Case Study on DG Interconnection for Network Systems:
Project: 595 Market Street, San Francisco, California

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for review and comment by Massachusetts DG Collaborative

I. BACKGROUND

This report presents a sample case study for the interconnection of 1 MW of synchronous generator capacity to a secondary spot network located on Pacific Gas & Electric's (PG&E) electric distribution system. The generator provides electric and thermal energy as a combined heat and power (CHP) system to a building located on 595 Market Street in San Francisco, California. Real Energy, Inc. of Woodland Hills, California built, owns and operates the generator.

Navigant Consulting Inc. (NCI) was retained by the Massachusetts Technology Collaborative (MTC) to investigate distributed generation (DG) applications on electric utility secondary network systems. The first phase of the investigation addressed the development of uniform interconnection standards. On February 24, 2004, the Massachusetts Department of Transportation and Energy (DTE) issued an order that largely adopted the Model Distributed Generation Interconnection Standards and Procedures Tariff prepared under Docket 02-38-B. The model tariff was developed via a collaborative process involving representatives from industry, government, public interest groups, electric utilities and other interested parties and stakeholders. The MTC was a sponsor of the Collaborative, and retained NCI to provide independent technical expertise.

In its Order, the DTE set forth for further investigation and resolution several issues that were not addressed in the Collaborative or for which participating parties could not reach consensus. One is an assessment of the role of DG on utility secondary network systems. Secondary networks systems are located mostly in urban centers such as downtown Boston, and present interconnection challenges and hurdles not encountered in interconnections to less complex radial distribution lines. Accordingly, NCI is investigating the status of DG interconnections on network systems, including case studies of existing or proposed projects in Massachusetts or other states. The selection of the DG case study was based on a range of criterion, each of which is addressed in this report. A list of DG case study criterion is presented in Exhibit 1.

II. DISTRIBUTED GENERATION – INTERCONNECTION TO NETWORK SYSTEMS

Interconnecting DG on network systems raises technical issues and hurdles which, if not resolved, can thwart the development of a robust DG market in urban areas. The Model Interconnection Tariff includes network interconnections, particularly for smaller, inverter-based systems, but does not necessarily address specific interconnection requirements for larger DG (i.e., above 7.5% of the network peak) or rotating machines. Interconnection of DG on grid (as opposed to spot) networks raises greater challenges.

The Institute of Electric and Electronic Engineers (IEEE) has developed an interconnection standard (IEEE Std. 1547). However, the IEEE standard applies solely to radial or spot networks, but deferred on addressing grid interconnections due to the inability to reach consensus on highly complex technical issues. Among other issues is the need to prevent the inadvertent loss of network system load due to the presence of DG. Secondary network systems are designed with several levels of redundancy to ensure a very high level of reliability for critical urban or customer load. Electric utilities consistently have raised concerns regarding the potential for DG to degrade network reliability.

The selection of DG candidates for the sample case study encompassed a range of criterion. The intent is to identify installations that meet the criteria, particularly those that address interconnection requirements in Massachusetts for a range of DG technologies. To identify candidate installations for the case studies, NCI contacted utilities, DG suppliers, government agencies and other DG stakeholders. A list of sample study candidates is listed in **Exhibit 2**. Based on the selection criteria and candidate list, we concluded a sample case study of 595 Market Street would address many of the issues raised above, including solutions successfully employed for an existing installation.

III. 595 MARKET STREET –PROJECT DESCRIPTION

This case study analyzes the interconnection of 1030kW of synchronous generator capacity to a secondary spot network at a commercial office building located on 595 Market Street in San Francisco, California. It includes 2-375kW and 1-280 synchronous generators connected to a single electrical bus serving local building load. The generators are designed to operate in a base load mode and are interconnected in parallel to the local utility, Pacific Gas & Electric (PGE). The system is designed to operate while interconnected to the electric grid to avoid islanding, and attendant potential for out-of-phase generation closing into the utility electric grid.[1] The generator is illustrated in Figure 1.

Figure 1

(*Awaiting photo of DG installation*)

The generators are owned and operated by Real Energy, a project developer that has approximately 50 MW of installed generating capacity interconnected to electric utility grids in the United States.[2] All energy is consumed on site and no electrical energy is exported to PG&E. Total generator output is approximately _ percent of maximum aggregate building demand.[3] The building complex owners purchase power produced by the DG units from Real Energy. The generators operate in a combined heat and power (CHP) mode of operation as they deliver electric and thermal energy to the building.

