Thomas R. Teehan
Senior Counsel

July 21, 2009

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Smart Grid Pilot Program Proposal
Docket No. _____

Dear Ms. Massaro:

On behalf of National Grid[1] enclosed please find ten (10) copies of the Company's Smart Grid Pilot Program Proposal. The filing is accompanied by a Motion for Protective Treatment in accordance with Rule 1.2(g) of the Commission's Rules of Practice and Procedure and R.I.G.L. §38-2-2(4)(B). The Company seeks protection from public disclosure of certain confidential, commercially sensitive, proprietary, and security-related aspects of the Smart Grid pilot program. To that end and pursuant to Commission rules, the Company has provided the Commission with one (1) copy of the confidential materials for its review, and has otherwise included redacted copies of the plan.

On June 16, 2009, the Commission ordered the Company to file a proposed Smart Grid plan. The enclosed proposal is submitted in compliance with that Commission order. This proposal is designed to demonstrate the attributes of Smart Grid in a manner, and at a scale, to support the future deployment of these technologies. As the filing describes, with a Smart Grid, customers can exercise greater choices about and control over their energy use, while managers of the electric distribution system and transmission grid will have a powerful new set of tools to improve efficiency, reliability and security. Moreover, the program as described in this filing can compete for and be part of a Company application for funding under the American Recovery and Reinvestment Act of 2009 ("ARRA").

The proposed pilot would involve approximately 10,000 customers in the Newport and Jamestown areas and would also include two feeders in the Portsmouth area that serve existing wind generation assets at customer facilities. This deployment area is recommended for several reasons. There is a wide variety of loading issues associated with the proposed deployment area. Additionally, this area contains aging infrastructure, limited space for system growth, and limited access to adjacent distribution systems. The proposed area also includes existing opportunities with respect to distributed generation and storage resources. Moreover, the area is home to a diverse population of residential and commercial customers whose behavioral characteristics will provide insight into the implications and benefits of this technology.

[1] The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company").

The Smart Grid Pilot Program would provide advanced metering, new customer service offerings, and distribution grid monitoring and control. The program proposal includes the following significant features:

- Interval metering capability
- Alternative rate plans
- Consumption and pricing information through a number of media
- Remote control of thermostats and energy consuming devices
- Monitoring and remote control of distribution system equipment
- Augmentation of outage and restoration management ability
- Clean energy storage enhancements
- Advanced meter data and billing
- Smart Grid Cyber Security
- Education and Outreach

The level of funding outlined in the filing assumes that rates will be set that enable National Grid to recover project costs concurrently with their incurrence and to earn an appropriate return on investment. The Company intends to propose a specific cost recovery mechanism for the pilot proposal and will also recommend alternative tariffs for participating customers. Additionally, under the American Recovery and Reinvestment Act, significant funding is allotted to the Department of Energy's Office of Electric Delivery to support, with up to fifty-fifty matching funds, the implementation of smart grid programs authorized by the Energy Independence and Security Act. National Grid intends to apply for matching funds for this and other Smart Grid Pilot proposals regionally. The filing describes how the sharing of aspects of National Grid's other regional Smart Grid in Massachusetts and/or New York could reduce the overall cost to customers. It is important to recognize that prior state regulatory support or approval will improve the Company's and the host state's chances of obtaining those ARRA funds.

National Grid appreciates the Commission's consideration of its Smart Grid proposal in this docket and looks forward to working cooperatively to obtain funding that benefits Rhode Island and promotes the state's energy vision for the future.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures
cc: Leo Wold, Esq.
Steve Scialabba, Division

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

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Smart Grid Pilot Program

Docket No. _____

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NATIONAL GRID'S REQUEST
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid [1] hereby requests that the Rhode Island Public Utilities Commission ("Commission") provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Commission Rule 1.2(g) and R.I.G.L. § 38-2-2(4)(i)(B). National Grid also hereby requests that, pending entry of that finding, the Commission preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On July 21, 2009, National Grid filed with the Commission its Smart Grid Pilot Program in this docket. This filing included information relative to budgets and marketing costs, equipment specifications, and system security provisions for which National Grid is requesting confidential treatment.

[1] The Narragansett Electric Company d/b/a National Grid ("National Grid or "the Company").

II. LEGAL STANDARD

The Commission's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I.G.L. §38-2-1, *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the Commission falls within one of the designated exceptions to the public records law, the Commission has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I.G.L. §38-2-2(4)(i)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely either (1) to impair the Government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I.2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be

released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

In addition, the Court has held that the agencies making determinations as to the disclosure of information under APRA may apply the balancing test established in Providence Journal v. Kane, 577 A.2d 661 (R.I.1990). Under that balancing test, the Commission may protect information from public disclosure if the benefit of such protection outweighs the public interest inherent in disclosure of information pending before regulatory agencies.

II. BASIS FOR CONFIDENTIALITY

The Company has redacted cost breakdowns provided on pages 17 and 47 of the proposal as well as budgeting information contained in Attachment 4 and Marketing costs contained in Attachment 7. National Grid also seeks protective treatment with respect to Attachment 14, which provides hardware and software specifications, and Attachment 15, which is concerned with cyber security measures. With respect to the budgeting and marketing costs and the hardware and software specifications, the Company seeks protection from public disclosure of the Company's valuation and strategy for contract negotiation with vendors. Moreover, with respect to security protection for the system, the Company seeks confidential protection to protect the reliability and integrity of the system and system information from intrusions by unauthorized third parties.

III. CONCLUSION

Accordingly, the Company requests that the Commission grant protective treatment to those previously identified portions of the Smart Grid Pilot Program filing.

WHEREFORE, the Company respectfully requests that the Commission grant its Motion for Protective Treatment as stated herein.

Respectfully submitted,

NATIONAL GRID

By its attorney,

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National Grid
280 Melrose Street
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(401) 784-7667

Dated: July 21, 2009

The Narragansett Electric Company
d/b/a
National Grid

Smart Grid Pilot Program

Consisting of:

Redacted Smart Grid Proposal and
All Attachments except
Attachments 4, 7, 14 and 15

July 21, 2009

Submitted to:
Rhode Island Public Utilities Commission
R.I.P.U.C. Docket No. _____

Submitted by:

nationalgrid

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I. EXECUTIVE SUMMARY

Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company") believes that the U.S. electricity industry will face significant change over the coming years. There will be a shift from a model in which electricity is generated and controlled centrally, to one in which energy is more dispersed and integrated at a local level taking advantage of renewable energy sources. Additionally, environmental awareness and rising prices will require the energy industry to become increasingly responsive to the need for more timely energy usage and pricing information, more tailored energy options, and greater individual customer control.

National Grid recognizes the challenges and opportunities that the new energy market will pose to its existing network and service platform and in response has undertaken an extensive strategic analysis effort and developed a Smart Grid Vision.

NATIONAL GRID'S SMART GRID VISION

National Grid's vision is to deploy Smart Grid technology in order to optimize the flow of green energy resources, enhance the performance of the electric transmission and distribution grid, and provide customers with the ability to make informed decisions about how they use energy.

A Smart Grid will be the fundamental service platform for future years. It will help towards reducing energy consumption and greenhouse gas emissions. A Smart Grid will drive optimization, improve utilization and efficiencies, and enhance the reliability of National Grid's transmission and distribution infrastructure.

This service platform will provide and act as a catalyst for current green technologies (e.g., wind, energy efficiency, demand response) and the emerging next generation of green technologies (e.g., photovoltaic, energy storage, plug-in hybrid electric vehicles) that National Grid believes are essential to meet societal and customers' future needs.

A Smart Grid will provide customers with <u>choice</u> over how the electricity they use is generated and control over how and when they use energy in their homes and businesses. Through this redefined relationship with National Grid, customers will be able to participate in the power of action and contribute to a sustainable future.

A. Background

On April 6, 2009, The Rhode Island Public Utility Commission ("R.I.P.U.C" or "Commission") opened Docket #4052 - Commission's Review into Smart Grid Pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA), as amended by the federal Energy Independence and Security Act of 2007 (EISA). The Commission opened this docket in response to the provisions to 16 U.S.C. 2621(d). That federal statute provides that each state consider requiring that, prior to undertaking investments in non-advanced grid technologies, electric utilities demonstrate that they considered an investment in a qualified Smart Grid system based on appropriate factors including the following: (1) total cost, (2) cost-effectiveness, (3) improved reliability, (4) security, (5) system performance, and (6) societal benefit.

