MA DPU Grid Modernization Working Group

Questions for Utilities Regarding Grid-Facing Systems

March 18, 2013

Responses Due April 5, 2013

Introduction:

On behalf of the Working Group, several parties -AGO, DOER, and DPU – have coordinated topose questions for the distribution companies in order to gather an inventory of the level of grid facing technologies already on the distribution system. To achieve this goal, we have developed: (1) a set of specific questions, and (2) additional requests and clarifications regarding information which we would like included in the responses.

We encourage the utilities to work together to develop a common format for the response, including a common list of those items to be inventoried.If these questions do not provide enough of a guide for an inventory, or if the utilities need more direction, we can organize an additional meeting or call with the utilities, AGO, DOER, DPU (and whomever else) to work out what items should be on the inventory.

Please usethe common inventory terms in the "Definitions Accompanying MA Grid Mod Taxonomy/Functionality Matrix" and add to that, as needed.

Questions related to Grid Facing Taxonomy Matrix:

1. *For all the "enablers" (i.e., items) listed under the heading "Network Systems," provide the following (in no more than a few sentences each):*
   a) *A brief description (including function and capability) of the system your company has.*
   b) *The year of installation; years of any significant upgrade; current plans for retirement or replacement, and current plans for changes or updates.*
   c) *Depending on applicability for each system (i.e., a company may not need to answer all these for each; the point is to solicit and note any helpful or relevant information for the group), describe:*
      i. *Any characteristics that enable or facilitate grid modernization goals and objectives.*
      ii. *Any characteristics that represent challenges or barriers to grid modernization goals and objectives.*
      iii. *Any additional upgrades necessary to enable or facilitate grid modernization goals and objectives.*

This will vary depending on the goal or objective to be accomplished and functionality to be enabled.

      iv. *Approximate cost estimates for any such upgrades, to the extent they are available.*

Cost information for grid modernizations technologies varies greatly depending the capabilities of the technology and the nature of the application. Providing cost information for this exercise has the potential to lead to inaccurate conclusions.

v. *The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)*

See attachment NSTAR 1 and WMECO 1 for available information.[1]

2. *For all the enablers (i.e., items) listed under the other headings ("Distribution System Automation," "Distributed Resource Integration," "Demand Optimization," "System Hardening," and "Workforce Management"), provide:*

    a) *A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability).*

    b) *The level of deployment of this enabler on your system, to date and planned. In regards to the level of deployment of this enabler on your system, include, as appropriate:*

        i. *The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).*

        ii. *The percentage of the system on which this enabler is currently deployed and expected to be deployed.*

        iii. *The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.*

        iv. *The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)*

    c) *Relevant cost information (e.g., cost per unit, cost per feeder, or the estimated cost to deploy for whole system).*

Cost information for grid modernizations technologies varies greatly depending the capabilities of the technology and the nature of the application. Providing cost information for this exercise has the potential to lead to inaccurate conclusions.

See attachment NSTAR 2 and WMECO 2 for available information.[2]

[1] Please note any future projects identified in NSTAR Electric and WMECO's responses are based on current and known factors. As these factors change or as new factors are identified, the Companies may be required to modify, as appropriate, their future projects to ensure that the project remains the best path forward. It is important for NSTAR Electric and WMECO to maintain flexibility in order to respond to system needs and conditions as they arise.

Additional Requests and Clarifications:

The above questions direct the utilities to look at the taxonomy/functionality matrix, and to provide an inventory of the enablers. However, we recognize that this is not a prescriptive list. As such, we would like to ensure that the inventory includes the following:

1. *How many distribution substations do you have in service and how many of those are automated?*

WMECO has 28 substations serving customers at 13.8 kV or 23 kV. Ten of these substations (36%) have some DSCADA capability.

NSTAR has approximately 200 substations, all our transmission bulk substations have full SCADA control. All our major 23kV and 13kV substations have SCADA control. There are a number of smaller substations, each supplying a small number of customers that do not require SCADA control. Overall NSTAR has SCADA control on 120 of our 200 substations. This accounts for 80% of our customers.

2. *How many capacitor banks do you have in service and how many of those are automated?*

WMECO has 250 capacitor banks on its system. Of the capacitor banks, 110 are manually operated, 77 operate independently in the field in response to VAR or voltage levels and 62 are operated remotely via radio controls. The radio controlled capacitors have only one-way communication capability and are operated remotely based on forecasted load levels; there is no signal back to the remote operator to confirm the capacitor actually turned on or off.

NSTAR has approximately 640 capacitor banks on the system with 485 of those having one way pager radio control. There are an additional 190 fixed or time clock controlled. There are currently 155 sets of voltage regulators on the overhead system.