The project began commercial operation in April 2004. Real Energy first applied for interconnection in January 2003 under PG&E's Electric Rule 21 application procedure. Because the utility and Real Energy initially were unable to agree on technical interconnection requirements, they agreed to seek resolution through negotiation. Ultimately, the parties reached an impasse. Accordingly, on September 15, 2003, Real Energy notified PG&E that it would invoke dispute resolution procedures under Section G.2. Following lengthy mediation that extended to late October, terms of which are described in greater detail in Section V, the parties on December 17, 2003 agreed to resolve the dispute and clarify their respective obligations under an addendum to PG&E's Electric Rule 21 application. The signatory parties also agreed that prior

[1] Electric utility secondary network protectors are not designed to synchronize closing with generator breakers when located on secondary networks. If a network protector were to close while a generator was operating independent of the utility grid, it would experience damage or failure. Real Energy offers as an option its customers open transition transfer switching that would permit the customer to operate in a stand-alone mode, but this option was not chosen, likely due to the very high reliability of PG&E's secondary spot network.

[2] Many of Real Energy's facilities are high efficiency, cogeneration units that provide supplemental steam or hot water to satisfy customer thermal load.

[3] NCI has requested, but not yet received building demand and profile data.

Commission (California Public Utilities Commission) approval of the addendum was not required under Section D.1.h of Rule 21.

There are two other addenda also dated December 17, 2003 under terms similar to 595 Market Street terms for two similar synchronous generators sets installed at other secondary spot networks in San Francisco; each of these installations began operation in late 2003.[4] It is likely terms contained in the addenda also would apply to applicants who may later seek to install similarly sized units on PG&E's spot network. However, these terms are not intended to necessarily apply to grid networks.[5] This provision was specifically cited by PG&E to apply solely to spot networks.

IV. PROJECT HISTORY

Real Energy has been very active in the California distributed generation market. With the adoption of Rule 21, rules that both the utility and applicant must follow are now in place, including provision for dispute resolution. These rules, in part, have been the catalyst for increased DG penetration in California, including those developed by Real Energy. In addition to the 595 Market Street, Real Energy owns and operates 2 other synchronous generators interconnected to spot networks in San Francisco. Real Energy installed a similar synchronous generator arrangement on a spot network in Oakland, California in 2002.[6]

The size of the facility – 1030 kW aggregate capacity – was chosen based on the electric load at the 595 Market Street complex and its thermal load requirements. The project also was eligible for State of California funding incentives, which has a 1 MW cap.[7] Project eligibility is based on its designation as a CHP facility. Project benefits are twofold: first, the host customer pays a lower electric bill by virtue of lower energy production cost from the synchronous generators; second, the customer receives thermal energy, which when combined with electric output, considerably raises total output efficiency. Total generator design output efficiency is __ percent.[8]

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[4] The other synchronous generator applications include a 1200 kW facility (6-200 kW units) at 50 Beale Street and an 800 kW facility (4-200 kW units) at 199 Fremont Street.

[5] Grid networks are sometimes referred to as area or multi-block networks.

[6] This facility was installed prior to current Rule 21 application requirements and was not subject to the same level of review and mitigation outlined in the December 17 addendum.

[7] Energy consumed by the synchronous generator lowers the net rating of the 3 units to below 1000kW.

[8] NCI has requested, but not yet received generator efficiency data.

The length of time between the original application submitted in January 2003 and the signing of the addendum occurred 11 months later. The total time from the filing of the application to commercial operation was approximately 15 months. The mediation process included several meetings and much negotiation among the parties. Due to the highly complex nature of electric utility secondary networks and range of technical issues raised, the developer and PG&E retained independent experts to address these issues and propose solutions.

Although the project is on line, provisions outlined in the addendum makes the developer responsible for additional system upgrades if PG&E later determines the generators are causing network protectors to open. Further, costs for PG&E upgrades have not yet been fully reconciled. The potential for these and other prospective costs to increase may cause the project to longer provide net economic benefits. This could lead to either party to invoke dispute resolution for remedies.