On May 15, 2009, the Company filed its initial comments on Docket #4052. These comments were offered to provide a description of the Company's activities relating to Smart Grid systems in other states as well as a description of the Smart Grid aspects of the Aquidneck Island pilot program in Rhode Island. The Aquidneck Island pilot program is one component of the Company's System Reliability Procurement Plan – PUC Docket No. 3931 filed on February 29, 2008.

The Company's description of Smart Grid programs it is undertaking in other states was intended to provide information to the Commission to help determine the appropriateness of investing in a qualified smart grid system prior to investing in a non-advanced distribution grid system. The Company's comments also include a description of possible augmentations to overlay onto the current Aquidneck Island pilot program, as well as an outline of the filing deadlines for applications for American Recovery and Reinvestment Act ("ARRA") matching funds, which will be available for Smart Grid pilot programs.

B. The Company's Other Smart Grid Pilots

As outlined in the Company's comments to Docket No. 4052, National Grid to date has submitted two Smart Grid pilot proposals. In Massachusetts, the Company – in response to Section 85 of the Massachusetts Green Communities Act of 2008 – has submitted a proposal for a pilot to include approximately 15,000 customers in the Worcester, Massachusetts area. We are also considering adding a second deployment area in Massachusetts as part of our ARRA Filing, which would add 95,000 customers in Malden, Medford and Melrose. In New York, the Company – in response to a request from the New York Public Service Commission – has submitted a pilot to include approximately 80,000 customers in the Syracuse and Albany regions. In addition to smart technology deployed throughout the distribution grid, the New York pilot as filed would include several Clean Energy Technology Modules.

C. Pilot Objectives

National Grid's Program is designed to demonstrate that a Smart Grid deployment may provide significant benefits to customers and society by enabling more efficient energy consumption that results in reduced energy usage, better energy quality, improved reliability, and a general reduction in the carbon emissions required to produce and deliver electricity to customers. Additionally, we hope to demonstrate how significant Clean Energy technologies can be included, in particular storage of wind energy. The development and execution of the envisioned Smart Grid Pilot will be a collaborative effort between National Grid, the leadership of the State of Rhode Island, its customers, and market participants. National Grid hopes that each will participate fully to reach the goals envisioned and we will be able to demonstrate the opportunity and value of Smart Grid.

The Pilot is designed to accomplish the following:

1. Demonstrate how large scale regulated investments in Smart Grid infrastructure can deliver significant benefits to customers and society.
    - Customer benefit will be measured by a reduction in load and associated cost, improvement in power quality and reliability.
    - Societal benefits are measured in reduction in load and associated carbon reduction.
2. Demonstrate how customer energy consumption and peak demand can be consistently and significantly reduced through the implementation of technologies that provide timely energy usage information, diverse rate plans, and automation to incent and enable customers to reduce load or otherwise alter their consumption patterns.
    - We will establish a baseline usage for the deployment area and then use control sets of customers with differing solution sets to determine the effectiveness of each approach.

3. Demonstrate how electric distribution grid operating efficiency can be improved measurably by improved monitoring and control.
    - This benefit is measured in terms of potential future reductions in line losses.

4. Demonstrate opportunities to optimize transmission network performance through enhanced distribution network information and control, and changes to customer behavior.
    - This benefit is measured through reductions in critical peak loads with the combination of technology and rate mechanisms. These lower critical peak

loads reduce the overall stress on the system. Stress degrades equipment and causes reliability challenges.

5. Demonstrate how distribution feeder reliability can be improved through the implementation of improved monitoring and control of the distribution grid and the integration of automated meter outage detection and restoration into a new digital distribution management system and a new outage management system.
    - This benefit is measured by reductions in customer minute interruptions.

6. Demonstrate how distributed resources (both generation and storage) could be safely and reliably incorporated onto the electric distribution grid through the implementation of improved monitoring, protection and control capabilities.
    - The measurement will be the quality and usefulness of near real-time information and controls and the benefit will be a reduction in carbon-based load and an increase in availability of renewable generation.

7. Demonstrate how Smart Grid technologies (including advanced meters) improve customer satisfaction by providing timely consumption and conservation options, automated load control and alternative rate plans, and improved monitoring and control of the distribution grid.
    - The measurement will be greater customer satisfaction as measured by improvement in energy savings and customer satisfaction as measured through surveys.

8. Demonstrate how Smart Grid technologies can be deployed in configurations that are interoperable with both existing technologies and anticipated future technology enhancements.
    - The measurement will be a solution that is open and interoperable in accordance with existing industry standards and NIST/NERC/FERC guidelines. The benefit will be lower initial costs and long-term technical flexibility to comply with emerging standards.

D. Smart Grid Security

The advent of the Smart Grid, smart homes and smart metering all require communications and the ability to control devices that provide electricity to customers and manage the grid. Communications security for the distribution grid has not been an issue in the past, since there were almost no automated controls or remote sensors in the distribution grid. Over the last few years, the issue has been explored by a number of industry working groups resulting in an

extensive list of security standards, borrowed from the telecommunications community and other industries, to address Smart Grid security.

Under the Energy Independence and Security Act (EISA) of 2007, the National Institute of Standards and Technology (NIST) has "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems…" [EISA Title XIII, Section 1305]. National Grid is participating in the NIST interoperability working groups directly and via strategic relationships with vendors such as Capgemini. Through this participation, National Grid is aware of the interoperability roadmap material developed by NIST, and more importantly, the raw information and processes it is based upon. National Grid's end to end Smart Grid design incorporates industry standards already identified via the NIST process and will incorporate modifications and additional standards, as required, and in conjunction with key equipment and software vendors, when they are adopted by NIST.

National Grid believes none of the specific objectives of its proposal will be impacted by the lack of existing, or the introduction of new, final interoperability standards. This belief is based on the list of existing standards published by NIST on May 18, 2009. While not final, none of the standards published to date, or recommended by the NIST workshop processes, lack adequate interoperability or the required level of security that would prevent National Grid from deploying an effective Smart Grid solution.

National Grid is also monitoring smart grid cyber security activities of FERC under the authority granted the agency in ESIA. In the legislation, FERC was tasked to approve Smart Grid interoperability and Security Standards. Accordingly, they have advised NIST to undertake the necessary steps to ensure that each standard and protocol that is developed as part of the Institute's interoperability framework is consistent with the overarching cyber-security and reliability mandates of the EISA as well as existing reliability standards approved by the Commission pursuant to Section 215 of the Federal Powers Act. The Commission proposes to make consistency with cyber- security and reliability standards a precondition to its adoption of Smart Grid standards. While additional legislation may alter some of the roles for key agencies, we recognize that NIST will likely remain the focal point for Smart Grid Standards. In the interim, the recent efforts by FERC to add some degree of clarity to the standards discussed so the industry can move forward, provides National Grid with a set of guidelines within which we can confidently develop a Smart Grid Security approach. We will, therefore, include the following activities in the Company's Program:

- National Grid will endeavor to comply with the eight Critical Infrastructure Protection (CIP) Reliability Standards of NERC.
- National Grid will ensure that our selected vendor partners are participants on the appropriate standards development groups and compliant with the NERC CIP Reliability Standards.

- National Grid has engaged one of the foremost authorities in Smart Grid Security, Doug Houseman, Capgemini CTO, to oversee security compliance. Mr. Houseman will make every effort to ensure that National Grid is aligned with appropriate industry guidelines.
- National Grid will not simply assume that compliance with standards is adequate, we will test our systems using outside security experts to identify vulnerabilities and adjust our approach to fill any gaps.
- National Grid will also program the processes and procedures required to provide a long-term secure environment.
- National Grid will feed back to the various industry working groups lessons learned to help accelerate the completion of good standards.

E. Pilot Approach

National Grid has reviewed a variety of Smart Grid programs conducted by other utilities and has found that most focused on testing the functional characteristics of various technologies. These programs made important contributions to the maturation of Smart Grid technology, especially as they relate to the viability of various communications technologies and methods. National Grid seeks to build on that work, not repeat it. While the Company's proposed Pilot will confirm that the selected technologies offer a robust mix of capabilities to support Smart Grid and Clean Energy functions, National Grid is also seeking to achieve a much broader understanding of the impact of both on its customers and business.

The proposed pilot is designed to demonstrate the Smart Grid in a manner, and at a scale, that will provide strong evidence to support the future deployment of these technologies, while still being cost effective for Rhode Island ratepayers. With a Smart Grid, customers can exercise greater choices about, and control of, their energy use. At the same time, managers of the electric distribution and transmission grid will have a powerful new set of tools to improve efficiency, reliability, and security. The existing performance of the network will be "base lined" (system performance data collected) before the Program is mobilized to enable a comparison of performance data before and after the Company's Smart infrastructure is deployed.

