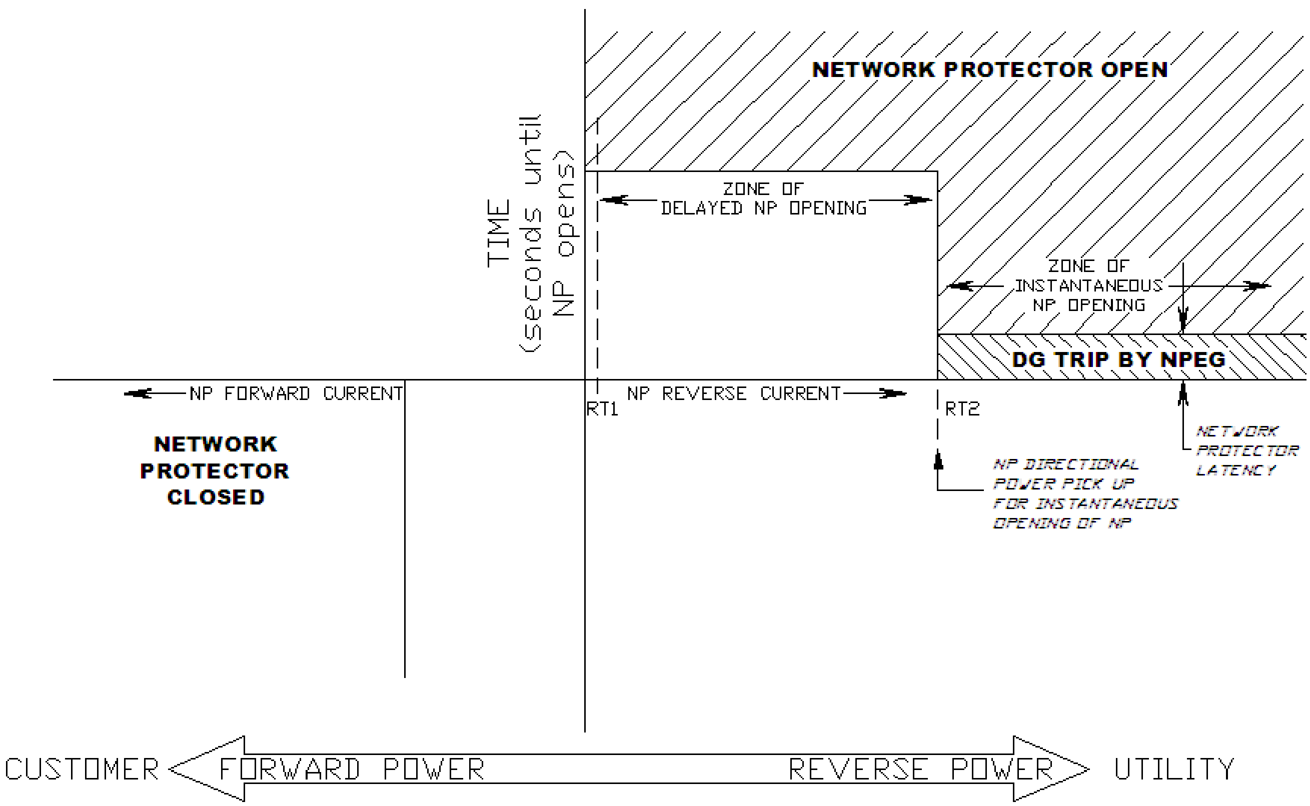

Figure 14: Network protector instantaneous trip zone

3.1.4 Time-Current Coordination of DG Tripping & NP Opening

A key feature of this control configuration is the necessary coordination of network protector status (closed/open) and DR system trip times. The time required for opening for a network protector can be on the order of three to six cycles [2]. In the GSA Williams building study, with permission the utility, a delay of 15 cycles was programmed into the Cuttler-Hammer unit microprocessor control. For reverse power conditions that were less than fifty percent of the network protector transformer's rating, rather than opening immediately after detection of the condition the network protector sent a trip signal to the DR and waited 15 cycles before opening[6]. If the power contribution by the DR ceased in less than 15 cycles, resulting in a changed of

6 In engineering terminology this threshold is expressed on a "per unit" basis (p.u.). This is a system by which values, such as power, current, voltage, etc., are referenced or scaled to a base value. In the case of the parameter of reverse current it is referenced to the rated current of the network protector transformer. The value of the reverse current for which a time delay was permitted at the Williams building was 0.5 p.u. (50%) of the network transformer full current rating.

direction of power flow across the network protector from negative to positive, then the network protector would not open.