V. INTERCONNECTION ARRANGEMENT

Figure 2 illustrates the interconnection arrangement with PG&E. The PG&E spot network includes 4-1500 kVA transformers served by 4-34.5kV underground cables. Each of the transformers includes a network protector equipped with relays designed to isolate the transformer and primary cable under reverse power conditions. The reverse power relays typically are set to trip in 3 to 5 cycles, which is considered instantaneous, for very low reverse power flows, sometimes as low as a few amps. The arrangement presented in Figure _ is typical of electric utility spot networks throughout the U.S.[9]

Figure 2 - Simplified Electric One-Line Diagram

Copy has been requested)

The primary modifications made to equipment owned by PG&E were related to protection and control systems. One of the key concerns raised by PG&E is the potential for inadvertent network protector operation due to the presence of DG,

[9] The voltage rating of PG&E's primary distribution cables (34.5kV) is higher than many other utilities, whose primary distribution systems are typically rated 12.47 kV or 13.8 kV. The higher rated cables sometimes pose additional protection issues when used to supply secondary networks due to higher available fault currents. However, the installation of DG on the spot network serving 595 Market Street did not require utility system modifications that otherwise would not be required for lower voltage primary systems.

thereby degrading the reliability inherent in secondary network systems. This concern is shared by many other utilities with secondary network systems.

To minimize the possibility of inadvertent protector operations, PG&E required and Real Energy agreed to the following systems and control upgrades, each of which are described in the Addendum. PG&E specified in the Addendum that the Producer (Real Energy) would be responsible for the cost of these systems (**O&M too?)**

a. **Replacement of existing instantaneous protector relays with MPCV time delay relays –** PG&E offered Real Energy the option of replacing existing network protector with Cutler Hammer CM52 devices, or replace the relays on existing protectors with MPCV relays or similar PG&E-approved relays with two set points, one with a time delay. Real Energy chose the latter option.

b. **Installation of PG&E-approved synch check relays to supervise synchronization of the synchronous generator**

c. **Installation of PG&E batteries and charging system –** The battery must comply with technical specifications contained in PG&E's Interconnection Handbook and Rule 21.

d. **Installation of a Programmable Logic Controller (PLC)** – The PLC is used to monitor on a real time basis protector and synchronous generator output and abnormal events in order to assure safe and reliable operation. The PLC must be located in the customer's transformer vault, with rigid conduit to network protectors. The network protector must have a contact that provides open/close status to enable PLC monitoring of protector status for generator tripping.

e. **Reverse Power or PG&E-Approved Underpower Relays** – To trip the breaker when total imports drop below the minimum threshold (See below).

In conjunction with the above improvements, the Addendum includes a series of attendant operating procedures and rules, including monitoring requirements and periodic reporting. Further, the results of the monitoring program could yield information that could obligate the owner to install additional equipment or to comply with additional operating rules or mode of operation if PG&E later determines spot network reliability or performance is degraded due to generator operation.

- The generator breakers must be opened if the total imported power through the network protectors is less that 10 percent of the aggregate rating of the network transformers; or 600kW (which is 10 percent of the aggregate rating of the 4 network transformers). This percentage was selected to ensure individual protector would successfully reclose following an operation.[10]

- No more than one protector may be open at any time. Thus, if only 2 of the 4 protectors are open, then the generator breaker must stay open until at least one of the protectors successfully closes.

- Generator breakers must open with 90 seconds under non-fault conditions; for example, if the 2 or more protectors are open for any reason.

- Generator breakers must open without any intentional time delay under fault conditions or when aggregate imports are below the 10 percent threshold.

- PG&E will monitor network operations and produce reports 30 days, 6 months and 18 months following commercial operation. Such reports will include the following monitoring data:

    1) Building name

    2) Network protector data and identification, including current counter readings, and dates of prior counter readings

    3) Identification and likely causes of protector operations, including notification to the producer within 15 days if the cause is determined be related to the generator(s).

Real Energy is required under the last provision to provide real-time generator monitoring during network operations, including periodic reports of such operations. Further, they are required to identify causes for the operation when PG&E determines it was caused by opened as a result of generator operations.

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[10] Network protector master relays will reclose only if the voltage angle between the primary and secondary side of the protector is less than the set point and power flows are positive. Such conditions may not be achieved if power flows into the network are low as a function of transformer rating.