Smart Grid has the potential to allow Rhode Island customers to continue to increase their use of wind assets, while our grid managers can study the impact to the grid and the business that results from the introduction of concentrated levels of new energy technologies. Smart Grid will enable the scalable testing of the balancing potential of storage on intermittent wind generation as a deployable source of energy in locations and during periods of congestion. This approach could provide alternatives to new centralized generation, creating clean, reliable, rapid solutions to increasing energy demand.

Similarly, the scale and embedded testing of smart and green will enable manufacturers of both technologies to improve their understanding of each and create a collaborative environment where both can be enhanced and more easily integrated.

F. Customer Aspects

The proposed Pilot will empower participants to reduce their energy consumption by first allowing them to understand their energy usage at a level of detail, timeliness, and ease that was previously impossible, and by providing new tools and services that will help them better manage their usage. National Grid's Smart Grid will enable new interfaces with customers such as web tools, text messaging, and home display units (in addition to improving information richness in traditional bills and bill messaging). These interfaces are an essential link, providing tailored solutions to customers, encouraging more interaction and offering timely and useful information that will support customer-driven energy management.

National Grid believes customers will respond to the heightened awareness created by the Pilot, but also believes that behavior shifts can be best optimized if incentives are also available through innovative rates that create more alignment between customer pricing and the wholesale markets. Customers will be given the opportunity to choose among three new Standard Offer rate alternatives ("Smart Grid Pricing"), i.e., Critical Peak Pricing Program, Peak Time Rebate, and Hourly Pricing Program. This approach, together with a choice of interface channels, enables customers to choose pricing options, as well as their method and time of communications with National Grid, resulting in greater customer choice, convenience, and a higher quality interaction.

The data and knowledge created by the Company's Pilot can also be combined with technologies that empower customers and electric distribution grid managers in other new and powerful ways. These include home area networks that support home energy automation tools, which can monitor and optimize appliance performance, enable embedded demand response in a manner that is transparent to customers, while remaining supportive of both the customer and the grid.

G. Utility Aspects

Electric utilities are at a transformational juncture. Restructuring and other changes have affected the industry's structure in recent years in sometimes radical fashion, but those transitions left essentially unchanged the roughly century-old manner in which electricity is generated, delivered, and consumed. National Grid's Smart Grid will enable significant changes in these areas by overlaying communications capability along the grid and inside the customer's home or business, enabling the rapid flow of information (much of it never before available) and

near real-time control. For National Grid and others, these changes will require a variety of new approaches to service delivery, pricing and operational processes.

The proposed Pilot will allow National Grid to develop an understanding of the operational changes that can occur along its electric distribution system and within its business processes in order to better plan the transition to a smarter grid with increased amount of distributed generation resources. This crucial expertise cannot be developed simply by reading reports of the results of other utilities' Smart Grid pilots. The systems and processes at each utility are sufficiently distinct, and the transition to a Smart Grid is so significant and affects so many fundamental processes, that learning by doing is the only way to transition to this new paradigm of energy delivery. The Company's Pilot creates a process through which National Grid can achieve this knowledge.

H. Technical and Functional Guiding Principles

The design principle National Grid has adopted is to think of the Company's Smart Grid as a spine or backbone of core functionality to which elements can be added in a modular fashion. These modules form part of the Company's vision for the future, e.g. Wind Energy Storage, Plug in Hybrid Vehicles, etc. The Company's Pilot proposal will focus on a core distribution grid area Spine but also will include a Wind/Energy Storage Clean Energy Module.

National Grid's approach to designing its Smart Grid also recognizes that the Company is at the beginning of a broad change to the electric industry. The Company must continue seamless electric delivery operations during this transition. We must integrate legacy systems, business and operational processes, while we are adding new smart technologies and changing key operational functions. Our planning reflects this reality.

National Grid's design approach considers both existing and developing standards and guidelines for interoperability. This approach minimizes the risk of stranded investments, while ensuring that we are aligned with leading industry organizations. These include the International Electrotechnical Commission's interoperable communications and nomenclature standards for substation automation; and Common Information Model design principles under consideration by the National Institute of Standards and Technology; National Electrical Manufacturers Association standards for plugs, Reclosers and wiring; and the Institute of Electrical and Electronics Engineers (IEEE 802.x) for various Internet Protocol standards. National Grid believes that open, interoperable systems are the most cost-effective approach and we recognize the key role that this approach will support in an industry that will rapidly evolve.

National Grid has recently conducted broad market testing via a request for information ("RFI") process for Smart Grid, which involved over eighty vendors of equipment and services. The design of the process encouraged competition as vendors could bid on any combination of

twenty-two categories covering Grid Automation, Communications (Home, Local and Wide Area Networks), Systems, Advanced Meters, and Home Automation solutions. We have also conducted a thorough review of the market for green technologies and include a variety of these in our proposed Programs.

I. Smart Grid Functional Strategy

National Grid's strategy overlays the electric grid with a two-way communications network with speed and capacity sufficient to enable advanced metering, home energy automation and management, and distribution automation and management, and to support distributed generation and energy storage functions. National Grid has some existing network assets that can be utilized to support the Smart Grid communications infrastructure. These include fiber and microwave facilities that can be used as part of the Smart Grid Pilot. Wherever possible, National Grid is incorporating these existing assets and systems into the Pilot design.

The specific business activities that the Pilot will enable include:

Customer Facing Functions

- Provide interval metering for residential and commercial customers in the Pilot footprint.
- Provide alternative rate plans including event-based critical peak pricing, event-based peak time rebate, and hourly pricing.
- Provide National Grid customer service representatives with meter status, consumption and appropriate home automation related information.
- Provide energy consumption and pricing information to customers in their home or business through a choice of media that they can select including:
    - Web
    - Home Display Unit
    - PDA/Text Messaging
    - Telephone
- Provide customers who choose the ability to control thermostats and energy consuming devices in their home or business manually or programmatically (and via wireless mobile devices for those customers participating in certain remote automation technology programs).
    - Enable (with customer agreement and override capability) remote control by National Grid of thermostats and energy consuming devices in customer homes and businesses.

Distribution Grid-Facing Functions

- Enable monitoring and remote control of distribution equipment, including monitoring feeders and transformers, and monitoring and control of capacitors, reclosers, voltage regulators and switches.
- Incorporate automated meter outage and restoration events into outage management systems and processes.
- Enable distribution operators to query remotely the outage / restoration status of individual meters and groups of meters to confirm outage scale and restoration status.
- Provide digital distribution grid operational data to grid operators via a new Distribution Management System in a much shorter timeframe and at a level of granularity sufficient for engineering analysis and asset management applications.
- Install monitoring and control capability in substations and along the grid that will enable National Grid to assess how to safely introduce and control a significant quantity of distributed generation supply and storage (including intermittent sources) onto the distribution grid.
- While a smart grid is not required to enable a certain level of distributed generation, our view is that the market is moving quickly to a distributed model in which both the adoption and concentration of these resources will quickly overwhelm the existing electric system. Adding smart sensor along the grid will enable near real-time monitoring of the system, while remote switching will enable rapid reaction to potential overloads or rapid swings in loads associated with variations in distributed supply or demand.
- Enable remote reconfiguration of loop or interconnected distribution network assets to isolate and minimize outage impact.

J. Pilot Scale

National Grid currently serves approximately 477,000 electric customers in Rhode Island. As will be discussed in Section K of this Executive Summary, the Company proposes a Smart Grid pilot, which will include a number of substations and feeders in the Newport County area. The total number of residential and commercial customers associated with this particular infrastructure is just over 10,000. This sample size will help to support decision making for a scaled roll out, as it is a valid sampling of a range of customer segments (urban, suburban, rural), customer types (single family, multiple dwelling, small business), relevant and available third-party demographics (such as income, education, and technology adoptions) and load profiles (low to high, average, peak and seasonal). This deployment area will also allow the Company to include a sufficient number of distribution substations to test a broad variety of network infrastructure models. This will include radial and loop or interconnected feeders, a large number of transmission and distribution system control devices, and offer a greater potential for introducing and testing distributed generation and storage options.

The Pilot area is geographically concise and electrically contiguous, enabling extremely comprehensive and thorough testing of Smart Grid. This simplifies communication with external stakeholders, such as municipalities, and reduces marketing cost, since National Grid will only target a single media market. This approach will also (1) allow National Grid to focus internal resources in a single geographic area, reducing deployment time and cost; (2) enable automated switching along or between feeders to test the potential of smart grid automation to limit outage impact; and (3) permit testing of mission-critical communications by providing redundant communication technology for substation operations.