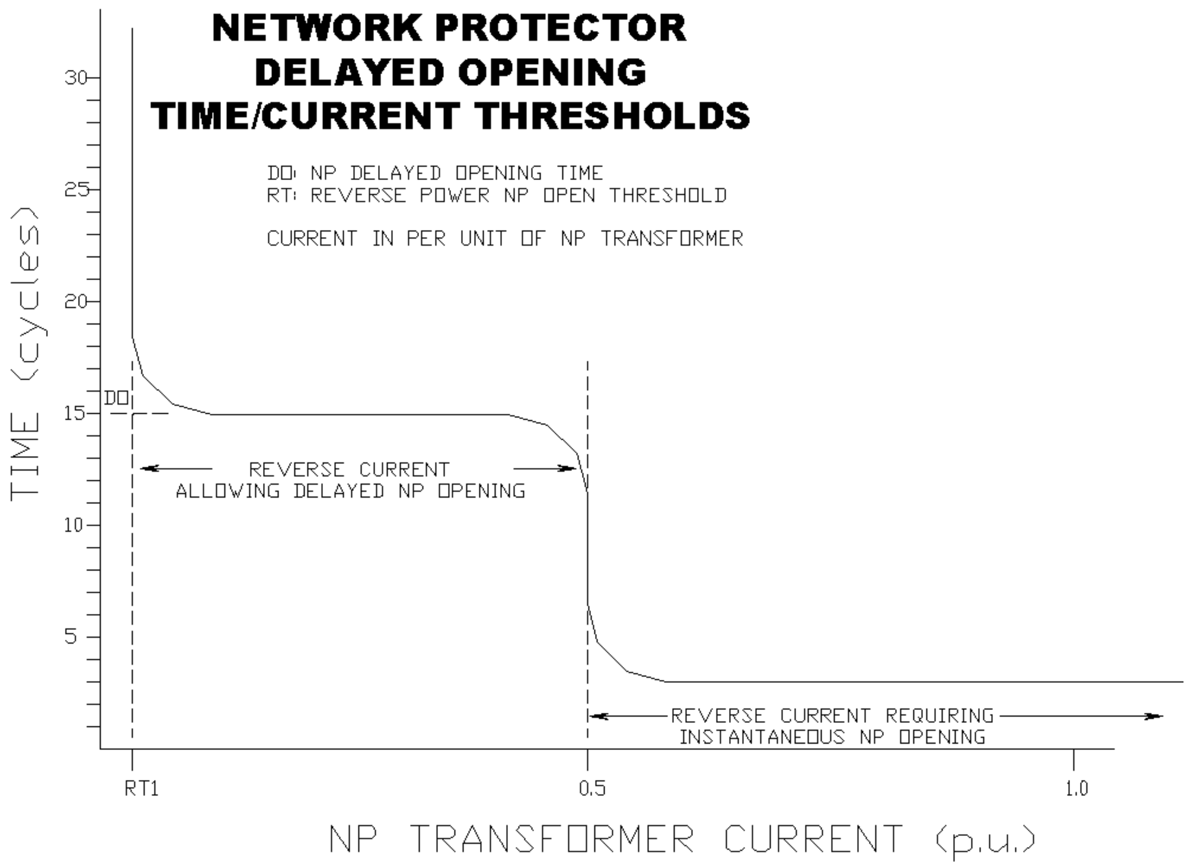

Figure 15: Delayed opening of network protector for predetermined level of reverse power

This time delay window was used to assure that the trip signal from the CH unit to the DR resulted in the cessation of current from the DR before the initiation of the network protector opening. For reverse currents greater than 50% of the rating of the network protector transformer the network protector was set to open instantaneously (no intentional time delay.) The NPEG solution seeks to include the ability to adjust both the time delay and the reverse current threshold at which the network protector would open instantaneously.