VI. PROJECT PERFORMANCE

The generators have performed well since they were installed in April 2004. The developer reports that PLC readings indicate there have been no instances where network protectors have operated under reverse power due to DG operations, nor has there been any apparent degradation in power quality. There apparently was a single instance of a relay failure that caused a protector to trip open; the relay has since been replaced. The event did not cause any disruption in service or unserved building load, nor did it cause a lengthy interruption in generation output. There also do appear any primary cable faults – a relatively uncommon event – that would test the relays for reverse power under fault conditions.

The generators generally do not operate during evening hours due to light building loads and price of off-peak power. The developer reports the generators are expected to operate 4000 to 5000 per year during peak daytime and early evening hours. There is no evidence the units have tripped off line due to imports falling below the 10 percent set point for the MPCV relays. Thus, insufficient data exist at this time to fully assess MPCV relay performance, including the need to adjust time delay settings.[11]

At this time, NCI is not aware of any upgrades that the utility proposes beyond those included in the addendum. A PG&E report outlining protection system and unit performance has been prepared for the first 30 days of operation, as required under the addendum.[12] Information from additional reports that will be submitted after 6 and 18 months should yield important performance information on the need for future changes to protective systems or operating modes and procedures.

VII. STANDARDS

The following standards or guidelines apply to the interconnection of synchronous generators at 595 Market Street.

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[11] The MPCV relays and time delay settings are similar to a General Services Administration project located in the Williams building in downtown Boston. The Williams building includes an induction generator and PV panel, which are designed to trip off line on time delay under non-fault conditions similar to 595 Market Street. These units have been operating for about 2 years and the GSA reports these relays generally have operated as intended.

[12] NCI has requested a copy of the report

- IEEE P1547 Standard for Interconnecting Distributed Resources With Electric Power Systems

- IEEE Standard Requirements for Secondary Network Protectors (IEEE Std. C57.12.44-2000)

- IEEE Guide for the Protection of Network Transformers (IEEE Std, C37.108-2002)

- PG&E Electric Rule 21

The generators and interconnection arrangements appear to have met requirements and guidelines outlined in each of the above documents. In particular, the requirement that no more than 1 network protection may be open for the generator breaker to remain open is consistent with Section 4.1 of P1547. Also, PG&E Electric Rule 21 includes an addendum that outlines additional requirements to or clarifications of Rule 21 for this sample case study.

VIII. SUMMARY

Although the units at 595 Market Street recently began operation, there are several findings and lessons learned that likely will apply to DG installations in other states and that may need to be addressed in the Massachusetts interconnection tariffs.

1) Application Process

The length of time between the filing of the original application to the project start date was over 1 year, driven in large part by negotiations for the interconnection requirements and the decision to invoke dispute resolution. The time to from application to commercialization may have been influenced by the absence of an industry standard or practices for import thresholds and network protector relaying and controls. Experience gained from the processes followed or adopted for 595 Market Street may be useful in developing such a standard or guidelines applicable to Massachusetts.

2) Interconnection Costs

The initial application fee under PG&E was $7500. Considerably greater sums were spent for dispute resolution and the cost of requisite upgrades, and the developer may be subject to additional costs related to the interconnection. Total interconnection costs for the interconnection has exceeded $100/kW. For smaller sized units, many of the cost of these upgrades likely will apply as well. For example, the replacement of the network protector relays and the programmable logic controller are independent of DG size.

3) Technology

The size of the DG application, 1030kW is relatively large compared to other DG installations in the U.S. Synchronous generators also have the most significant potential impact on a secondary network system (for similarly sized units). Notably, the developer and utility ultimately were able to reach consensus on a technical solution. The size and type of DG technology at 595 Market Street, and at demonstrates that based on performance thus far, synchronous DG applications up to 1 MW are technically feasible on spot networks. There may be different minimum technical and operating requirements that would apply for smaller or inverter-based DG applications, such as PV and fuel cells. One of the key issues that may require resolution is the minimum import threshold for generator tripping. The 10 percent level included in the addendum was achieved by negotiation and involved compromise by both parties. Additional study may be needed to confirm an appropriate threshold.

4) Reliability and Performance

To date, the generator has operated as intended and there have not been any instances of protectors tripping under reverse power due to the generator. There was one instance where a relay failed, but which subsequently repaired. However, the unit has been on line for only a few months and we expect additional operating data and information will be available over time. For example, PG&E will issue reports based on PLC readings 30 days, 6 months and 18 months following unit start-up. These reports should yield important data on network protector and protection performance, including the need for subsequent upgrades.[13]

[13] NCI has requested a copy of the 30-Day report.

