Attachment C – Symposium on Technical and Business Challenges for DG to Play a Role in T&D Planning

MTC held a Symposium on **Technical and Business Challenges for DG to Play a Role in T&D Planning** on January 25, 2006 from 9 am to 5 pm, at National Grid's Westborough office.

The speakers addressed the 3 technical challenges stated in the draft January 2006 Interim Report from the Distribution Planning Work Group. Read-Ahead-Materials were posted before the meeting.

MORNING SESSION 1: TECHNICAL CHALLENGES FOR DG TO MEET T&D NEEDS.
See slides posted below for some of the speakers:

Charlie Salamone, Cape Power Systems Consulting -- DER As A Utility Resource: Technical Issues

Charlie's presentation showed that an enormous body of technical work has been done by utility planners and technical staff, customers interested in local generation, expert engineering firms and modelers, government agencies and labs, and others. The lessons available from this work speak to

- installation, interconnection, and accommodation of user systems
- modeling, based on various optimization criteria
- effective planning processes
- agendas for pilot projects
- regulatory changes needed to make all parties whole
- dispatching requirements
- charette agendas and preparation.

In our continuing work we should take advantage of this extensive experience base and literature.

Bob Galgano, National Grid -- Transient Performance of Distribution Feeder with DG

Bob reviewed some of the relevant findings discussed in the Navigant report and N.Grid's critiques.

Jan Tierson and Jim Stover, Northern Power -- Critical Load Support (CLS) and Intelligent Integration of Relays and Circuit Breakers

Some of Northern Power's distributed energy installations were described, along with some successful controls for both user-side and utility-side protection.

Marko Rosenfeldt, Beacon Power -- Large-Scale PV-based Battery Dispatchable Power

Beacon described some of the benefits of their line of PV inverters, inertial storage systems, and UPS installations. They believe they have some unique experience and available systems allowing efficient dispatching of local generation, and are looking for a pilot project to demonstrate and test their solutions. They proposed a 250kW module, and a later demonstration of a flywheel/battery system. They have been working on these systems with NYSERDA and in CA.

John Howe, American Superconductor

John proposed that the question before the group be re-phrased: "How can the grid be upgraded to accommodate DG?" He predicted increasing fault currents and other capacity problems, making the strength and flexibility of the grid increasingly important. He pointed out that other networks (e.g., communications) have historically improved more by grid upgrades than by load reductions. He then described some distributed dynamic VARs that are now leveraging large real-power capacity increases in congested areas like SW CT. They are working on a form of rotating synchronous condensers made with superconducting coils, fault-current limiters using coated conductor technology for instantaneous current diversion, transformer and cable improvements, all based on "high temperature" (relatively) superconductivity.

Bill Steeley, EPRI -- Case Studies and Methodologies for Using DER for T&D Support Applications: Results from the EPRI White Paper

Bill mentioned some case studies and analyses gathered from NY, CA, and Detroit, and reiterated EPRI's findings, criteria for DER, and "win-win" potential. He showed some cases where DER did save $ vs. planned upgrades, and reported analyses showing deferral value computation. Slow load growth combined with large capital investment projections is the principal predictor of profitable DER installations.

Susan Richter, Manager Power Generation Systems, Wyeth BioPharma, Andover, MA

Susan presented a customer perspective, in which reliability and power quality trump other criteria in critical manufacturing processes. She described their cogeneration facility at a drug manufacturing facility, including substantial redundancies in both electrical and thermal systems.

SESSION 2: DG COLLABORATIVE UPDATES (FOR FURTHER DISCUSSION AT FEBRUARY 15 PLENARY)

A) Framingham Opportunity: Status Update -- Larry Gelbien and Richard Zbikowski, NSTAR

The Framingham "opportunity" has changed substantially since it was originally proposed by NSTAR. The new Natick Mall expansion and some high-rise residential facilities will add over 8 MW of demand to the Speen St. substation (and its tie to Sudbury). NSTAR has already planned transformer and line upgrades to accommodate the new growth projections. Thus the Framingham Opportunity needs re-evaluation, but only at a high level, for what we can learn. They will propose some additional Navigant work and possibly a substitute "opportunity."