The adjustment of time delay and instantaneous network protector opening thresholds will be based upon the site specific characteristics of the spot network configuration and equipment (number of NPs, size of transformers, characteristics of the primary network, etc.), the characteristics of the DR (inverter-based vs. rotating machinery, type of disconnecting means, etc.) and the operating policies of the local utility.

Significant factors in the assessment of these parameters include the potential fault current contribution of the type of DR being considered. As noted in the GSA Williams study, in fault scenarios, machine-based generators can, for brief periods of time (on the order of three cycles) contribute as much as ten times their full rated current. This can be compared with the fault characteristics of inverter-based technologies which are on the order of 1.5 to 2 times their full rated current.

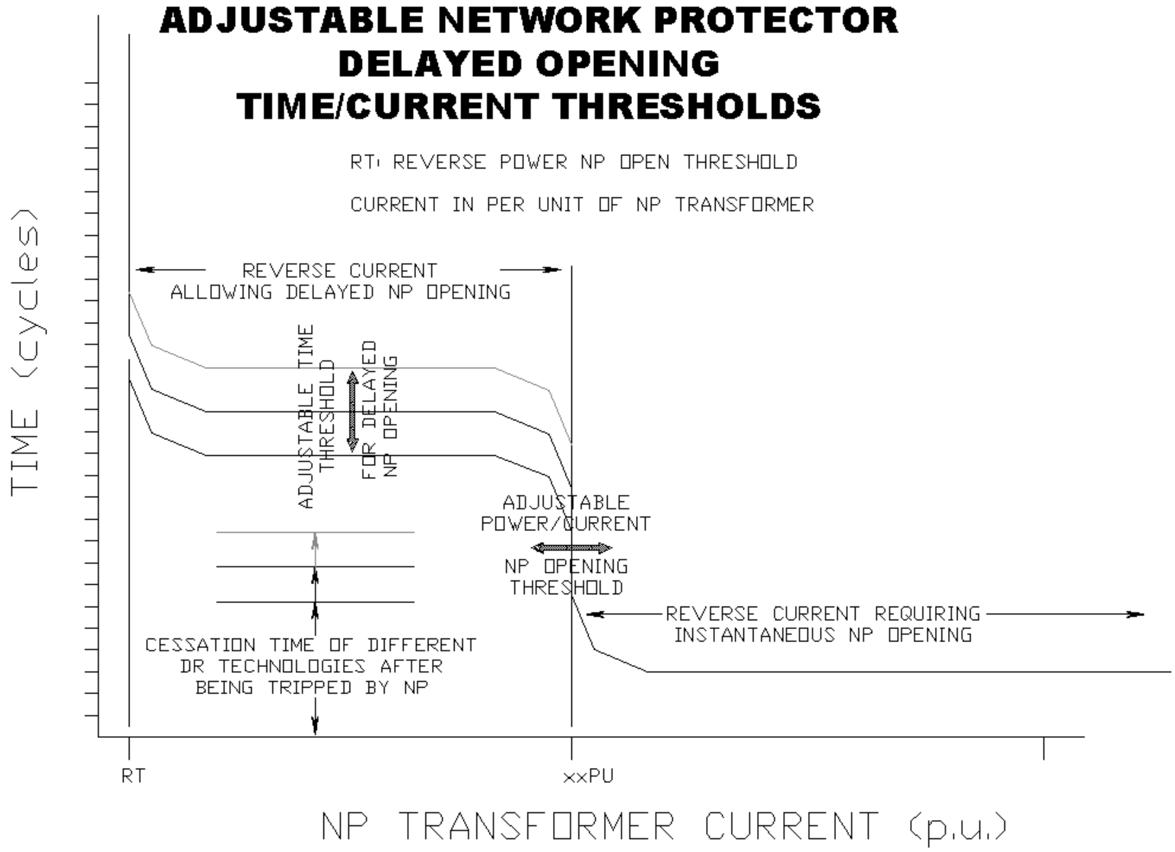

Figure 16: Adjustable network protector time & reverse current parameters to coordinate with NPEG controlled DG

The switching/opening time of disconnecting devices, whether external or integrated into the DR, will also have a major influence on the required delay time. Inverter-based technologies may be able to be shut down in less than a full cycle. Static switches may also be a solution with opening times in the sub-cycle range. Electronic circuit breakers will have different trip times than thermo magnetic breakers, which will have different response times than electro-mechanical contactors. Depending on the switching technology used to trip the DR the latency between the initiation of the trip signal from the network protector controller and the cessation of current contributed by the DR will vary. The technical solution developed under the Network Protector Enabled Generation initiative will need to address, to the greatest extent practical, as many of the characteristics of different DR technologies as possible.

