Urban Grid Monitoring and Distributed Resource Integration

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Abstract
NSTAR has developed plans to enhance the grid monitoring instrumentation on one of its secondary area network grids in downtown Boston, MA. This enhanced monitoring will improve visibility into the operation of the grid and allow the integration of distributed resources to be safely tested. Using state-of-the-art sensor equipment along with a novel, low-cost approach to monitoring conductor current and temperature, NSTAR will greatly improve its understanding of grid status and behavior and allow for proactive maintenance that will improve safety and increase reliability. The grid visibility gained from this effort also offers the promise of increased capability for integration of solar photovoltaics (PV), plug-in hybrids, and battery storage, which has not previously been possible on this type of grid except in a few specifically chosen locations. The results and knowledge gained from this project will be broadly applicable to secondary area network grids in urban areas across the United States, including New York City, Philadelphia, Chicago, and Los Angeles, among others.

1. INTRODUCTION
Integration of distributed resources such as solar photovoltaic (PV) installations or electric vehicle integration and storage—the very resources that are critical to the Smart Grid vision [1][2]—can be problematic in urban areas where existing secondary area networks are designed for only one-way power flow. Due to the nature of these networks, generation input other than input from a utility source can render the existing protective schemes inadequate and can be unsafe for the grid. These secondary area network grids are a feature of many major metropolitan areas in the United States, including Boston, Chicago, New York City, Philadelphia, and Los Angeles.

These grids are highly reliable (99.9% on average), designed with multiple primary feeders through network transformers and into a secondary grid that supplies customer load. These secondary area network grids are necessary to keep reliable energy flowing to densely populated areas, which typically include high concentrations of commercial and residential customers.

However, secondary area network grids were designed for power to flow in only one direction, from the utility substations to the customer premises. Reverse power flow from any generation input other than the utility source can render the existing protective scheme inadequate and unsafe to the grid. Consequently, integration of distributed resources such as solar-PV installations or electric vehicle integration and storage—the very resources that are critical to the Smart Grid vision—can be problematic in these urban areas. Experimenting even on a small scale with integrating these resources without appropriate monitoring and controls could destabilize the local grid and create outages and reliability problems for local customers.

Integrating distributed resources into secondary area network grids and maintaining the grid’s high reliability requires that the elements in the grid are continuously monitored to ensure proper functioning. To safely experiment with distributed resource integration, it is necessary to have much greater near real-time data on the conditions of the grid in and around the area where distributed resources are being integrated. However, it is difficult to actively monitor the elements, as they are primarily underground and often without good communications pathways for sensors and monitors. Retrofitting with radio communications is often challenging, since an underground manhole environment is
typically quite hostile to radio communications. Additionally, it is expensive and time consuming for personnel to inspect such facilities frequently. Consequently, there is often limited visibility into the operational status of these assets and information can be outdated for large portions of these grids.

An IEEE working group has been examining this problem in the context of the IEEE 1547 standard for several years, but there is still no agreed upon solution [3]. The IEEE 1547 working group is composed of representatives of a wide range of concerned interest groups, including generator manufacturers, utilities, government agencies, and others. NSTAR has been an active participant and has proposed a new approach at the August 2009 IEEE meeting that should allow a greater level of resource integration. However, to do this safely, the monitoring and metering capabilities of this urban grid must be enhanced.

The planned project will allow NSTAR to safely test distributed resource integration virtually anywhere on the urban grid that has these improved monitoring and metering capabilities. Although a small number of utilities have experimented with the integration of solar-PV into secondary area networks, the tests have been limited to individual sites specifically instrumented for the demonstration [4]. Generally, utilities have not attempted to allow distributed resource interconnections on the secondary area network without restricting the installations to very specific and narrow locations. The results and knowledge gained from the monitoring and testing approach discussed here should be broadly applicable to secondary area network grids in urban areas across the United States.

2. PROJECT DESCRIPTION

NSTAR operates 12 secondary area network grids in downtown Boston, with grid points covered by approximately 4,600 manholes across the metro area. The planned project will deploy additional sensors and monitoring instrumentation on one of these grids in Boston. The specific grid selected is shown in red on Figure 2-1 below and will cover approximately 500 manholes with grid points in a layered instrumentation approach. NSTAR has selected this grid based on the suitable mix of commercial and residential customers, as well as the location of recent demand for PV-type solar installations.