K. Proposed Pilot Site

National Grid proposes to run the Pilot in the Newport and Jamestown areas and will also include two feeders in the Portsmouth area that serve existing wind generation assets at customer facilities. This decision is based on the objectives and scope of the pilot outlined above as well as the following advantages:

1. Unique Distribution System Conditions: As previously stated a primary objective of the Pilot is to demonstrate how customer energy consumption and peak demand can be consistently and significantly reduced through the implementation of technologies that provide timely energy usage information, diverse rate plans, and automation to incent and enable customers to reduce load or otherwise alter their consumption patterns.

   The Company's Distribution System Planning department has examined all the loads served by the L14 and M13 lines that terminate at Dexter #36 substation in Portsmouth. The customers served are in the communities of Newport, Middletown, Portsmouth, Jamestown and Prudence Island. Many of these same customers were identified as participants in the System Reliability Procurement Plan's "Aquidneck Island" component. Inclusion in this Smart Grid Program may significantly improve their reliability.

   There is a wide variety of loading issues associated with the selected deployment area and the situation is expected to worsen in the next ten years as a result of an anticipated average annual load growth rate of 2.25%. The primary issue is thermal loading on substation transformers, sub-transmission systems and distribution feeders; loading above tie capabilities; and load above acceptable risk levels. The Company believes the Smart Pilot will offer significant improvements in its ability to see and react to real time system data and, therefore, respond to high loads and fault conditions within this area real-time and remotely. Other aspects that make this particular location attractive for such a Pilot include an aging infrastructure, limited space for system growth, and fewer options due to the specific locations on islands with limited access to adjacent

distribution systems. In many ways, the selected location, representing a broad combination of challenges, offers the ultimate test for the Smart Grid.

The company has evaluated several options to relieve these issues, including installation of a new substation and three 13.8KV feeders. To date, no suitable site for the new substation has been identified. An alternative approach includes reinforcing the existing 23KV sub-transmission system. This alternative, like the substation replacement, is time consuming and expensive. Beyond the ability to quickly recognize and respond to operational issues on the system, a primary purpose of the Smart Grid pilot will be to determine if the combination of technology and creative rates can achieve ample peak load reductions on the existing area substations, alleviating or at least deferring, the need for the much larger capital investments.

2. Proximity to Existing and Proposed Distributed Generation: A key objective of the pilot is to provide the backbone for potential distributed generation and storage resources, in order to determine whether or how these resources can be safely and reliably incorporated onto the distribution grid through the implementation of improved monitoring, protection, and control of the distribution grid. Portsmouth currently has two large wind turbines – at Portsmouth Abbey and Portsmouth High School. Additionally, the U.S. Navy has expressed interest in building wind turbines at Naval Station Newport and the Town of Jamestown has formed a committee to study the possibility of erecting wind turbines on the island. These projects, especially if combined with adequate storage, may provide alternatives energy options for the overheating and loading issue noted above, while providing the optimum test of the linkages between Smart Grid infrastructure and wind resources within the state of Rhode Island.

3. Diverse Customer Demographics: Newport County is home to a diverse population of residential and business customers. The behavioral characteristics of different customer groups and differing rates and levels of automation will aid in understanding the implications and benefits of implementing Smart Grid technology more broadly.

L. Site Characteristics

The Pilot area includes five substations, the feeders supplied by these substations, and the customers supplied by the feeders. These substations are:

- West Howard Substation, Newport
- Harrison Substation, Newport

- Dexter Substation, Portsmouth
- Clark Street Substation, Jamestown
- Eldred Substation, Jamestown

Maps of the area covered by each substation, including overlaying GIS coordinates, are included in Attachment 1. Based on the areas served by the substations listed above and the associated feeders, the total number of active customers to be covered by the Pilot as of June 1, 2009 would be 10,169. The number of Pilot customers in each rate class is outlined in Attachment 2. A complete list of feeders together with number of customers and equipment on each feeder is included in Attachment 3.

M. Clean Energy Module – Wind Energy Storage

We propose to deploy the storage either directly with or electrically contiguous to existing customer-sited wind capacity in Rhode Island to study opportunities to use energy storage to improve integration of wind power. We propose to use the wind energy storage module to offset the intermittent availability of distributed wind energy, creating a more predictable and reliable energy resource. The Smart Grid will enable interconnect, monitoring and control of these clean energy resources.

The existence of two customer-sited wind turbines in Portsmouth, RI – a 1.5 MW unit at the Portsmouth High School and a 660kW unit at the Portsmouth Abbey School – presents National Grid with a unique opportunity to study the costs and benefits of using energy storage to improve wind power integration. The primary focus of this module is to install energy storage at the appropriate location(s) to integrate with the operation of these two wind turbines. Specific decisions regarding location (s) (e.g., with the turbine vs. at the substation) and performance characteristics (e.g., power vs. duration) will be determined as part of this program.

In addition to this field work connected to the Smart Grid program in Rhode Island, this module also includes a detailed study of how offshore wind capacity could be integrated in Rhode Island in the future.

N. Pilot Cost

The overall cost of the Rhode Island Smart Grid Pilot is estimated at $59 million. The cost incurred by Rhode Island customers will be significantly lowered by two factors,

- The project has been designed to qualify for matching DOE funds that could reduce costs by 50%.

- The costs quoted include "fixed costs" that could be shared across the larger National Grid service area subject to regulatory approval in more than one state - National Grid has filed Smart Grid proposals in both New York and Massachusetts and if successful the common fixed costs would be shared proportionately.

The current Rhode Island costs (stand alone) are in the following key categories:

- Hardware
- Software
- Services

The stand alone costs of the Pilot for Rhode Island on a per meter basis is $5,800. The cost of equipment and associate software will be much lower when acquired in mass. The integration and services required to enable this pilot can lay the groundwork for a mass deployment, but cannot reflect the broader value that can be obtained in a broader deployment. While National Grid anticipates that the benefits of a smart grid will outweigh the costs in a mass deployment, not all potential benefits can be realized in a pilot. One benefit that can be realized is the direct benefit of load reduction, which is a significant objective of this Pilot.

Attachment 4 shows how the cost per meter could potentially change under several regulatory approval and fixed cost sharing scenarios.

O. American Recovery and Reinvestment Act of 2009 (ARRA)

Under ARRA, approximately $4B is allotted to the DOE's Office of Electric Delivery and Energy Reliability to support implementation of the smart grid programs authorized by EISA 2007. These include Smart Grid Investment Grants (SGIG) as authorized by Title XIII, Section 1306 and Smart Grid Demonstration Programs (SGDP) authorized by Title XIII, Section 1304. Each program has a specific intent which collectively are designed to advance the realization of a Smart Grid:

- *The intent of the SGIG FOA is to provide grants of up to one-half of qualifying smart grid investments to support the manufacturing, purchasing and installation of smart grid devices and related technologies, tools, and techniques for immediate commercial use in electric system and customer-side applications including electric transmission systems, electric distribution systems, building systems, advanced metering, appliances, and equipment. <u>The ultimate aim is to enable smart grid functions on the electric system as soon as possible.</u>*

- *The intent of the SGDP FOA is to provide financial support, up to one-half of the total project cost, to demonstrate how a suite of existing and emerging smart grid technologies*

> *can be innovatively applied and integrated to prove technical, operational and business-model feasibility. The ultimate aim is to demonstrate new and more cost-effective smart grid technologies, tools, techniques, and system configurations that significantly improve upon the ones that are either in common practice today or are likely to be proposed in the SGIG Program. Furthermore, these demonstration projects should serve as models for other entities to readily adapt and replicate across the country.*

The guidelines for funding under each program have now been released.[1] The focus of the SGIG Program is rapid smart grid enablement using commercial technologies. The focus of the SGDP Program is to demonstrate creative application of existing and cutting edge smart applications that results in cost-effective use and advancement of the technology. The Company intends to apply for matching funds in SGIG and/or SGDP programs.

For the Smart Grid Investment Grant Program (DE-FOA-0000058A), DOE will permit applicants to submit applications on or before three due dates with the requirement that all funds be awarded by September 30, 2010. The three application due dates are: August 6, 2009; November 4, 2009; and March 3, 2010. DOE cannot predict that funds will remain available beyond the first award date. After the August 6, 2009 deadline, a ninety-day review period follows, which would allow the DOE until November 4, 2009 to award grants to first- round applicants. For the Smart Grid Demonstrations FOA (DE-FOA-0000036), DOE has announced an application deadline of August 26, 2009.