3.1.5 IEEE 1547: 4.1.4.2

IEEE 1547 2003, article 4.1.4.2 requires that, "Connection of the DR to the Area EPS is only permitted if the Area EPS network bus is already energized by more than 50% of the installed network protectors."

In addition to the directional power threshold criteria for tripping the DG by the NPEG Master Control Unit this requirement must also be met. This means that more than 50% of the network must be closed or the NPEG will send a trip signal to the DG, regardless of the direction or level of the power flow at that moment. Under normal forward power conditions this criterion should always be met, however as an added safety measure and in order to explicitly comply with IEEE 1547 4.1.4.2, this binary test should be included in an NPEG control solution.

3.1.6 Control Logic

The operational criteria of IEEE 1547 4.1.4.2 and the thresholds conceived by the NPEG approach can be combined in a simple logic expression that will indicate when the NPEG MCU will send a trip signal to the DG. The paper "Connection of a Distributed Resource to 2-Transformer Spot Network," outlines a preliminary criterion, expressed as an overpower trip setting, P_O, for determining the forward power at the network protector required before allowing the DG source to reconnect. The addition of the forward overpower setting adds hysteresis required to limit potential cycling of the DG source.

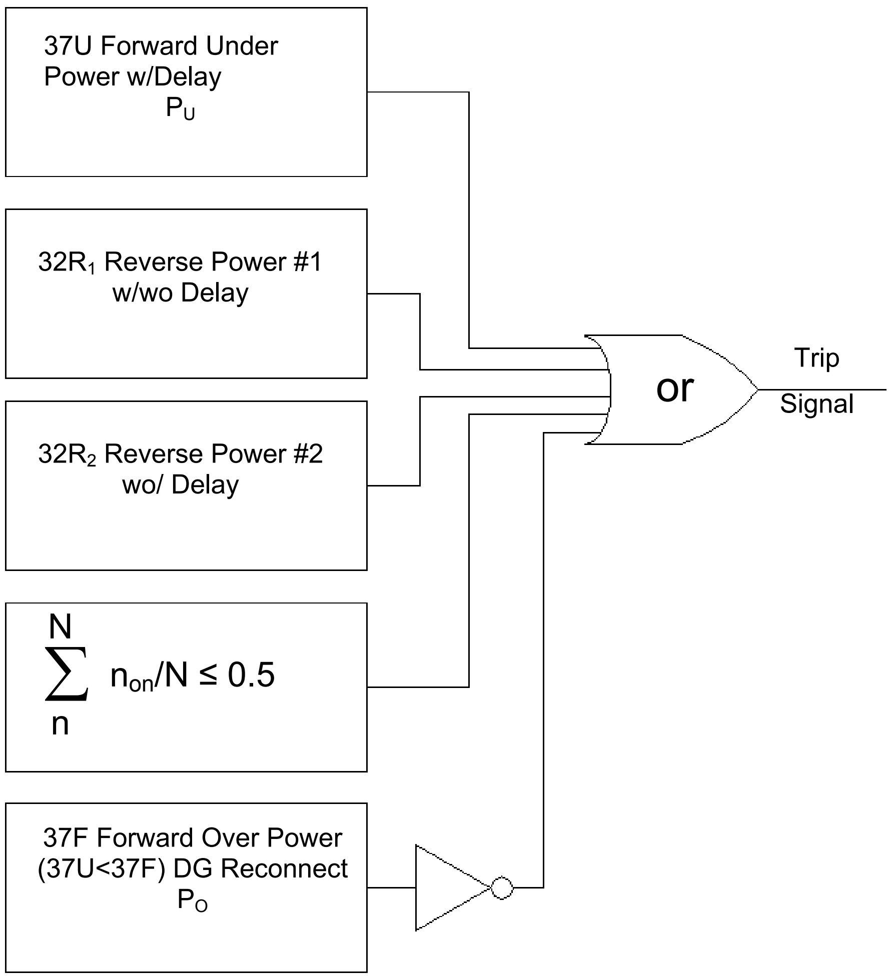

Figure 17: NPEG trip signal logic.