3. *How many distribution system feeder circuits do you have in service and how many of those are automated?*

    a) *Describe, at a high level (e.g., create categories) the level of automation on the feeders.*

WMECO currently has 120 recloser loop schemes on its system deployed on 78 overhead circuits (approximately 50% of overhead and overhead / underground hybrid circuits

[2] Please note any future projects identified in NSTAR Electric and WMECO's responses are based on current and known factors. As these factors change or as new factors are identified, the Companies may be required to modify, as appropriate, their future projects to ensure that the project remains the best path forward. It is important for NSTAR Electric and WMECO to maintain flexibility in order to respond to system needs and conditions as they arise.

serving customers at 13.8 kV and 23 kV). These loop schemes benefit approximately 53% of customers served by the overhead system.

NSTAR currently has over 1850 remote controlled switches that are used to monitor the system loading and improve loading conditions on the system. Approximately 995 or 63% of the circuits had some level of automation, either the breaker, recloser or line/tie switch. Those circuits supplied approximately 937,000 or 80% of NSTAR's customers.

4. *Please include relevant information regarding:*

    b) *Technologies deployed.*

    c) *ARRA program investments.*

    d) *Percent of feeders covered.*

    e) *Is it cost effective to make similar investment on all feeder circuits? If not, approximately what percent should have additional automation / communication?*

NSTAR is the prime recipient of three DOE ARRA stimulus grants and the sub-recipient to the ISO-NE of a fourth award. The three projects for which NSTAR is a prime recipient are:

1) Grid Self Healing & Efficiency Expansion: Create an "auto restoration" or "self healing" capability on the distribution system, using modern sensing, communications and information processing based on digital technologies.

2) Urban Grid Monitoring & Renewables Integration: Allows for the interconnection of inverter-based distributed generation in a safe manner onto the secondary area network grids.

3) AMR Based Dynamic Pricing: Involves the deployment of advanced technology to enable real-time measurement and two-way communication of energy consumption using existing AMR meters.

The fourth project is in conjunction with ISO-NE. NSTAR has installed Phasor Measurement Units (PMU) in four substations to enable real-time phasor data applications. The project is an essential part of ISO New England's plans for infrastructure development based on the expansion of its PMU-based disturbance detection and monitoring system. This pilot will test the provision of real-time data to ISO NE every 1/60th of a second, rather than once every 10 seconds.

5. *This list should also include appropriate information (e.g., total number of units, level of deployment) of the following:*

    a) *SCADA (supervisory control and data acquisition).*

    b) *Remote terminal units (RTUs).*

    c) *Programmable logic controllers (PLCs).*

These technologies are described in the sections above and corresponding attachments, as applicable.

Row	Enabler	1.a Brief description (including function and capability) of the system your company has;	1.b The year of installation; years of any significant upgrade; current plans for changes/ updates;	1.c.i Any characteristics that enable/ facilitate grid modernization	1.c.ii Any characteristics that represent challenges/ barriers to grid modernization	1.c.v The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
1	Distribution Management System (DMS)/SCADA	**GE GEN4 SCADA/EMS:** - Monitoring and control of Transmission, Subtransmission and **North Distribution** - North Distribution: Approximately 1,100+ Supervisory devices, 60,000+ analog & digital points **GE Powerlink Advantage:** - Monitoring and control of South Distribution - Approximately 750 + Supervisory devices, 40,000 analog & digital points - 80 Auto-Restoration (Grid Self-Healing) schemes	**GE GEN4 SCADA/EMS:** - Initial install (SNC-Lavalin GEN3 SCADA): 1994 - Upgrade to GEN4 SCADA: 2007 - Future: Migrate Transmission/Subtransmission to new system Migrate North Distribution to GE Powerlink Advantage and implement 100 Auto-Restoration schemes **GE Powerlink Advantage:** - Initial install of v3.0: 2005 - Upgrade to v4.3: 2011 - Future: Migrate Distribution to new DSCADA platform	Distribution SCADA allows for remote communications / control	None Latest technology installed	Distribution system
2	Outage Management System (OMS)	**GATOR (Graphical Analysis Tools for Outage Restoration)** Key functions include: - Call-Taker module - Customer Self-Service Outage Reporting (IVR, Web) - Incident/Job Management - Dispatching/Crew Management - Advanced Customer Messaging - Reporting: DPU, MEMA, internal - Permit/Planned Outage Management	CGI PragmaLine v2.03 (original OMS): 2000 GATOR Upgrade (OMS v2.04.04 & new GATOR-GUI): 2003 Many enhancements/improvements installed 2004-2012 Future: Planned OMS Replacement Project 2013-2014	New OMS has an mobile dispatch and damage assessment module		Distribution system
3	NSTAR Geospatial Information System (GIS)	**GIS Editor:** Custom developed ESRI GIS application based on ArcStorm technology to maintain Distribution and Landbase GIS assets **GIS Viewer**: ESRI ArcMap 8.3 corporate viewer with some customization to view all the GIS assets **Transmission Editor:** ArcFM version 9.1 editor to maintain the Transmission GIS assets	**GIS Editor:** v82. North 1990's South 2004 **GIS Viewer**: v8.3 2004 **Transmission Editor:** v9.1 2008 **Future:** - ESRI/ArcFM v10 Upgrade In Progress	N/A	Potentially require data model changes for new device types	Distribution and Transmission
4	NSTAR GIS-OMS Integration	**GATOR-GUI:** Custom developed by ESRI GIS-based application integrated to OMS (landbase, circuits, devices, etc) - Utilized to plot outage calls and create polygons (jobs). - Regularly imports circuit and service point data from GIS.	Implemented as part of GATOR Upgrade: 2003 Future: Planned OMS Replacement Project 2013-2014 GIS Upgrade Project: In Progress	N/A	Potentially require data model changes for new device types	Distribution
5	Billing System (NSTAR)	Billing system including budget billing, payment processor, online real-time updates, processing & inquiries of 36 months of historical account data, generation point for field meter & service orders, commercial deposit processing, internal and external supplier processing, produces & supports reporting for regulatory, finance etc. Produces energy bills, online/hardcopy reporting , field orders, transmits and receives fuel payment and collection agency payments.	Initial version 1991 System is continuously modified as a result of Regulatory Directives and/or business requirements.	N/A	CIS is NSTAR's billing system of record. CIS is comprised of 2.7 million lines of code, 42 databases, 2000 modules, 1300 batch jobs, and 75 interfaces. Enhancements may be lengthy & costly due to an IMS database architecture (IMS = Information Management System), customized system written in COBOL, and testing requirements.	N/A