B) Network Interconnection Update: Bill Feero -- potential technical solutions and next steps

Bill provided an update on network interconnectivity. An appendix to IEEE 1547.2 on "system impact" will be written. A "Recommended Practice" on networks will be in 1547.6. He has some ideas on detection and tripping communications, will discuss with relay manufacturers and the generator industry, aiming for a fast-enough system to support DG in network applications.

Northern Power -- Case Study: CHP at 717 Fifth Avenue, NYC (NYSERDA site data)

Cogeneration installations in San Francisco and NYC include some advanced network protections, which were designed in cooperation with the affected utilities. (These appear to be spot networks, however.) With NYSERDA support, Northern Power is working on a true network application, using power converters that can interrupt seamlessly in under 1 ms, and other power quality improvements. These add about 10% to project cost. They can isolate the load, continue to spin, and recover synchronization in under 12 cycles. Northern feels they can accommodate any utility requirements if specified clearly, and expressed interest in working on broadly-acceptable interfaces.

SESSION 3: NEW WIN-WIN BUSINESS MODELS

Fran Cummings, MTC -- Update on STAC project for EPRI DER Partnership (click here for award announcement)

Rich Sedano, Regulatory Assistance Project -- MADRI progress toward new business models and regulatory approaches -- see Selection of recent MADRI options papers

Rich described MADRI activities in metering, interconnection, environmental mitigation, business models, regulation, and FERC relationships. Much of their research and concepts would be candidate material for the June report to DTE. He reported on an adaptation of a BG&E formula to electric utilities, providing for profit and incentives decoupled from the standard revenue drivers. He predicted that Mid-Atlantic regulators will soon start time-sensitive pricing options.

Wrap-Up: Potential Future Planning Activities and Implications for the January 2006 Interim Report (facilitated by Fran Cummings)

The last session of the symposium was a review of the day's events and began with a discussion about the EPRI program for development of DG business models. DOER provided a status report and noted that contract agreements are in progress and an April kick off meeting for this effort was considered to be on track. There was discussion concerning the degree of support for the effort and the process that may be used noting that there should be a lot of valuable information that comes out of the work to help address utility revenue and other economic based issues. Fran suggested we review the presentations provided during the day and determine if there were items that would be useful for inclusion in the report to the DTE.

NSTAR noted that they thought that while the presentations were very informative they felt that there was not any additional information that would be useful for inclusion in the report. There was some consensus that the report is just an interim report and it reports what was studied and what also has yet to be addressed. The suggestion was that we either submit the report as is, noting that technical issues remain to be resolved, or we attempt to address the issues and then submit the report. The group felt that there were no real unsolvable technical issues but only issues that may require additional costs. It was noted that the report is currently written to suggest that there may be technical issues that cannot be solved and this would need to be addressed prior to submitting the report.

A concern was expressed as to how long and what process would be employed to resolve the remaining technical issues. Given this uncertainty it was felt that we should submit the report as a status update to the DTE and then focus on the technical issues on a continuing basis. The MADRI effort was reviewed and it was reported that the scheduled study of the revenue related issue may or may not proceed depending on funding and was expected to be completed in around 3 or 4 months. The DTE report currently has a category B calculation as developed by Navigant that includes a number of cost calculations.

NU noted that they thought that the 3 month Charette effort previously discussed would be a valuable effort to address the technical issues as well as the cost as issues.

The DG suppliers were asked about their take on the issues and they felt that the technology was there to solve most problems noting that there were some larger issues, such as communication architecture and control and command requirements, that utilities would need to address. It was also commented that there are a number of unresolved issues that need to be address that go beyond the technical ones such as adoption rates and impact on utility revenues, which were also significant concerns. There was a comment that some expect that the Charette will address procedural as well as other issues in addition to technical ones. DG supplier comments noted that some of their utility customers are simply taking the process one step at a time, addressing eqach issue as it comes up.