When the NPEG MCU trip signal is sent to the DG the forward overpower will be set low. The signals P_U, RT_1 and possibly RT_2 will remain high until all of the first four of the above conditions are false and the forward overpower threshold, P_O, has been exceeded. This will result in a cessation of the trip signal to the DG permitting it to reconnect. For operational purposes time can be added to all of these criteria. For example, the first criterion could be modified by adding a delay of thirty seconds. This would delay the shut down of the DG due to momentary sags in the demand of the facility which did not result in reverse power flow. The optional delay in the first reverse power threshold, RT_1, might have a maximum value in the range of 15 cycles or a quarter of a second or less. The second reverse power threshold, RT_2, for instantaneous trip would, as the name implies, be instantaneous.

The operational logic of the network protectors themselves is referenced in section 3.1 above. These are operational decisions that are the domain of the utility or distribution company that manages the network. As such, they are outside the scope of a specification for the NPEG concept. However in choosing whether or not to add delay to the network protector operation, and if so how much delay, the utility can choose to accommodate distributed generation by coordinating with the DG while still maintaining quality and continuity of service.

3.2 Supervisory Status Reporting

The NPEG system shall have the ability to continually monitor and report on the status of its constituent components. *[The system is modeled on the type of supervised technology used in intelligent fire alarm systems.]* The supervisory functions of the Master Control Unit (MCU) shall monitor and confirm the open/closed status of the network protectors (NP), the communications link to the network protectors, the DG Interface (DGI), the DG source itself, and the Data Exchange and Control (DEC) link. The status of all of these devices and communications links will then be reported to the enterprise network.[7] The functional specifications of the constituent parts of the supervisory system are:

- the MCU-NP communications protocol;
- the MCU-DGI/DG communications protocol;
- the MCU to enterprise communications protocol.

3.2.1 MCU-NP Protocol

The communications exchange between the MCU and each of the network protectors, aside from any required hand shaking and polling, shall be unidirectional. The MCU shall monitor each NP in a "read-only" manner. The MCU will have no control capability over the network protectors and the NPs will operate independently of the MCU. From an operational perspective, except of the insertion of optional time delay for RT_1, the NPs will behave as they would absent the NPEG system.

[This topic needs to be informed by the network protector manufacturers' current capabilities. If their microprocessor-based models have external I/O the protocols and specifications for the existing equipment should be the first choice. In order for the NPEG system to work the NP processing time and communication speed will have to meet the latency requirements of the overall system.]

The MCU will poll the NP at a user adjustable rate of between 1ms and 2000ms.

[The rate of polling of the NP will be determined by the latency requirements of the system as a whole and by the operational requirements of the utility or distribution company. Coordination for this operational criterion can be met with greater and lesser ease depending upon the physical characteristics of the DG, the communications link and the network protector response time.]

In the ideal embodiment of the NPEG concept the NPs shall report four parameters:

- the NP unique address;

[7] It is understood that some secondary network distribution systems will not have SCADA communications capabilities. Those networks that lack the ability to communicate to the enterprise level will not be able to include these features of the NPEG system. This description is the preferred form of the systems:

- the NP Open/Closed status;
- the NP directional power direction;
- the NP directional power magnitude.

The MCU shall calculate the total magnitudes and directions for use in its operational decision process.

3.2.2 MCU-DGI/DG Protocol

The MCU will poll the DG Interface at a user adjustable rate of between 1ms and 2000ms.

The DGI will be uniquely addressable. The DGI address will be an extension of the address of the DG address.

[The universe of DG devices is vast and heterogeneous. There are a very large number of communications protocols and processor operating systems. The DGI is intended to bridge the hardware/software/communications gaps that will exist. Issue of communications protocol interoperability between the DGI and the DG will have to be resolved on a case-by-case basis. The issue of timing and latency, as it affects the NPEG system as a whole, will also be DG technology specific.]