IX. FINDINGS AND CONCLUSIONS (to be completed)

a. Interconnection Performance
b. Issues Addressed in Current DTE Tariff
c. Suggested Revisions to Tariff Based on Case Study Results
d. Interconnection Guidelines – IEEE and State
e. Areas and Issues Needing Additional Study
f. Next Steps

<u>Exhibit 1: DG Network Case Studies: Selection Criteria</u>

1. **General**
   - **Location - Urban versus Suburban –** Preferably, one from each
   - **Application Type –** One "Simplified" or "Expedited," the other "Standard" or equivalent
   - **Jurisdiction –** one in Massachusetts, one in state w/ significant DG penetration (e.g., California or New York); none FERC wholesale
   - **Owner(s) –** one government/public, the other private or utility-owned
   - **Funding –** One fully private; the other subsidized (e.g., by supplier)
   - **Interconnection Standards –** one in state w/ approved standards; the other proposed or not yet in place
   - **Export Sales** – None expected, except Net Metering for DG <60kW
   - **Residential/Commercial –** preferably, one of each (Commercial default); residential application on network likely difficult to locate

2. **Interconnection Arrangements**
   - **Spot versus Grid Network** – Preferably, one on grid, one on spot
   - **Transformers/protectors** - If Spot Network, 3 or more devices; if Grid Network, four primary feeder minimum
   - **Protection (Network Protectors - NWP)** - one with time-delay, one instantaneous setting
   - **Loads** – One <15% of NWP composite load; the other >15%
   - **Primary System Upgrades** – one w/ required T&D system upgrades; the other integrated w/ no major T&D upgrades
   - **SCADA/Communications/Monitoring** – one system output monitored by SCADA or other real-time utility-compliant system; the other, no direct monitoring

3. **Technology**
   - **Size** – One small (<25kW); one large (75kW or greater); could be in combination at one location
   - **Standards** – Must meet UL 1741, IEEE 1547, IEEE C37.108 and IEEE 929, where applicable
   - **DG/Utility Interface** – one inverter-based, one a rotating machine
   - **Type** – Inverter: Fuel cell, PV, wind or capstone. Rotating: any induction or synchronous, including microturbines
   - **Commercial Status/Market Penetration –** one commercially available, one a prototype

Exhibit 2: Case Study – Candidate Sites

	Project Name/Location	City	Utility	Network	Developer/Owner	On-Line Date	kW	Project Description
1	Coast Guard - Williams Building	Boston	NSTAR	Spot	General Services Admin.	2000	105	30 KW PV, 75 KW Tecogen
2	4 Times Square	New York City	ConEd	Spot	Durst, NYSERDA	2000	415	400 kW Fuel Cell, 15 kW PV
3	Eilba Harris Building	Oakland, California	PG&E	Spot	Real Energy	2002	1000	Synchronous Machine (CHP)
4	Moscone Convention Center	San Francisco	PG&E	4kV Spot	City of San Francisco	10/2003	675	2 PV units (469 & 207 kW)
5	50 Beale St.	San Francisco	PG&E	Spot	Real Energy	11/2003	1200	Synchronous Machine (CHP)
6	199 Freemont St.	San Francisco	PG&E	Spot	Real Energy	11/2003	800	Synchronous Machine (CHP)
7	595 Market St.	San Francisco	PG&E	Spot	Real Energy	04/2004	1030	Synchronous Machine (CHP)
8	1 Market Place	San Francisco	PG&E	Spot	Northern Power Systems	1Q 2003	1000	Synchronous Machine (CHP)
9	Sheraton Hotel Towers	New York City	ConEd	Spot	PP&L	Summer 2004 (est'd)	250	Fuel Cell (FCE)
10	Peak Shaving/Load Control	Detroit	DTE	4kV Spot	DTE	(On Line)	1MW+	1 Synchronous Machine (used to provide distribution system support)
11	Data Processing Centers	Dallas/Fort Worth	Oncor	Spot	Oncor	(On Line)	5 Each > 1MW	5 Synchronous Machines > 1MW (operates in standby mode only)