The Smart Grid Investment Grant Program (DE-FOA-0000058A) acknowledges that some projects may need state regulatory approval, and requires that applications include correspondence from the relevant regulatory agency indicating when the approval process will begin and outlining the likely timeline. Although applicants that do not have regulatory approval remain eligible to receive an award, DOE may withhold some or all of the grant funds until regulatory approval is obtained. The Company believes that its application for federal funding will be disadvantaged if regulatory approval has not been received in advance of the November 4th decision schedule.

National Grid expects the application process for stimulus funds to be extremely competitive and we are committed to working closely with regulatory bodies in each state we serve in order to submit a winning application to DOE on or before the first due date. The Company views this as a tremendous opportunity for each state we serve to begin deploying the electric grid of the future while providing high quality "green collar" jobs.

In addition to two-way communications, advance meters and smart enabled distribution equipment, referred to here as the "Spine" of a Smart Grid, ARRA funding also supports

[1] https://www.fedconnect.net/Fedconnect/PublicPages/PublicSearch/Public_OpportunitySummary.aspx

integration of a series of generation and storage options, which the Company refers to as Clean Energy Modules. These Modules can include any of the technologies required to demonstrate:

- how the Smart Grid can accommodate, accelerate, or increase the penetration of all generation and storage options (e.g., energy storage and wind generation)

- how the Smart Grid can use or exploit generation or storage technologies for the benefit of the overall system and for all rate payers e.g., wind that reduces peak system demand thereby reducing the need for additional generation capacity.

P. Next Steps

While National Grid's Smart Grid proposal is pending before the Commission, The Company intends to prepare for implementation by undertaking design, testing, training and furthering the commercial negotiations with vendors for all of its proposed Smart Grid pilots. That way, if and when any one state regulatory body approves a proposal, National Grid's lead time for implementation will be shortened, improving our chances of obtaining matching funds from DOE. A mobilization plan is included in Section VIII of the filing showing the sequential steps. National Grid anticipates that delivery lead times for certain critical Smart Grid equipment will begin to slip as the impact of ARRA funding begins to create greater demand. Therefore, an expedited approval by the Commission is essential to meet the planned timeline. In addition, the Pilot is also subject to National Grid's internal review and approval process, which will occur concurrently with the Commission's review.

II. CUSTOMER AND STAKEHOLDER EXPERIENCE

National Grid's SGIG and SGDP Programs will have both direct and indirect effects on the Company's customers. The Company will provide all participating customers smart electric, and where applicable, retrofit their gas meters with smart communications modules. A subgroup of participating customers will receive technology inside their homes or businesses with varying degrees of information and controls for managing energy usage. In addition, new rate alternatives proposed will allow participating electric customers the flexibility of saving money as they adjust to the realities of market pricing. Of course, these new technologies and new rates will require customer education, which we have anticipated in our deployment plan. With the exception of the installation of in-home devices, the above are traditional utility activities for which National Grid's existing programs and policies are well adapted. Processes for in-home installations, while not part of the Company's existing services, are sufficiently close to National Grid's core competencies that National Grid is confident in its ability to perform them. We are also working closely with industry experts who have experience installing these devices to guide the Company's efforts.

The Smart Programs involve much more than equipment installation and new tariffs. The capabilities enabled by our Smart and Clean Energy Program will result in fundamental changes in customer access to energy information and their ability to control and manage energy usage. To effectively implement the Program, customers must receive sufficient information to interpret and act on the new data and master the new capabilities that will be available to them. National Grid will provide information in the following ways:

1. Coordination with related marketing, education and outreach programs, including demand response, energy efficiency, conservation and low income programs.
2. Coordination with providers with similar or related interests and services, such as local governments, community-based organizations, local firms and any overlapping municipal authorities.
3. Comprehensive use of internal methods to reach customers, including billing, bill inserts, company web page and call center.
4. Comprehensive use of external methods to reach customers, including Internet, direct mail, and town hall meetings.
5. Comprehensive outreach to local, state, and regional stakeholders focused on Smart, Clean Energy and Energy Efficiency activities to provide education material and access to subject matter experts.
6. Targeted and tailored marketing that reflects the values, habits and demographics of different target communities and populations.

The Program will provide an opportunity to test these communications and education approaches in order to determine their effectiveness. What National Grid learns will inform our broader rollout.

A. Service Levels

National Grid is working with internal and external resources to develop a comprehensive education plan for customers in the Pilot area. Three levels of service will be offered in phases; each service level will become available as enabling technology is added at the Company, along the grid, and in the customer's home or business. All materials will emphasize that customers are empowered to make choices and should take responsibility for how their home or business uses energy. The Company is in the process of developing a comprehensive evaluation methodology for each service level to determine how customers' energy usage varies both between each service level and as compared to customers outside of the pilot area with similar baseline energy usage patterns.

i. Level One.

The Level One Pilot program provides customers with time of day rate offers, on-demand consumption information, and information about actions they can take to lower their energy costs. In this level, hourly energy consumption data is available to customers either on the Internet, through bi-directional text – messaging, or via a Home Display Unit (HDU). As technology and capabilities become available during this level, customers will be encouraged to take control of their energy usage with the introduction of dynamic pricing. At a minimum, National Grid expects that time of use pricing will be available at this level, and peak pricing may be offered as well. As functionality is added to the enabling systems, the Level One services will record customer peak load via a smart meter and offer a pricing plan that encourages off peak usage.

ii. Level Two.

Under the Level Two services, customers can set a monthly energy expense target and National Grid will help them stay on course by providing on-demand account status and suggestions to help them adjust their energy usage if it appears they are not on track. Customers will have access via the Internet (as well as through a home display unit, if they are participating in the Home Automation Pilot initiative) to on-demand information and progress reports regarding their energy consumption, as well as access to strategies to improve energy efficiency and savings.

In addition to the benefits outlined in Level One, customers who chose Level Two will receive, via email or text message, National Grid "Energy TARGET Plan Alerts" indicating their status (on-track/off track) relative to their target. Further, customers will receive information about how they compare to their neighborhood and to other customers with similar homes.

iii. Level Three.

The Level Three offering will provide various home automation options and may include Grid Modules that enable a more robust integration of distributed generation and storage. This plan allows consumers to manage their energy by programming a sophisticated panel that communicates with the electric grid. Customers will have the option, either instead of or in addition to managing their home automation capabilities themselves, to authorize National Grid to take certain actions to reduce their energy use or shift their usage to lower-priced times during certain peak load conditions. This activity could include remotely resetting programmable thermostats by an agreed amount or directly cycling certain high energy consumption systems such as air conditioners off within agreed timelines.

Attachment 5 summarizes the business capabilities under each service level.

B. Marketing Plan

Aggressive marketing, education and outreach will be critical to encourage customers to reduce their energy consumption. The Pilot seeks to encourage a fundamental change in consumer behavior, while increasing customer satisfaction. Significant education will be needed to inform customers of available service levels and the benefits of participating in the Pilot. National Grid's education and marketing effort will target all residential customers in the Pilot footprint, eligible commercial customers, and community leaders. The specific objectives of the marketing plan are to

- Create awareness of the Pilot and the information and options it provides.
- Educate customers about the benefits, to them and to society, of a Smart Grid.
- Encourage customers to take advantage of the new information and capabilities offered by the Smart Grid.
- Motivate customers to permanently change their energy usage behavior.
- Inspire customers to become advocates of energy usage modification.

The customer education plan includes a phased marketing approach beginning at the time of regulatory approval and continuing throughout the Pilot period. The plan will communicate Smart Grid concepts in a clear and simple way, engage pilot participants in one-to-one demonstrations, and make it easy for them to understand how to take advantage of all the benefits the Smart Grid has to offer.

In order to design the marketing plans for the Company's Smart Grid filings, National Grid conducted eight focus groups with residential and business customers throughout its service territory. Two of these focus groups, one business and one residential, were held in Rhode Island. This research revealed that customers feel they lack control over their energy use. They believe that having information available to them about their usage would be the first step in controlling their energy consumption. Most focus group participants acknowledged that they needed additional information and motivation to modify their behavior. National Grid used the information gathered from these groups to develop its customer education strategy, and will carefully analyze its experience during the Pilot to refine these findings by determining which education approach is most effective.