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6	Metering System	**FCS (Field Collection System)** Key functions include: - Provides route, assignment and data management for handheld and mobile meter data collection for 1.5 million "" meters - Client PC: Running FCS Desktop application for system operations - Mobile Collection: Itron Drive-by AMR devices - Handheld Collections with FC300 Itron units running FCS handheld application - Related Applications: Such as RouteSmart GIS, MV-90 xi, IEE and other utility applications	**FCS (Field Meter Collection)** - Installed Version 2.4 SP2 of FCS to replaced Premierplus4 (P4) application in Q3 2012. Project underway in 2013 to add Route Smart (FCS) interface to provide daily temporary and permanent re-routing on a cycle, meter reading office or territory.	Support AMR based system several options available i.e., IP, Fixed networking drive by	Currently used for AMR based system Electronic ITRON meters with RF ERTS	Distribution system
7		**Route Smart ArcGIS** Key functions include: - Provides route optimization. Utilize geocoding and Centrus to route meters.	**Route Smart ArcGIS** Installed in 2007 and upgraded in Q1 2011. Upgraded to Route Smart for ArcGIS 2010	N/A	N/A	
8		**MV90 (Itron Interval Meter Collection)** Key functions include: - Provides interval meter collection via Modem, Verizon 1XRTT wireless networks for 7000 TOU meters. -Allows for manual field collections via DAP 9800 and via laptops for small population of meters - Provide interval data for Customer and Supplier subscriptions	**MV90** Installed in 2006 -Upgraded to version 2.0 Service Pack 1, in January 2009 -Plans to Upgrade in 2013 to Version 3.0 to provide to support Technology compatibility to Windows 7 and new Day Light Saving vendor enhancements.	N/A	N/A	
9	Meter Data Management System (MDM)	**Lodestar Meter Data Management** Key functions include: - Provides Interval data for ISO Load data management and analysis and - Provides interval data for Customer Supplier Subscriptions	**Lodestar Meter Data Management** Lodestar Server/Client version 1.10 and EIP ver. 1.6 were installed in Q2 2011	N/A	N/A	N/A
10	OMS-AMR/AMI Intergration	N/A	N/A	N/A	N/A	N/A
11	Communications Systems (Fiber, Microwave, Radio, etc..)	Various state-of-the-art communications systems, including, high speed fiber, microwave and digital radio network	All installed with-in the last 3-5 years	Presently being used for grid modernization	None	Distribution and Transmission