![Figure 2-1. Demonstration Location (grid shown in red) in Downtown Boston, MA](image-url)
2.1. Layered Functionality

The architecture can best be understood in terms of layers of functionality, as illustrated in Figure 2-2. Starting with the lower layers first, various types of instrumentation will be deployed at grid points within manholes throughout the distribution network. Basic, relatively inexpensive, instruments will be deployed at “minor-nodes” in the grid, and more expensive instruments with near real-time monitoring will be deployed at “major-nodes,” as discussed below. Next, customer metering devices will be installed at customer-owned solar-PV installations to monitor specific customer interface points. Monitoring will also be deployed at distribution feeders via an enhanced substation SCADA network to monitor the supply side of the power flow onto the distribution grid.

This additional instrumentation will provide enhanced information that will be made available to other analysis applications over the internal, secure network. The data will be used to improve on-line engineering analysis, and it will provide unprecedented visibility and operational status awareness, as well as a much more accurate asset inventory.

Finally, this improved distribution network instrumentation and monitoring will enable additional and new customer facing applications as shown in Figure 2-2.

![Figure 2-2. Layers of functionality provide the data collection, monitoring, and analysis required for distributed resource integration](image)

The layers shown by the vertical arrows at the left side of Figure 2-2 are described in detail in the subsections below, starting with the Distribution Network layers and moving to the Customer Applications layer.

2.1.1. Distribution Network

The distribution network instrumentation and data collection is described below. Heading letters correspond to the letter labels in Figure 2-2 above for easier reference.

A. Underground (“manhole”) Instrumentation: Within the urban grid NSTAR selected for this project, approximately 500 grid-points inside manholes will be instrumented as a monitoring node. Each monitoring node will be classified as a major-node or a minor-node. Those nodes located in manholes closest to the network transformers (grid supply sources) and power exchanges (multiple connection points in the grid) have current limiters that serve high density loads and are considered “major” nodes. Those nodes serving the remainder of the load, which are in manholes located on the secondary lines between the customers and the major-nodes, are considered “minor” nodes. There are approximately 250 “major” nodes and 250 “minor” nodes in the proposed grid.

1. Minor-Nodes: The Minor-Node instrumentation will leverage a unique and low-cost approach to monitoring underground grid points, and this project will test the viability of this approach. NSTAR has worked to develop the approach and is committed to pursuing a path that leverages flexible, standards-based interconnectivity, should the approach prove successful.

Minor-nodes will be instrumented to detect high and low current, voltage, and cable temperature threshold values on individual secondary-main cables within a grid point. These nodes will be equipped with an AMR/ERT type radio transmitter that allows drive-by collection of this information. The sensors will monitor current and temperature data continuously from the secondary cables in the manholes. The output from the sensors will be collected in a waterproof communication box located inside the manholes. When the current and/or temperature threshold is exceeded, the communication equipment in the box will transmit signals that will be received by drive-by trucks equipped with receivers. Based on the information collected by the receiver, additional actions will be undertaken to remedy the problem. Presently, there is no low-cost means to determine if or when underground secondary main cables on a particular grid are “broken” (open) or overloaded due to an “open limiter.” Since utilities cannot remotely monitor these secondary limiters, when enough of them incorrectly become “open,” the remaining secondary mains and their limiters start to become overloaded and can cause an increased risk of fire or wide area power outages, which necessitate shutting down the network grid to make repairs. The installation of the monitors near the limiter in the manhole will detect when the limiter is open or becoming overloaded, thereby improving the performance of the grid.

2. Major-Nodes: will be instrumented with existing DigitalGrid, Inc. technology, which provides current sensing on a real-time basis [10]. These nodes are also equipped with power line carrier technology that allows near real-time monitoring at the operations center. Once installed, the instruments will be able to monitor the secondary mains current on a real-time basis and provide...
information remotely on the status of the grid. Based on the information received, the system operators will be able to take appropriate actions to remedy any unusual event, thereby improving the performance level of the grid.

B. kWh AMI Metering Deployment: kWh AMI capable meters will be deployed at all customer locations on the local grid where the solar-PV is located. These meters will allow monitoring of the net power consumption by customers. This information can be correlated and analyzed with the information from the enhanced instrumentation to begin to provide a highly accurate picture of that section of the grid. These meters will also provide critical information needed to monitor, control, and ensure the safety of solar-PV integrated resources that are linked to the grid.