Customer and stakeholder education will focus on developing an understanding of the benefits that can flow from real time energy usage information and dynamic energy pricing as well as the positive environmental impact that targeted personal adjustments to energy usage can achieve using a Smart Grid. National Grid will encourage greater participation in its energy efficiency programs. A cornerstone of the marketing program is the development of the "Smart Squad."

This outreach team will include ten full time members who are fully trained in Smart Grid technology. The Smart Squad will conduct demonstrations of Smart Grid applications in both one-on-one and community-based settings, and will serve as a neighborhood resource for Smart Grid Pilot participants.

National Grid intends to establish a Smart Grid "Spine" demonstration site in the Pilot footprint to help educate stakeholders. This will be a home in Newport County that will include a full suite of home energy automation tools and Smart Grid technology demonstrations. As the Pilot grows and matures, the demonstration site could also be used to showcase distributed generation, remote storage, and PHEVs. The Company also intends to establish a wind storage "Module" demonstration site adjacent to one of the wind turbines currently located in Portsmouth.

The customer education plan will have three phases: seed, share, and succeed. The "seed" phase begins with regulatory approval and concludes when the Smart Grid becomes operational in the Pilot area. This phase includes launching the Smart Squad, direct mail, public relations and recruiting the "super users," a group who will agree to be the initial test homes and businesses for the technology.

In the "share" stage, the plan moves from announcement and recruitment activities to building awareness, education, and engagement. Pilot participants will be introduced to the Smart Grid via a welcome kit containing a DVD that chronicles the Smart Grid experience. National Grid's website will have Smart Grid planning details. Monthly bill inserts will also include information. National Grid will provide updates by a solar powered billboard in the Pilot area, electronic newsletters, and direct mail. Additional plans include a series of educational breakfast meetings throughout Newport County, neighborhood contests to drive Pilot participants to achieve greater savings, field demonstration units to engage pilot participants, in-home demonstrations, and education institution partnerships.

In the final stage of the marketing plan, "succeed," the Company will focus on those strategies from the "share" phase that have proven most successful. Attachment 6 contains a timeline and information about the three phases.

National Grid will carefully measure the success of its marketing and education efforts. While no final decision has been made on the exact steps to support this measurement effort, National Grid believes it should include pre- and post-pilot awareness research to measure program impact, marketing channel success tracking, identification and measurement of website metrics, call center tracking, customer participation rates by a variety of demographic and load profiles, and associated savings. Attachment 7 outlines the expected cost for the marketing plan. The total expected cost is $3.7 million. This represents approximately 6% of the total expected project cost of $59 million. Although this percentage is slightly higher than traditional marketing programs, National Grid believes it is justified due to the degree of customer education and incentives likely to be needed to change long-ingrained customer habits and

expectations and to create awareness of and willingness to take advantage of the new energy options made possible by a Smart Grid.

C. Community Outreach

In addition to outreach to our energy customers, National Grid has developed and is already executing a comprehensive plan to inform key external stakeholders, including city, state and federal officials, community associations, education institutions, and the media in each state we serve. This includes an effort to understand the concerns of each stakeholder group as it relates to Smart Grid, conservation, and energy efficiency.

D. Customer Service

As noted earlier, Pilot participants electing to monitor their accounts via the Internet will have access to detailed usage information, pricing, trends and program alerts. Customers phoning into the Contact Center will be able to use their existing Customer Service phone numbers, but will be offered a Smart Grid specific option via the Interactive Voice Response System, routing them to an agent specifically trained and qualified to handle their inquiries. To address the unique needs of Smart Grid Pilot Customers, additional training will be provided for these agents, including not only the technology and applications, but also the broader capabilities and benefits of a Smart Grid and the Pilot objectives. Customer Service representatives will also have information about the new rate structures created for the Pilot and will be able to educate customers on the benefits from the rate plans given their individual situation.

E. Billing

Because of the cost and complexities associated with replacing the systems that support the meter reading to invoicing process, National Grid will invoice Smart Grid Pilot customers through the existing billing systems. Some modifications will need to be made in order to accommodate the proposed new tariff structures outlined below in this section.

Customers in the Pilot will receive a billing statement on a monthly basis. They will also have the option to view their bill online through National Grid's website. Pilot customers will continue to have the same account number they currently have.

Other than a logo at the top of the bill, which will identify the customer as a Smart Grid Pilot customer, the billing statement customers receive will look similar in many ways to their current statement. Name, address, account number, and billing period will continue to be displayed as they are now. The Account Balance section will also remain the same. In the Detail of Current

Charges section, the specifics will be tailored to the tariff that each Pilot customer is on. Pilot customers will continue to receive all bill inserts they currently receive, including standard safety information.

III. TARIFF AND PRICING

A. Introduction

The Company is proposing to make available to customers participating in the Pilot an alternative pricing structure for Standard Offer Service ("Smart Grid Pricing"). This portion of the Company's proposal discusses how the Company proposes to implement Smart Grid Pricing and the rate design underlying Smart Grid Pricing.

The Company proposes that Smart Grid Pricing consist of: (i) a Critical Peak Pricing Program ("CPPP") for most residential and general service customers and (ii) and Hourly Pricing Program ("HPP") for certain large general service customers. Customers on CPPP or HPP may opt out of the pricing programs before the programs start as discussed below. The information and communication capabilities of Smart Grid technology will enable customers to enhance their potential savings through changes in behavior that move electricity consumption away from expensive time periods towards inexpensive periods.

B. Eligibility for Smart Grid Pricing

As discussed earlier, the customers who would be enrolled into the Pilot and would have the applicable metering installed at their locations consist of a cross-section of customers receiving retail delivery service pursuant to the Company's tariffs. Although all customers in the Pilot Areas will have metering installed, only those customers receiving commodity service from the Company pursuant to its Standard Offer tariff are eligible for Smart Grid Pricing.

The Company proposes that Standard Offer Service customers be placed on Smart Grid Pricing and have the opportunity to opt-out if they do not want to take service under the CPPP or HPP portions of Standard Offer Service. Customers on CPPP or HPP rates will be protected from bill increases on an annual basis. The Company will determine the total cost for a year from the CPPP or HPP program and customers' regular Standard Offer Service rates and provide customers with a credit if the CPPP or HPP pricing is more expensive for the year. Customers will retain any savings if their annual bill on CPPP or HPP is less than their regular bill on Standard Offer Service. Customers who opt-out from CPPP or HPP will receive Standard Offer Service under the regular rate and will be enrolled in the Peak Time Rebate ("PTR") program and be credited for any load reductions made during Critical Peak Periods.

C. Tariff Provisions

The Company will propose at a later date to amend its currently effective Tariff for Standard Offer Service to add provisions governing Smart Grid Pricing. The more important provisions are described below and in following sections.

National Grid proposes that Pilot customers remain on Smart Grid Pricing for twelve consecutive months. Although the Company would prefer to allow more flexibility in order to promote the operation of the competitive electricity market, the design of the wholesale capacity market and the Company's currently effective Tariff for Standard Offer Service inform National Grid's decision to have Pilot customers remain on Smart Grid Pricing for at least one year in order to fulfill their obligation under the tariff. Specifically, ISO-NE charges wholesale suppliers for a capacity tag determined at the time of the annual system peak. The monthly cost for the capacity tag moves with customers as they change suppliers. If a customer chooses an alternative supplier for the summer months, they may return to Standard Offer Service during lower cost months due to lower cost and their capacity tag will follow with them to the supplier of Standard Offer Service. This could result in a significant under-recovery of Standard Offer Service costs associated with these customers during those months. Thus, the Company proposes that customers remain on Smart Grid Pricing for twelve months to facilitate adequate recovery of Standard Offer Service costs.

D. Rate Provisions and Design

As stated above, the Company is proposing two alternative pricing structures as part of Smart Grid Pricing. The first, the Critical Peak Pricing Program, or CPPP, would be available to residential and most general service Pilot customers. The second, the Hourly Pricing Program, or HPP, would only be available to certain large general service Pilot customers. All Pilot customers must be receiving Standard Offer Service to be eligible for Smart Grid Pricing.

i. Critical Peak Pricing Program

CPPP offers customers an opportunity to reduce load and therefore the amount of their bill based on a few hours in a year. Critical peak pricing is designed to recover most of the costs for generation capacity in the hours that have the greatest need for peak capacity. Generation capacity is built to meet the hours of highest demands with a reserve for emergencies during those times. Typically, fewer than 1,000 hours in a year will cause the need for a significant amount of generation to be available to serve peak loads. Company studies show that fewer than 250 hours in the year cause a need for 5000 to 7000 MW of capacity in the region. This represents at least 20% of the system load at the time of the ISO-NE system peak in the last three years. CPPP contains higher prices for those hours. This provides two benefits. First, the savings from shifting load away from the critical peak period is much more significant than traditional

time-of-use pricing structures which are characterized by very long on-peak periods that result in lower prices over that period as capacity cost is spread over a longer period of time. Second, customers are afforded a greater degree of flexibility in responding to price signals with critical peak pricing given the relatively few hours that high prices will be charged during a year.