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1	Distribution Management System (DMS)/SCADA	**Siemens Spectrum Power TG** - Monitoring and Control of CL&P and WMECO Reclosers and Station Breakers - 2400+ Devices, 280,000+ Analog and Digital Points - All circuits are "self-healing" based upon loop scheme configurations	**Siemens Spectrum Power TG** -Initial Install of v7.3F in service date April 2002 - Upgrade to v7.3H October 2003 - Upgrade to v8.2 Decemeber 2007 (included test 5000RTU's, 650,000 Analog and Digital Points) - Currently upgrading to v9.0	Distribution SCADA allows for remote communications / control	DMS-based functionality available but is not currently installed	Distribution system
2	Outage Management System (OMS)	**Oracle Network Management System** V.1.7.1 SP2 · Call Taking from Customer Information System, IVR, Web, and Offline Backup · Event life-cycle management · System-generated, operator-entered, division global, and district global ERTs · Dispatching / crew management · Restoration callbacks via CIS	Installed April 2004 Upgraded to current version in December of 2007 Future upgrade / replacement slated for 2014	AMI module and interface required for grid modernization	N/A	Distribution system
3	GIS-OMS Integration	Smallworld map extraction .mb file format. OMS import of .mb files via vendor model-build process.	Initial installation April 2004 Upgrade in 2008 Replacement slated for 2014	N/A	Potentially require data model changes for new device types	Distribution and Transmission
4	WMECo Geospatial Information System (GIS)	**GE Smallworld Editor:** GE Core Spatial Technology product used to maintain landbase and electric distribution asset information. **GE SIAS Viewer**: GE Smallworld Internet Application Server provides intranet access to Smallworld data including searching and limited printing facilities, with minor custimozations. **Transmission Editor:** Transmission assets currently not in GIS. **ESRI SilverLight Viewer:** Custom built .NET Silverlight based GIS viewing application that lets the user have a Google Maps type of experience. Developed by EPOCH solutions.	**GE Smallworld Editor:** 3.1 installed in 2002, upgraded to 4.1.1 in 2008. **GE SIAS Viewer**: versioin 4.1.2 installed in 2010 **Transmission Editor:** Future plan is for transmission assets to be pulled into Smallword and maintained via Smallworld editor. ~2013 **ESRI SilverLight Viewer:** version 1.0.1 installed in 2012	N/A	Potentially require data model changes for new device types	
5	Billing System (WMECO)	C2 Application Bill Calculation, Bill Presentment, Customer Inquiry, Customer management, Online services, Orders, Rate management, Receivables and Payment posting, Supplier Mangement	System was implemented in 2008 System is continuously modified as a result of Regulatory Directives and/or business requirements.	Foundation exists to expand components and functionality	Although foundation exists to expand components and functionality,enhancements may be lengthy & costly due to a customized system written in COBOL, and testing requirements.	N/A
6	Metering System	**Fieldnet** (Field Activity Tracking and Scheduling and Meter Reading system) Key functions include: - Provides route, assignment and data management for handheld and mobile meter data collection and service orders - Client PC: Running Fieldnet Desktop application for system operations - Mobile Collection with MC3 Neptune Drive-by AMR devices (WMECO only) - Handheld Collections with DAP Bulverde (Neptune) handhelds running Fieldnet handheld application (Windows CE5) - Route management (Rerouting) - Optical Probe capability for extracting interval data - Exception processing - Same day dispatching - ROAM GIS route optimization and management - Related Applications: PRIMEREAD, POWERTRACK, STORMS, MDM, C2 interface - Installed system services WMECO, CL&P, PSNH (for same day service orders)	**Fieldnet** - Installed Original installation early 1990's - Multiple upgrades and improvements - Current version 4.0.2 was installed in January 2012. - Plan to upgrade to most current version available based on product strategy in 2014 to incorporate: 1) Real time communication between handheld devices and customer information and meter management systems and 2) A more robust route optimization and management system.	N/A	N/A	Distribution system
7		**Prime Read (Interval Meter Collection)** Key functions include: - PrimeRead is an electrical data collection application specifically designed and built for Utilities and end-users. The application works with Smart Metering Devices that register electrical Channels from substations and customers. This information can be collected on a scheduled basis remotely and with an unattended operation. This data if useful for billing, energy balance, operations, maintenance and commercial. - Used to capture 15 minute interval data for WMECO Commercial and Industrial meters.	**Prime Read (Interval Meter Collection)** Install March 05, 2008 - Last Upgrade on PrimeRead Version v7.9 in 2008 - Future plans: move entire meter population to MV90 and retire this application	N/A	N/A	