C. Feeder Data Metering using Enhanced Substation SCADA: Monitoring of the feeders that supply this grid will be enhanced to better understand the operating parameters as the energy leaves the substation onto the grid. The existing remote terminal units (RTU) in the substations will be upgraded to include programmable logic controllers (PLC) to store network feeder information, analyze data continuously, and take actions when necessary. The new monitoring method will gather phase voltage and phase currents on all three phases. This will help the system operator take corrective actions when required. Two substations will need to be outfitted with the advanced RTUs.

D. Engineering Analysis Data: The information from the sensors, kWh AMI meters, and SCADA data will be sent to a repository, which is implemented on a collection server. The load parameters will be analyzed and appropriate actions taken to safely operate the secondary area network. This will improve overall understanding of the system dynamics and planning of the network grid. The accuracy of the engineering analysis and modeling will enable system reinforcement, when necessary, by adding secondary mains, which will improve the performance of the grid. In addition, some portion of this information will be forwarded to SCADA, including alarm points, and to the Plant Information (PI) system, which is an NSTAR client-server database system that provides information from field instrumentation to appropriate desktop computers throughout the organization. This will make it possible for multiple functional organizations, including Engineering, Planning, Dispatch, etc. to use this data for improving planning and operations.

2.1.2. Customer Applications

New customer applications may be made possible by the distribution network monitoring provided above. These applications will need to be tested on the grid to understand their real-time behavior and to ensure safe operation. NSTAR plans to test the first of these applications, solar-PV integration, on a limited scale. These tests will provide an understanding of the operational behavior as well as establish potential limits on density and size of these types of deployments. NSTAR plans to let customer demand drive the installation and specific location of these solar-PV units within the selected secondary area network grid. The numbers below corresponds to those number labels in the “customer applications” section in Figure 2-2.

I. Solar-PV Integration: This application will enable interconnection of solar powered distributed generation on a secondary area network grid. IEEE 1547 supports the introduction of small PV and other inverter-based distributed resources into secondary area networks. The installation of the DG will require advanced area monitoring to provide the system with the required protection for the grid. This application will be deployed with several levels of safeguard, as described below. Extensive testing and characterization of each level will be performed before the next is attempted:

- **Safeguard 1: De minimus**— For the secondary area network, there are potential sites for DG interconnection requiring only minimal evaluation when the rating of the DG is small in comparison to the minimum demand of the facility (e.g., the de minimus concept). One-fifteenth of minimum building equipment load is presumed to be safe (e.g., approximately 65kW based on 1MW minimum customer load). Equipment would be set to not allow reverse energy in excess of this amount. If the DG output is significantly less than the de minimus threshold, only limited considerations need be given to the interconnection study.

- **Safeguard 2: Installation of kWh AMI Meter on the customer premise to monitor and keep solar-PV load <1/15 of building load (daylight load). If the PV load exceeds this limit, the PV will be taken offline for 24 hours, and the appropriate information will be sent to dispatch.**

- **Safeguard 3: Installation of cable sensors on secondary cables inside manholes on local grid points (near the solar-PV) to monitor stability of the grid.**

The project described here will test the proposal recently submitted by NSTAR to IEEE 1547.6. The approach is only proposed for inverter based DG. This is because the fault current contribution of an inverter based unit is usually limited to 1.5 per unit current or less. The goal will be to safely explore the boundaries of the de minimus concept and consensus recommendations that are currently accepted. By characterizing the behavior and performance of this grid under varying conditions and DG behaviors, it is possible that a new set of acceptable limits may be determined for this type of urban renewable and DG integration. It is hoped that the information gained will lead to the ability to safely integrate PV and other DG in similar urban areas across the country.
II. Future Applications Enabled: Additional DG applications could be integrated in the future, leveraging the monitoring infrastructure put in place by this project and the knowledge gained from the above proposed PV application. For example, electric vehicle integration into the grid could be tested using the mechanisms discussed above.