There was a question raised concerning DTE's role in prioritizing DER and the incentives they will be providing in achieving their goals. One response was that DTE is the policy maker and they will establish the process based on the inputs they receive. A key question was whether DER is a distribution deferral value worth pursuing or should the recommendation to the DTE be that other areas for savings be focused upon.

A customer representative noted that customer concerns were focused on their reliability of service rather than the reliability of the system and suggested that it might be better to focus on opportunities to capitalize on when they arise, rather than the general case of developing DG to solve specific distribution problems.

The utility people noted that there was a lack of case studies for customer based systems to know how they would provide support and as such there was reluctance to accept that customer based solutions are technically viable as a utility resource. The DG supplier group asked utilities what it would take to make DG a viable solution. The utility group suggested that there is still uncertainty around how DG would be studied and employed as part of the planning process. If utilities can define what they need the DG suppliers suggested that they would like to work with utilities to help address their concerns.

There was a comment concerning consideration of what the customer needs and wants. The various perspectives on how customer expectations and utility obligations affect each other were reviewed. The other issues to consider include the technologies presented by ASC with respect to optimization opportunities and it was suggested that these might also be included in future investigations.

Fran suggested that the notes from the meeting be circulated and, given acceptance by the group, they could be included in the report submitted to the DTE. The group felt this was a reasonable approach pointing out that the notes should reflect the fact that the symposium was very well attended and that everyone felt there was real value provided for all that attended.

Enercon Engineering Comment Submitted by email Following the Symposium, addressing the 3 technical challenges and offering some examples of projects that address those concerns -- Rick Allison, Chief Engineer, Enercon Engineering, Inc (*see end of document*).

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ENERCON ENGINEERING COMMENT SUBMITTED BY EMAIL FOLLOWING THE SYMPOSIUM

The following addresses the main areas of concern and offers some examples of projects that address those concerns.

Rick Allison
Chief Engineer,
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We offer the following input from our experience as it applies to the three main areas of concern that were discussed. We have designed the controls/switchgear for hundreds of Megawatts of generation on various utility grids, mostly in the range of 5 to 20 Megawatt installations. These installations for the most part perform in parallel in a "load follow" mode when requested by the utility for curtailment during "peak periods". These are both for cooling loads in the summer months and occasionally for heating loads during the winter.

The vast majority of these projects also provide "standby power" to the facilities being served and have the ability to synchronize back to the utility grid after it has been restored following an outage. The projects are often sited at the serving distribution substation with the generator controls being capable of tripping and synchronous closing of the facility feeder breaker(s)/reclosers. Some projects are physically located within the served facility with the same control for the "incoming" normal service breaker(s). The generation may be owned and operated by the facility/customer, or in some cases by a "third party" who recovers their investment from the difference in utility rates provided by the "curtailment contract" with the serving utility and possibly from "standby service" that is provided. In example we offer the following overview of some of the larger sites:

- Project #1: A 16 megawatt installation consisting of 10, 1600Kw, 4160 volt generators, connected to a common 15KV bus via 2 10MVA transformers. The common 15KV bus is in turn connected to the load side of either of two substation feeder breakers to a large manufacturing facility. The connection is via two separate tie breakers and the operations insure that the two utility feeders are never paralleled and that the generators parallel with each in sequence and never at the same time. Interconnection relaying is provided for each of the utility feeder breakers. This project was installed by a third party and is used to reduce the normal facility load of approximately 12-14 megawatts to a curtailment level of 100Kw upon request of the serving utility. The plant is fully automated and can be "dispatched" via the installed SCADA equipment that monitors the site at the owners remote facility.