Row	Enabler	1.a Brief description (including function and capability) of the system your company has:	1.b The year of installation; years of any significant upgrade; current plans for changes/ updates,	1.c.i Any characteristics that enable/ facilitate grid modernization	1.c.ii Any characteristics that represent challenges/ barriers to grid modernization	1.c.v The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
8		**ION Revenue** Key functions include: -ION Enterprise is an interval data collection system. It is used to program meters, create reports, trouble shoot meter issues, present data on the web. It manages energy information from installed metering and control devices and offers comprehensive power quality and reliability analysis.	**ION Revenue** Installed ION Enterprise 5.6 in 2005 - Future plans: move entire meter population to MV90 and retire application.	N/A	N/A	
9	Meter Data Management System (MDM)	**Lodestar Meter Data Management** Key functions include: - Provides meter estimation, validation and reconciliation for WMECO meters - ProvidesMeter Determinants to the Customer Billing System for monthly cycle based and totalized billing - Tightly integrated with Billing and Meter Asset systems to improve data accuracy across each system. - Provides data to Meter Data Warehouse	**Lodestar Meter Data Management (MDM)** Lodestar 1.6 installed in January 2013	Loadstar MDM could be expanded to enable additional functionality but it is not a standalone enabler.	Must be expanded and coupled with a Networked enable head in system. Would need to be expanded to include interval data.	
10		**SerViewCom** Key functions include: gathering 15 minute interval data from IP based and phone home meters and exporting to EVEE data warehouse on a daily basis.	**SerViewCom** Upgrade to version 1.60.7 in 2010 Future plans: move entire meter population to MV90 and retire application	N/A	N/A	
11		**EVEE Meter Data Warehouse** Key functions include: - Provides Interval data warehouse, estimation and validation of Interval Meter data - Provide Meter Determinates to Customer Billing System - Provide Load Analysis data for ISO reporting purposes	**EVEE Meter Data Warehouse** - Installed March 2003 - Server hardware upgrade September 2012	N/A	N/A	
12	OMS-AMR/AMI Intergration	N/A	N/A	N/A	N/A	N/A
13	Communication Systems (Fiber, Microwave, Radio, etc.)	**WMECo Fiber-** the optic ground wire (OPGW) installed at WMECo will utimately create a large OC-3 SONET ring collecting data and bringing it back to E.Springfield where it connects to other fiber rings that go to NH and CT. The WMECo ring is used for SCADA, Relaying, and Substation traffic. **WMECo Mirowave-** an extensive microwave system consisting of OC-3, DS3, 4T1, and unlicensed links that support the mobile radio system and other coporate communincations. **WMECo Mobile Radio-** a multi-channel trunked radio system that can support both mobile radio and DSCADA applications. Although this is primarily for voice there are 157 DSCADA units, mostly reclosers, on this system. **WMECo DSCADA Radios**- a separate IP radio system specifically for DSCADA (4 master sites, 8 remote units to date) that compliments the mobile radio system by off loading some of the RTU data at conjested sites.	**WMECO Fiber-** Mostly built out over the last 8 years and continues to be built as Transmission lines are built or upgraded. **WMECo Microwave-** 90% of the microwave equipment has been installed in the last 8 years. Where appropriate fiber will replace some microwave but low density microwave will always be appropriate for radio sites, spurs, as back up, and as alternate routes. **WMECo Mobile Radio-**installed between 2005-2008. **WMECo DSCADA Radios-**this is all new within the last year.	**WMECO Mobile Radio-** this system covers 95% of WMECo and includes 24 radio sites throughout the state.	**WMECo-**the terrain, sparse suburban population, lack of primary data use frequencies, and antenna height restrictions.	

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
1	**Distribution System Optimization**					
2	Fault Detection, Isolation, Restoration (FDIR)	On the NSTAR system, FDIR functionality in the overhead system is achieved through circuit breakers, reclosers and overhead ASUs (automatic sectionalizing units – remote controlled loadbreak switches.) The ASUs act as line or tie switches and work in conjunction with reclosers or circuit breakers to limit the initial outage and the dispatcher then performs remote switching to further isolate the faulted area. This function is currently being fully automated in many cases through automatic restoration schemes as part of the Grid Self Healing & Efficiciency Expansion ARRA project. In the underground network areas, the network feeders and secondary grid are designed such that no customers experience an outage for a fault on the primary system (network feeders) and very few, if any, customers experience an outage for faults on the secondary system. In the underground non-network areas some of the low voltage (5 kV) circuits have VFIs (vacuum fault interrupters) with or without remote control and indication that open to isolate faulted sections. On the medium voltage (15 kV, 25 kV) circuits, the	There are more than 1850 radio controlled switches on the NSTAR system consisting of more than 1240 overhead switches, 415 reclosers, nearly 110 pad-mounted switches and 85 underground VFI switches. There are currently nearly 80 A/R (auto-restoration loops) in service with 100 more scheduled for 2013. When a fault occurs on one of these loops, an algorithm will produce a solution to restore the unfaulted areas of the system. This solution can either be applied automatically or by operator acknowledgement.	The spreadsheet filed in the Company's annual SQI filing shows that there were 1580 circuits in service at some time during the 2012 calendar year. Approximately 995 or 63% of the circuits had some level of automation, either the breaker, recloser or line/tie switch. Those circuits supplied approximately 937,000 or 80% of the system customers.	80% of customers have automation, or 63% of the circuits. 640 cap banks, 485 pager controlled	Distribution & Substation
3	Automated Feeder Reconfiguation	On the NSTAR system, load monitoring of the system is accomplished by automation system continuously monitoring loads and voltages throughout the system using data from the breakers, reclosers and ASUs. The system will produce an alarm for overcurrents or undervoltages that can trigger remote action by the dispatcher.	The same 1850 radio controlled switches referenced above are used in conjunction with station breakers to correct for overloads.	80% of customers will have some form of automation by year end of 2013		Distribution & Substation
4	Integrated Volt/VAR Control, Conservation Voltage Reduction	On the NSTAR system, power factor and voltage control along the overhead distribution circuits are achieved through dispatchable capacitor banks, fixed or time clock controlled capacitor banks and line voltage regulators. There are two types of dispatchable capacitor banks, radio controlled and pager controlled. All capacitor banks on the 15 kV and 25 kV systems are dispatchable. Eventually all dispatchable banks will be pager controlled. Pager controlled capacitors have voltage overrides such that they will automatically disconnect when they sense high voltage or connect when they sense low voltage. Fixed capacitors are connected to the system at all times. Fixed and time clock controlled banks are small units limited to the low voltage (5 kV) system. Voltage regulators operate automatically to adjust for low or high voltage based on a predetermined bandwidth. The Company does not have a CVR program. In addition to the distribution system installations, the company maintains capacitors and reactors at the transmission system and on the distribution system at the substation level.	There are nearly 640 dispatchable capacitor banks on the system with 485 of those having the pager controls. There are an additional 190 fixed or time clock controlled. There are currently 155 sets of voltage regulators on the overhead system. There are 13 stations on the NSTAR system with reactors at the 115 kV or 345kV (transmission) level and 12 stations with capacitor banks on the transmission level. More of each of these are currently in the planning stage. There are more than 35 bulk or distribution stations with capacitors installed and more in the planning stage.	76% of dispatchable capacitor banks have pager controls (485 of 640)		Transmission, Distribution & Substation
5	Remote Monitoring & Diagnostics (equipment conditions)	Essentially all major equipment is remotely monitored and alarmed via SCADA i.e. Substation transformers, remote controlled switches, communications, etc.. On the NSTAR system, all remote controlled reclosers and ASUs monitor the system by providing voltage, current and power factor.	We are in a very advanced state of remote monitoring. As stated above there are over 1850 remote controlled switches that are used to monitor the system loading and improve loading conditions on the system. In addition, the Company has SCADA monitoring on the major bulk distribution stations including all bulk or network supply stations.	See above for FDIR. 60% of the Company's bulk or distribution stations (including all bulk or network supply stations) have SCADA monitoring.		Transmission, Distribution & Substation
6	Remote Monitoring & Diagnostics (system conditions)	Essentially all major equipment is remotely monitored and alarmed via SCADA i.e. Substation transformers, remote controlled switches, communications, etc.. On the NSTAR system, all remote controlled reclosers and ASUs monitor the system by providing voltage, current and power factor.	We are in a very advanced state of remote monitoring. As stated above there are over 1850 remote controlled switches that are used to monitor the system loading and improve loading conditions on the system. In addition, the Company has SCADA monitoring on the major bulk distribution stations including all bulk or network supply stations.	See above for FDIR. 60% of the Company's bulk or distribution stations (including all bulk or network supply stations) have SCADA monitoring.		Transmission, Distribution & Substation
7	**Distributed Resource Integration**					