In its Smart Grid Pricing, National Grid proposes three time periods with different prices for the CPPP for eligible Pilot customers. The first time period is an off-peak period which has the lowest prices. This period includes all weekends, holidays and the weekday hours beginning at 8:00 p.m. and ending at 8:00 a.m. The second period is for non-holiday weekdays from the hour beginning at 8:00 a.m. and ending at 8:00 p.m. This daily period is chosen to recognize that, on average, electricity prices are higher during the weekday. The third period is the critical peak period. This is the feature that distinguishes critical peak pricing from time-of-use pricing. Although the critical peak hours will occur on weekdays, the exact times these hours occur cannot be predicted accurately and are, in fact, event driven. Thus, no set definition of critical peak hours can be provided; rather such hours are "called" based on load and weather conditions expected in the next 24 hours. For example, if ISO-NE forecasts very high loads or peak conditions for the next day, National Grid will notify customers using Smart Grid technologies that electricity prices for the next day will be at much higher levels during a certain time of day.

The selection of days with critical peaks requires careful analysis of system loads from ISO-NE. National Grid has employed a statistical technique called Cluster Analysis to place days into groups with similar peak loads. Cluster Analysis puts load levels into groups in a way that decreases the differences between loads within a group while increasing the difference between groups. The analysis used the peak load in each day for 2008. The analysis resulted in 31 days falling into the cluster for the highest peaks.

The Company further reviewed the days identified by this analysis to define the number of hours to apply the CPPP. The Company counted the number of hours in these critical peak days that were above 21,000 MW of load. This approach is based upon a review of the daily load curve in each of these days. Summer load patterns have smoothed to a very flat pattern for peak days. Thus, National Grid selected the hours above a load level that does not occur on any other day of the year except for the days in this grouping. This results in a total of 173 hours for 2008.

ii. Design of CPPP Standard Offer Service Rates

National Grid proposes to offer CPPP as an alternative Standard Offer Service pricing option for commodity service provided to Pilot customers. The goal of the CPPP is to motivate customers to shift their electric usage away from peak-priced hours or by simply using less electricity during those hours by providing them the opportunity for potential reductions in their electric bills.

Pilot customers on CPPP will continue to receive Standard Offer Service from the Company. National Grid will account for their Standard Offer Service load as it normally would under their retail delivery service rate class and will reflect this when procuring Standard Offer Service. Since Smart Grid Pricing is optional, wholesale suppliers may not be interested in submitting bids for a very small group of customers (approximately 10,000). Thus, a rate design must be created that reflects CPPP principles but recovers the costs of Standard Offer Service for Smart Grid Pricing customers.

National Grid proposes to design alternative Standard Offer Service rates for CPPP using ISO-NE energy prices and capacity costs as a guide. The approach is similar to marginal cost pricing which was typically performed prior to restructuring of the electric industry in Rhode Island. In this approach, hourly energy prices and hourly loads are used to compute a load-weighted average energy price for each CPPP period. As it applies to the Pilot's Smart Grid Pricing, the source of the relevant data is the ISO-NE information for the Rhode Island load zone. In addition, the cost per kW of generation capacity is calculated on a cost per kWh basis for the critical peak period. These results must be adjusted to insure recovery of Standard Offer Service costs for a 12-month period.

For the purpose of the Pilot, National Grid proposes to collect all costs for capacity for alternative Standard Offer Service customers in the critical peak period. The addition of these costs to the average energy charge for that period will promote savings for customers who volunteer for CPPP and will keep rates lower in the other periods. Also, these are the hours in which the system peak load will occur and any load reduction by customers during these hours will save on the costs for incremental generation capacity.

Under the Forward Capacity Market[2] of the ISO-NE, a customer's annual capacity obligation is determined by its load at the time of the ISO-NE annual peak. Any customer's load at that time would incur a monthly capacity charge during the following year. The load would be adjusted for reserve margin needs of 15% and losses of 8%. The annual cost for one kW will be calculated and divided by the number of hours in the critical peak period for 2008 (hours above 21,000 MW) to produce an hourly critical peak capacity price in dollars per kWh. Under our proposal, the Company can call this price for 175 hours on 30 days in the year.

As discussed above, National Grid proposes to recover 100% of the capacity cost in the critical peak period, which will require the Company to forecast capacity costs for these periods. The risk in this approach is that the peak occurs outside this period and no charge is made for capacity. However, the Pilot will provide the opportunity to study (i) whether the CPPP price is effective, (ii) whether the customer reacts to these high prices in the critical peak period, and (iii) to assess the risk factors in designing the CPPP rate in this manner.

[2] The charges for capacity costs have a number of associated credits and charges in any given month under the ISO's billing rules.

iii. Peak Time Rebate

Pilot customers who do not wish to participate in CPPP or HPP will be able to use Smart Grid technology to participate in a simpler option to reduce their electric bill through demand response. Those customers may elect to participate in Smart Grid Pricing by earning a rebate during critical peak periods. National Grid hopes to determine whether customers will be attracted by the simplicity of this offer and, if so, are there any distinguishing characteristics of this group of customers which led them to elect this option over CPPP or HPP.

Pilot customers who elect PTR will be charged for Standard Offer Service under ordinary Standard Offer Service rates for their rate class but will have the opportunity to earn a credit when notified of a critical peak period. The Company is proposing the credit be equal the calculated per kWh capacity cost for the CPPP.

iv. Hourly Pricing Program

Traditionally, large commercial and industrial customers have been served under more complex rate structures that provide greater opportunities for customers to reduce electricity charges. In recent years, industry participants have debated whether, in a restructured electricity market, the rate structure underlying provision of commodity service by a utility should be real time (or hourly) pricing. Certain jurisdictions require that larger customers be billed pursuant to a tariff or rate structure that charges for electric use with hourly market prices. For example, National Grid's affiliate in New York bills its large customers of 500 kW and above on a mandatory hourly pricing program. Customers in this program are charged the locational day-ahead hourly energy price from the New York Independent System Operator plus a capacity adder.

Within Smart Grid Pricing, National Grid proposes to place certain large general service customers on Standard Offer Service onto its Hourly Pricing Program. Those customers may elect to opt-out of this program under the same rules as described for CPPP above. Also, these customers will be protected from any total bill increases on an annual basis in the same manner as CPPP customers.

Similar to its upstate New York program, National Grid will send HPP customers the Day Ahead Location Based Hourly Energy Price ("DALHEP") plus an allocated capacity charge, if appropriate. HPP customers may need time to adjust to higher prices, therefore a price signal sent the day before should provide customers with enough time to prepare their response. A critical element of the hourly price is the per kWh capacity charge for each hour. National Grid proposes to include the same capacity adder for HPP that it uses for CPPP rates for each hour within a Critical Peak Event.

E. Reconciliation of Smart Grid Pricing

The design of the rates in Smart Grid Pricing may result in differences between revenue billed and costs incurred for Standard Offer Service. These customers will continue to receive Standard Offer Service and their load will be procured along with all Standard Offer Service load through the contracts with wholesale suppliers. However, the calculations used to design the Smart Grid Pricing are more complex and rely more on historical loads, which further removes the actual commodity rates charged to customers from the manner by which the costs are incurred by the Company. Thus, it is possible that an over- or under-collection of Standard Offer Service costs may be incurred from this small group of Pilot customers.

The Company proposes to include the Standard Offer Service revenue generated from the rates contained in the Smart Grid Pricing rate structure with all other Standard Offer Service revenue. Standard Offer Service supply costs applicable to the Pilot will be embedded in the invoices from the Company's wholesale suppliers; therefore including the revenue billed from Smart Grid Pricing represents the proper matching of revenue and expense.