The MCU will poll the DGI for status and will be able to log three parameters:

- The DGI/DG unique address and the presence of the DG
- The present status of the DG: generating or off-line
- The DG “Ready-to-Trip” status: ready or not ready

The MCU shall be capable of issuing a trip command to the DGI. The DGI shall convert the trip command into the communications protocol of the DG. Once the DG has received the trip command it will initiate the process to cease to energize the output of the DG to the electrical distribution system. When the DG has ceased to energize the electrical distribution system it shall issue an acknowledgement to the DGI indicating that the DG has shut down. The DGI will convert the DG communications protocol to the NPEG protocol and transmit the signal to the MCU.

3.2.3 MCU to Enterprise Communications Protocol

The communication of system status from the MCU to the enterprise level is the least critical of functions to the operations of the NPEG system described here. Some secondary network protector systems may not currently possess mean to convey information in this direction. This information exchange need not even occur in “real time” and could be implemented through a low frequency power line carrier scheme (or even left for implementation at a later date.)

The MCU shall report four conditions to the enterprise level:

- the MCU unique address;
- the DGI Status Normal report;
- the DGI Trouble report (communications to DG failed);
- the DGI Alarm report (NPEG has tripped the DG off line).

4 Material Performance Specifications

This portion of the performance specification is a very preliminary attempt at to address the most material conception of the NPEG system. Currently this section provides only very preliminary guidance for NPEG hardware technology. To date the collaborative process has not had time to permit contribution by stakeholder experts such as network protector manufacturers and utility protection engineers, thus this section lacks the level of detail that would be preferable when approaching a product development program or even an R&D effort. Having made the previous observation, it may well be that many of the very specific component details, such as physical characteristics of devices or communications protocols, are well established in individual utility practices. As has been indicated in the opening sections of this specification, it is the intent of this process to use whatever existing technologies and standards are available and appropriate. The intent of this specification is not to re-invent any technology unnecessarily.

4.1 Master Control Unit (MCU)

The MCU shall be a microprocessor-based controller employing a real time operating system. The clock speed shall be sufficient to allow all necessary detection, processing and response in less time than the required response time of the NP or the DG. The range of operating times shall be determined by evaluating the response times of existing network protectors, DG technologies and disconnection devices such as circuit breakers and contactors.

4.1.1 MCU Physical Characteristics

The physical characteristics that the MCU shall have will include:

• the MCU shall be submersible;
• the MCU shall have an operating temperature range of -40°C to 50°C;
• the MCU shall possess the following communications capabilities ______________________?

4.2 Network Protector (NP)

• The NP shall possess the following communications capabilities/protocols_______________?
• the NP, when polled, shall acknowledge the inquiry with a unique address response and shall report Open/Closed status, directional power direction, and directional power magnitude.

4.3 Distributed Generation Interface (DGI)

• The DGI shall be designed to be lockable and tamper resistant;
• the DGI shall possess communications capabilities that are compatible with the MCU;
• the DGI shall possess communications capabilities compatible with the DG control unit to which it must interface. This may be either an electronic trip mechanism or an electromechanical device.

4.4 Distributed Generation (DG)

Distributed generation technologies and their associated external communications capabilities, where they exist, are extremely diverse. It is an extremely heterogeneous population and as such the interfaces to their control capabilities –if they exist at all-- must be handled on a case basis. In the those cases where no external I/O exists on the DG which will permit remote shut down of the device a separate electromechanical solution or device such as power converter or solid state switch shall be used and it will dictate the interface requirements of the DGI.

4.5 Data Exchange & Control (DEC)

The “Data Exchange & Control” or DEC represents the physical link between the MCU in the utility’s vault and the DGI at the location of the distributed energy resource that is being monitored and controlled[8]. Here the DEC is conceived as an all dielectric fiber optic link. In keeping with the spirit of 1547 4.1.4.2 the specific characteristics of this link should be chosen by the local utility based upon local practices.

4.5.1 Fiber Optic: Cable-in-Conduit

Fiber optic cable shall meet the cable-in-conduit standards of the local utility for pulling bend radius, number of bends, tensile strength, installation procedures and testing. Outside cables will transition to plenum rated cable at a utility-secure junction at or near the point of common coupling.

4.5.2 Fiber Optic: Plenum Cable

Plenum rated cable shall be used for all interior installations. Installed cable shall meet or exceed the local utilities specifications for inside cable.

[8] The use of the term “Data Exchange & Control” is used in an attempt to be consistent with the approach and nomenclature of IEEE 1547.3, “Draft Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems.”

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