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
8	Remote Distributed Generation Disconnect	On the NSTAR system, the remote disconnection of 1MW or larger distributed generation is accomplished with radio controlled source sensing reclosers. The recloser monitors load and voltage and opens on undervoltage upon the loss of the NSTAR feeder to prevent the generators from feeding into the faulted area. Remote indication is accomplished by distributation automation.	There are between 30 and 40 of these installations currently active.			Distribution
9	Voltage Regulation	Prior to interconnecting a distributed generation facility, the Company conducts studies to determine if additional equipment is required on the system to ensure voltage levels remain in the required bandwidth. NSTAR is working with Cooper to evaluate move advanced voltage regulator controls.	DG customers shoud consider using storage devices.	DG customers are presently not being required to install batteries, other states require battary storage devices.		Distribution
10	Load leveling and shifting	At this time, DG developers do not deploy storage to match the output of intermittent distributed generators to the load.				N/A
11	Intentional Islanding (microgrid) control	At this time, NSTAR does not have a program to intentionally island load served solely by a distributed generation source(s). The Company does deploy equipment on the system to ensure large generators do not unintentionally island a portion of the system. In addition, At various locations, DG developers do intentionally island load served solely by a DG source(s)				N/A
12	**Demand Optimization**					
13	Home Area Network Communications Capability	Home Area Network Communications Capabilities are being deployed as part of the NSTAR Smart Energy Pilot to enable two-way communicat to the customer using the Internet.	Approximately 2,700 customers had HAN equipment installed as part of the pilot.	0.25% (consistent with Green Communities Act)		Customer
14	Utility/3rd party DR programs (load control)	Load control is also being tested as part of the NSTAR Smart Energy Pilot. Qualifying customers received a smart Programmable Controllable Thermostat with capabilities to re-program over the Internet, or by receiving a load control signal from NSTAR to temporarily raise by a few degrees during Critical Events in the summer.	There are approximately 320 customers in the Peak Time Rebate group and 310 customers in the Time of Use rate with CPP group.			Customer
15	Time Varying Pricing	On the NSTAR system, there are various time of use rates available for retail customers depending on the billing rate for the former operating Companies. In the Boston Edison Territory, for example, there are two mandatory and two optional rates. Customers supplied with primary voltages of 14 kV and above along with medium and large commercial/industrial customers (monthly demands of 150 kW and higher) are placed on mandatory rates. These rates vary seasonally by time of day for both energy and the determination of billing demand. There is an optional rate for residential customers and another for small non-residential customers. Similar sets of rates are in effect for the Commonwealth Electric and Cambridge Electric customers. See response to Metering Question 2.5 for full details.	5,116 customers total See response to Metering Question 2.5 for full details.	0.5% (1.1M total customers)		Customer
16	Advanced Load Forecasting	Econometric modeling using software: Eviews software version7.				N/A
17	**System Hardening**					
18	Elevated Substations	All new substations will be built to standards that take into consideration risk of flooding and are designed accordingly.				
19	Equipment hardening (submersibles; spacer cables; undergrounding)	Extensive guying of transmission poles, standard use of stronger poles, higher class materials, etc.				
20	Distributed Generation/Storage	Developers responsibility				
21	Vegetation Management	NSTAR's vegetation management includes (1) maintenance trimming (circuits are trimmed every four years); (2) enhanced tree removal; and (3) enhanced tree trimming. In addition we are working with various towns for permission to achieve required tree clearances.				
22	**Workforce Management**					