- Project #2: A 12 megawatt installation consisting of seven (7) 4160 volt generators (unit capacity varies), that parallel (in an operator (local or SCADA) selectable sequence) with 6 substation feeders fed from either of two separate transmission lines via 3 transformers (normally 2 transformers are fed by one of the transmission feeds with the other connected to a second line). The substation feeds to the facility (a large pork processing plant) are by breakers and, on three of the feeds, reclosures. The existing reclosures were modified (addition of controls), which allowed the generator plant to control the opening, synchronous closing and the activation/deactivation of the normal reclosing operations of these devices. Similar reclosing operations of the other feeder breakers is also enabled/disabled by the generator system controls. The common generator bus is connected to the load (facility) side of these six feeders by six separate tie breakers and separate interconnection relaying is provided for each of the three substation transformers with tripping of both of the associated feeders from each transformer. Again this project was installed by a third party and is used to reduce the normal facility load of approximately 9-10 megawatts to a curtailment level of 100Kw upon request of the serving utility. This plant is also fully automated and can be "dispatched" via the installed SCADA equipment that monitors the site at the owners remote facility.

- Project #3: A 24 megawatt installation consisting of 12, 12.47Kv, 2000Kw generators located at a municipal utility transmission/distribution substation that serves a large manufacturing plant and several local "villages". The municipal does not generate except during "peak" loads on their supplier's system, which allows them to avoid the associated higher costs of power during those periods. Additionally, through the use of telemetry metering at some neighboring municipals, they export power to offset the usage at the other substations on the main transmission lines. The station also provides "standby" power to their loads (the manufacturing plant and villages) in the event of a loss of the incoming transmission grid. This capability also allows any of their customer base to operate their distributed generation even if the transmission grid is lost. Again the municipal coop can monitor and control the generating station, either locally at the control switchgear or remotely from their offices via a SCADA interface.

All these projects, and many others of smaller overall capacities, are very similar in their modes of operation. They all provide curtail of the load from the utility on demand, standby to the associated loads in the event of a loss of the utility source, the ability to isolate the loads from the utility for storm/disturbance anticipation or utility maintenance on their system/equipment, and an uninterrupted return to the utility source after an outage or planned isolation. They also serve as examples that provide solutions to the three areas of concern that were being raised/addressed during the conference:

Concern 1, reliability of distributed generation as support for transmission grids. The basic design of these projects as well as smaller ones, is to size the generators so that multiple units are available to serve the connected loads in the event of an outage. Indeed, most use a principal of required plus 1 that provides a level of redundancy in the event that a unit is out of service or should fail during operations. Additionally, most of the systems include provisions to "shed/trip" non-critical loads as another means of maintaining the connected loads within the capacity of the available generation. This same design provides some reserve generation and shedding of non-critical loads when required to reduce/curtail load from the transmission grid. The capacity and design ability to provide "islanded" power when disconnected from the grid and to be capable of synchronous reconnection to the grid eliminates the requirement for grid support upon/during restoration from a fault/disturbance on the grid. The loads served by the generating station would continue to be carried by the distributed generation prior to, during, and following reconnection to the grid as/if required for any load reduction operation.

Concern 2, that the design and/or infrastructure of the existing transmission/distribution system imposes limitations on the type, size and/or ability to interconnect distributed generation to some points of the system. The feasibility increases with the location of the DG closer to the switching source (substation or service entrance point). Additionally, with the telemetry metering that is available and emerging, the ability to offset one or more customers loads at a location that provides for easier interconnection, preferable location of generating equipment, and even potential for a recovered heat consumer that might be other than or only a portion of the power consumer(s).

Concern 3, who will have the control of the generation—the utility/transmission operator or the equipment owner?-- and if not the utility/grid operators, what will give a measure of assurance that the resource will be made available when needed? As advances are made in the area of distributed generation, we will probably see systems that cannot only be monitored by the utility/grid operators, but also via secure communications which will be able to start and stop the systems, as well as adjust the output KW and KVAR (PF) levels.

The most common method to dispatch these assets today is via verbal or e-mail request to the owner/operator or in some cases 3rd party companies which manage multiple sites. With the actual control of the distributed generation by the owner/operator what would insure a high level of compliance to requests to operate by the grid managers? The same bottom line that drives this in existing installations - economics. If you fail to respond to a request to curtail, you often not only lose your savings but are penalized in addition,. These conditions are a part of the contractual agreements that are part of connecting to the grid and have worked exceedingly well for those projects we have been involved with.

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