2.2. Topology and Interconnectivity
A topological view of the planned architecture is shown in Figure 2-3 below. The lower right portion of this diagram depicts a portion of the grid (expanded from the map view in the lower left), that has been instrumented. The upper right portion shows a customer premise outfitted with PV that has been interconnected to the customer mains using appropriate metering and safety equipment to prevent excessive reverse power flow. The various dashed and dotted lines show the flow of data from the instrumentation and meter equipment back to the Collection Server within the Remote Data Collection Center at the upper left of the diagram. From the Data Collection Center, grid status elements can be monitored in near-real-time; additional information (non-real-time) is also collected, aggregated, and analyzed to much more fully understand the behavior of the grid. The communications architecture is constructed, to the extent possible, with standard interfaces to provide flexibility and component choice in the future [5][6][7].

![Figure 2-3. Planned Topology](image-url)
Communications mechanisms for each of the key elements in the architecture have been chosen to suit the needs of the specific element and do so at a cost that is acceptable for a deployment level project.

- Major-Node Sensors send real-time analog information to a Collection Server using power-line carrier technology installed on the underground electrical system. The information is then transmitted via Modbus to NSTAR’s SCADA system for cyber security and firewall protection. The SCADA system will then transfer the information to PI, which is the information exchange interface that makes the information available to other departments (with proper access rights). Prior to this project, only data at the feeder and network protector level have been available to operators through PI.

- Minor-Node Sensors communication is performed using an ERT radio signal that will be transmitted locally to a drive-by handheld device. Radio-Frequency (RF) communication from Minor-Nodes is achieved via industry de facto standard 900MHz spread spectrum ERT signal to drive-by trucks that then transfer this information into the Collection Server. The ERT transmission and receiver technology, although not a de jure standard, is licensed under commercial terms to various manufacturers and is available from a variety of sources providing a diversity of suppliers. While this method of communication was designed to keep deployment cost to a minimum, the sensors will also be capable of having other, standards-based communications interfaced to them.

- kWh AMI Smart Metering will be performed via the internet using standards-based IP FTS protocol or Radio-Frequency (RF) communication from the kWh Meter devices to the Operations Center SCADA using the Verizon public network. The communications selected will be based on the requirements at a particular monitoring and control point in the field, providing a great deal of flexibility and interchangeability. In addition to these new interfaces, existing interfaces to the SCADA system, which monitor the Open/Close state of network protectors, will be leveraged; the information collected will also be used in the engineering analysis.

- These radio communication mechanisms deployed in the field often use, and are increasingly migrating to, standards-based protocols at the higher layers, including Distributed Network Protocol (DNP3) over IP or over serial interface.

All the information that is brought back to the collection server will be put in a common format for consumption by other systems (such as PI, discussed above) for engineering analysis and operational planning purposes. The common suite of IP protocols is used for communication between the collection server at the Operation Center and PI System, as well as from the PI System onto the corporate communications network for consumption by various departments. These systems leverage the NERC control framework and fully adhere to NERC CIP 002-009 specifications.

3. DEPLOYMENT METRICS AND KEY QUESTIONS

The metrics shown in Table 3-1 illustrate the penetration levels and scope of the planned project relative to NSTAR’s urban grid as a whole[8].
### Table 3-1: Deployment Metrics

<table>
<thead>
<tr>
<th>Metric</th>
<th>Metric Location*</th>
<th>Current</th>
<th>Post-Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percent of Network Transformer and Protector</td>
<td>Boston’s urban grid</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Percent of Network Feeder Monitoring</td>
<td>Boston’s urban grid</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>Percent of secondary mains with Major-Node or Minor-Node sensors</td>
<td>Boston’s urban grid</td>
<td>&lt;1%</td>
<td>10%</td>
</tr>
<tr>
<td>Percent of secondary mains with Major-Node or Minor-Node sensors</td>
<td>Program grid</td>
<td>&lt;1%</td>
<td>100%</td>
</tr>
<tr>
<td>Percent of secondary mains with Minor-Node sensors</td>
<td>Boston’s urban grid</td>
<td>&lt;1%</td>
<td>5%</td>
</tr>
<tr>
<td>Percent of secondary mains with Minor-Node sensors</td>
<td>Boston’s urban grid</td>
<td>0%</td>
<td>5%</td>
</tr>
<tr>
<td>Percent of remote kWh AMI Metering</td>
<td>Program grid</td>
<td>0%</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Total solar-PV capacity supported by the urban grid as a percent of the total potential capacity</td>
<td>Program grid</td>
<td>0%</td>
<td>2.5% expected</td>
</tr>
</tbody>
</table>

* Metric Location is defined as the following:

- **Boston’s urban grid** = All 12 secondary area network grids in downtown Boston
- **Program grid** = The one secondary area network grid chosen out of Boston’s 12 grids for the project demonstration.