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
23	Mobile Workforce Management Systems	Service Suite is used to schedule, assign and dispatch orders to the NSTAR Electric meter field technicians. Service Suite optimally assigns and dispatches work to the field, monitors work progress, responds to changing conditions, and measures work performance, all in real time. field personnel use rugged mobile laptops over a wireless data connection via VPN.	N/A	N/A		N/A
24	Mobile GIS Platforms	See Attachment NSTAR 1	N/A	N/A		N/A
25	OMS-ERP-CIS Integration	Most of this integration is of the batch file update variety. Customer records from CIS are combined with the GIS data to form the basis of the OMS/GATOR GUI model. This allows customers to be identified within OMS/GATOR GUI. Outage Calls (including status updates, ERT management) are handled directly in OMS not through a CIS interface. From an ERP perspective, there currently is no real-time integration to WMS, Financials, HR, etc.	N/A	N/A		N/A

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
1	**Distribution System Optimization**					
2	Fault Detection, Isolation, Restoration (FDIR)	On the WMECO system, FDIR capability is currently performed by recloser loop schemes. A recloser loop scheme consists of a sectionalizing recloser (SR) a tie recloser (TR) and sometimes one or more mid-point reclosers (MR). The Company is also in the process of investigating the feasibility of automating gang operated air break switches (GOABS) within a loop scheme to break the circuit down into even smaller segments. For the underground network systems in urban areas, by design, the equipment automatically isolates faults and all customers remain served by other sources of supply. For this exercise, network systems were not considered an enabler for modernization. For non-network underground systems, some customers (e.g. hospitals) have site-specific auto transfer capability. The majority (72%) of non-network underground customers are served by fused loop systems with auto source transfer. This configuration was also not considered an enabler for modernization.	WMECO currently has 120 recloser loop schemes on its system In 2013, WMECO plans to install four new loop schemes and enhance four more with increased sectionalization. This project will involve installing 14 additional reclosers on the overhead system. A similar magnitude of deployment is expected for 2014 through 2017, although some of these devices may be automated air break switches with RTU's as opposed to reclosers. This level of deployment will provide benefit to approximately 4,000 more customers or an additional 2% of customers served by the overhead system per year. All loop schemes operate automatically in response to loss of source voltage.	This covers approximatlye 50% of its overhead 13.8 kV and 23 kV circuits. These loop schemes benefit approximately 53% of customers served by the overhead system.		Distribution
3	Automated Feeder Reconfiguation	At this time, WMECO does not have the capability for its system to automatically reconfigure circuits in response to real time system data.				N/A
4	Integrated Volt/VAR Control, Conservation Voltage Reduction	WMECO manages system voltage with load tap changers on substation transformers and voltage regulators on the overhead distribution system. In addition to tap changers, the Company has 123 voltage regulators on the overhead distribution system. Regulators are deployed primarily on long rural circuits where voltage sags are expected. These devices operate independently in the field and are not automated in the sense that system operators can remotely detect or control voltage levels. WMECO manages voltage within a +/- 5% bandwidth and does not have the capability to conduct a conservation voltage reduction program to remotely detect and manage voltage at all points on the system within a tighter bandwidth. Power factor is managed with the use of capacitor banks. WMECO has 250 capacitor banks on its system. Of the capacitor banks, 110 are manually operated, 77 operate independently in the field in response to VAR or voltage levels and 62 are operated remotely via radio controls. The radio controlled capacitors have only one-way communication capability and are operated remotely based on forecasted load levels; there is no signal back to the remote operator to conf	In addition to tap changers, the Company has 123 voltage regulators on the overhead distribution system. WMECO has 250 capacitor banks on its system. Of the capacitor banks, 110 are manually operated, 77 operate independently in the field in response to VAR or voltage levels and 62 are operated remotely via radio controls.	Volatage regulators and capacitor banks are deployed throughtout the WMECO distribution system.	**Cap Banks: 250 total** 110 (44%) manual 77 (31%) automated 62 (25%) remote operation	Distribution and Substation
5	Remote Monitoring & Diagnostics (equipment conditions)	WMECO has alarms in many substations to alert operators for various abnormal conditions. The Company does not have the capability to remotely sense specific equipment conditions (e.g. oil levels) or diagnose problems. Equipment monitoring and diagnosis is performed on a regular basis by substation electricians and line workers.				N/A
6	Remote Monitoring & Diagnostics (system conditions)	WMECO has deployed DSCADA on its system for remote monitoring and diagnostics of system conditions. The data is transmitted from devices to a systems operations center via a 220 MHz radio system. DSCADA is installed in substations for all new and major reconstruction projects. Substations that have DSCADA have the ability to monitor load (per phase current), status and control of the breaker, and status and control of Hot Line Tags (HLT).	Currently, 68 station circuit breakers have DSCADA. Of these 43 are underground circuits (nearly all underground circuit breakers) and 25 are on overhead circuits (17% of overhead circuit breakers). On the overhead distribution system, there are 143 DSCADA enabled devices on 57 circuits	37% of all 13.8 kV and 23 kV breakers have DSCADA. 40% of overhead 13.8 kV and 23 kV circuits have DSCADA enabled devices.		Distribution and Substation
7	**Distributed Resource Integration**					
8	Remote Distributed Generation Disconenct	WMECO has deployed DSCADA enabled reclosers at the point of interconnection for all large (over 1 MW) distributed generation facilities. These reclosers can be remotely operated to disconnect or reconnect the DG facilities from the WMECO system.				Distribution
9	Voltage Regulation	WMECO manages voltage within a +/- 5% bandwidth as described in the integrated Volt/VAR control section. Prior to interconnecting a distributed generation facility, the Company conducts studies to determine if additional equipment is required on the system to ensure voltage levels remain in the required bandwidth.				Distribution and substation
10	Load leveling and shifting	At this time, WMECO does not deploy storage to match the output of intermittent distributed generators to the load.				N/A
11	Intentional Islanding (microgrid) control	At this time, WMECO does not have a program to intentionally island load served solely by a distributed generation source(s). The Company does deploy equipment on the system to ensure large generators do not unintentionally island a portion of the system.				N/A
12	**Demand Optimization**					
13	Home Area Network Communications Capability	At this time, WMECO does not deploy any home area network communications technology.				N/A
14	Utility/3rd party DR programs (load control)	At this time, WMECO does not currently conduct direct load control programs for its customers. Third party providers may offer these services to customers directly.				N/A

Row	Enabler	2.a A description of the "enabler" (i.e., this may be a device type), if it is helpful to have detail beyond what is on the definitions sheet (e.g., may include detail on function and capability);	2.b.i The total number of units installed (note, the purpose is not to be 100% exact – rounded numbers are sufficient) of each enabler deployed; also, this could be broken down into additional "layers" of technology (such as voltage regulators, capacitor banks, etc.) and total planned over a reasonable timeframe (1-5 years?).	2.b.ii The percentage of the system on which this enabler is currently deployed and expected to be deployed.	2.b.iii The percentage of devices (e.g., capacitor banks, reclosers) which are automated, have remote sensors/ control, etc.	2.b.iv The location of the enabling equipment. (In other words, is it utilized at transmission, distribution line levels, at substations, and/or at customer load?)
15	Time Varying Pricing	The Company offers mandatory TOU rates (Rate T-2 and T-5) for customers whose monthly peak demand is 350 kW and above, and optional TOU rates (Rate T-0 and T-4) for customers whose monthly peak demand is below 350 kW. See response to Metering Question 2.5 for full details.	267 customers total See response to Metering Question 2.5 for full details.	0.1% (210,000 total customers)		N/A
16	Advanced Load Forecasting	WMECO uses traditional load forecasting methods that estimate future peak loads on its system based on historical peak data and does not have the capability to base forecasts on real time system conditions.				N/A
17	**System Hardening**					
18	Elevated Substations	WMECO has not identified any substations where the risk of flooding is sufficient to require a project to elevate equipment. All new substations will be built to standards that take into consideration risk of flooding and are designed accordingly.				
19	Equipment hardening (submersibles; spacer cables; undergrounding)	For new construction, WMECO follows distribution engineering standards that require hardening to various conditions, including wind and ice loading. In addition, the Company currently has a program to futher harden certain areas of its overhead system to improve reliability in storm conditions.				
20	Distributed Generation/Storage?	WMECO has not deployed distributed generation specifically to harden its system				
21	Vegetation Management	The WMECO vegetation management includes (1) maintenance trimming (circuits are trimmed every four years); (2) enhanced tree removal; and (3) enhanced tree trimming				
22	**Workforce Management**					
23	Mobile Workforce Management Systems	Fieldnet is used to schedule, assign and process orders to the WMECO meter field technicians. Fieldnet optimally assigns work to the field which is loaded into the handheld device in the morning. At the end of their shift, completed orders are uploaded from the handheld device to the system when the technician returns to the area work center.	N/A	N/A		N/A
24	Mobile GIS Platforms	See Attachment WMECO 1	N/A	N/A		N/A
25	OMS-ERP-CIS Integration	There is an interface from OMS (via the reporting system) to Work Management to create a follow-up work order if needed. From a CIS perspective, outage calls are taken within the company's CIS system (C2). These are passed to OMS and status updates / Estimated Restoration Times are passed back to C2 for communication to customers.	N/A	N/A		N/A