Some of the key questions that will be examined by this project include:

- What percent of load on the program grid comes from participating customers?
- What percent of participating customer load is generated by PV? The load will be profiled and characterized over the course of the project.
- What is the frequency of occurrence of the need to automatically disconnect customer PV due to grid safety/stability concerns?
- How effective and accurate is the Minor-Node sensing equipment at monitoring power flow?
- Will it be effective to use a higher percentage of Minor-Nodes in the future? What were the determining factors driving which type of node (major- or minor-node) should be installed?
- How effective was the data collection methodology? Could the Minor-Node data be captured as anticipated by using the drive-by vehicles? (So far, there have been no issues with the six experimental Major-Nodes in service.)
- How durable is the sensing equipment to withstand weather, etc.? What is the life expectancy of the sensing equipment?
- What were some of the major challenges for installing the nodes (e.g., the need to pump water out of manholes? arranging for police details and finding room for the sensors)?

Answers to these questions will provide valuable information towards the goal of allowing distributed and renewable resources to connect to urban power grids across the United States.

### 4. REFERENCES


Erik Gilbert is a Senior Consultant at Summit Blue Consulting who focuses on Smart Grid technology, strategy, costs-benefits assessment and helping clients with Smart Grid funding strategy. Mr. Gilbert has over 20 years of experience in development and management of networking products and protocols as well as experience in strategic business assessment for technology solutions. In his most recent role, Mr. Gilbert served as Director of Smart-Energy Products for residential energy management system vendor Tendril Networks, Inc., where he defined and executed their hardware roadmap, including in-home energy displays, IP-to-HAN gateways, AMR/ERT-to-ZigBee bridges and other products. Previously, Mr. Gilbert held various management positions at Cisco Systems, Inc., where he built and launched a number of products. He created and drove the company's Managed Broadband Access program, enabling providers to offer billable services over common IP infrastructure. Mr. Gilbert’s other experience includes associate work at the Bay Area venture capital firm Hummer Winblad Venture Partners and several years of technology strategy development with Ernst & Young Management Consulting. Mr. Gilbert holds a BS in Electrical Engineering and Computer Science from the Massachusetts Institute of Technology and an MBA in Marketing from the University of California at Berkeley.

Lawrence Gelbien is Vice President of Engineering at NSTAR Electric and Gas Corporation. NSTAR is an electric and gas utility servicing 1.4 million customers in Massachusetts including the City of Boston. As Vice President of Engineering, Mr. Gelbien is responsible for electric system planning, transmission, substation, and electric distribution design. Mr. Gelbien is presently heading up NSTAR's Smart Grid Program and has done evaluation on electric battery storage technology. Prior to joining NSTAR, Mr. Gelbien worked 21 years at Long Island Lighting Company, an electric and gas utility located on Long Island, New York and which is now presently a National Grid Company. At Long Island Lighting Company, Mr. Gelbien held a number of positions with responsibility for Distributed Generation, Distribution Automation, and System Control and Protection, to name a few. Mr. Gelbien holds three patents in Distribution Automation, which is commonly known as “Grid Self Healing.” Mr. Gelbien has a Masters Degree in Business Administration from Nichols College and a Bachelors Degree in Engineering from New York Institute of Technology.

Robin Maslowski is an Analyst with Summit Blue Consulting with expertise in evaluation of Smart Grid systems, policy assessment for energy efficiency and renewable energy technologies, survey and interview analysis, and end-use metering. She has extensive experience in the evaluation of energy efficiency programs and markets, with particular emphasis on the related costs, expected and realized impacts, and available technologies. Prior to joining Summit Blue, Ms. Maslowski worked for the Utah Energy Office, the Environmental Protection Agency, and Synapse Energy Economics, where she ran and interpreted electric utility system models from economic planning programs in support of alternative energy resources. Ms. Maslowski is a member of the Association of Energy Services Professionals and the Colorado Renewable Energy Society. She earned a BS in Mechanical Engineering from the Franklin W. Olin College of Engineering in Needham, MA.