F. Cost Recovery

National Grid believes that investment in Smart Grid technology is in the best interest of customers. National Grid is willing to make this investment, as outlined in the proposal, provided that the Commission sets rates that permit the Company to recover its costs in a timely manner and earn a return on investment reflective of the significant increase in Company investment that this plan represents. This recovery is authorized in the 2008 "Act Relating to Public Utilities and Carriers – Renewable Energy Standard," which provides that "…[t]he electric and gas distribution company shall also be authorized to propose and implement smart metering and smart grid demonstration projects in Rhode Island, subject to review and approval of the Commission, in order to determine the effectiveness of such new technologies for reducing and managing energy consumption, and include the costs of such demonstration projects in distribution rates to electric customers to the extent the project pertains to electricity usage and in distribution rates to gas customers to the extent the project pertains to gas usage." R.I.G.L. § 39-26-6(k). This program is also subject to National Grid's internal review and approval process, which is occurring concurrently with the Commission's review

The scope and size of the eventual Smart Grid program will be dependent on disbursement of and specific accounting and taxes associated with DOE grants awarded to National Grid and the remaining costs to be recovered from ratepayers. The Company intends to apply for ARRA funding for the Smart Grid Pilot Program under the Smart Grid Investment Grant (SGIG)

Program, as authorized by Title XIII, Section 1306. The Company intends to apply for matching funding for 50% of "eligible" costs as defined by the SGIG.

In order to recover the incremental funding needed for the costs of stimulus projects after taking into account DOE grant awards, the Company proposes a surcharge on customers' electric distribution bills based on a forward-looking mechanism that will track and reconcile to actual incurred costs for Smart Grid projects for concurrent recovery of investment and O&M expense. The Company proposes concurrent recovery of the revenue requirement associated with these investments, including annual operating expenses and return on rate base inclusive of construction work in progress (CWIP), at the Company's approved weighted average cost of capital (WACC), through a surcharge applied to customer bills. The costs eligible for recovery will include capital costs related to metering and communications technologies as well as software and, if required, dedicated hardware and a return thereon. Incremental operation, maintenance and customer education costs shall also be recovered. As the Commission is aware, financial markets are very volatile during this period and further investment may require additional financing.

Any level of assurance that can be ordered by the Commission will make National Grid's ability to fund these investments less expensive for customers. An order from the Commission which allows recovery of costs as incurred will promote the appropriate level of assurance to the financial markets that the investment will be recovered on a timely basis. The Company's ability to access the lowest cost funds offered by financial markets will be dependent on clear support from the Commission for recovery of these investments and expenses in real-time, without a lag.

National Grid also requests assurance that if these assets are abandoned for reasons beyond the control of the Company or otherwise rendered obsolete or no longer necessary beyond the demonstration phase, recovery of investments incurred or committed and not cancelable and abandoned are recoverable over an appropriate timeframe. The Company believes a policy and support for this treatment will be perceived positively by the financial marketplace, allowing attractive capital costs.

National Grid proposes to establish a tracking mechanism to forecast annual operating and capital costs which would determine the increment to be added to the surcharge. At least annually, forecasted costs would be reconciled with actual costs and any refund due or incremental recovery from customers would be incorporated in the next rate year's surcharge along with the relevant forecasted operating and capital costs through a "carry-forward" mechanism to reflect under- or over-spending in any one year against the targets set for subsequent years and any difference in actual surcharge collection versus forecasted surcharge revenues.

The Company will file comprehensive cost recovery tariffs at a future date based on the outcome of the SGIG application at DOE and the definitive costs that result from the vendor process described in this filing.

IV. SMART GRID TECHNOLOGY

A. Guiding Principles

In developing the Pilot and its broader Smart Grid plans, National Grid sought to develop a solution that:

- is aligned to Customer needs – both current and anticipated;
- satisfies the Smart Grid requirements of the Energy Independence and Security Act of 2007 as modified by the American Recovery and Reinvestment Act of 2009;
- aligns with National Grid Information System Technology Standards;
- leverages existing National Grid IS assets to the largest extent practicable;
- features a communications infrastructure that meets the requirements of advanced metering, customer choice/control and grid monitoring / control;
- uses standard communication protocols that support assigning unique addresses to individual devices;
- complies with current cyber security requirements and is capable of adapting to future requirements as they evolve;
- has an integration architecture that incorporates the IEC 61968 and IEC 61970 Common Information Model and reference interfaces;
- is interoperable with existing technologies and will interoperate with future technology enhancements;
- is flexible enough to accommodate varied vendor products to ensure competition and choice; and
- Enables common end-to-end business processes that are as independent of field technologies as possible, enabling consistent processes to be maintained with changes in technology.

B. Technology Principles

i. Inter-operability.

National Grid is employing industry standard technologies and practices as guiding principles during design and implementation. National Grid is pursuing interoperability between the three major elements, grid, meter, and home. This translates to using a non-proprietary and standards-

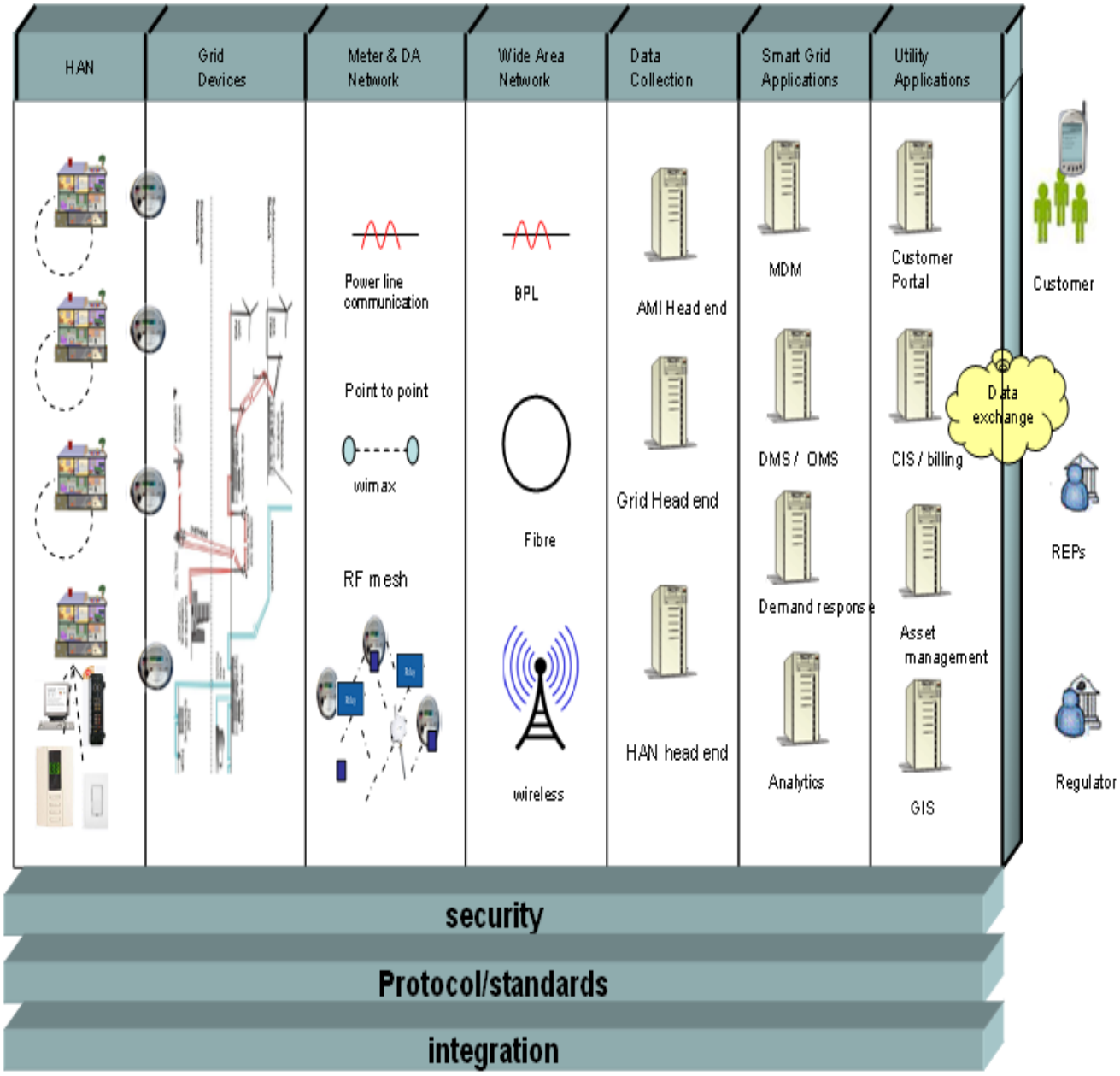
based approach to deliver an open architecture that can quickly and very easily integrate various vendor solutions into a single cohesive solution. This approach enables the widest possible technology and vendor choice for in-home devices and for our own enterprise systems. It also is consistent with FERC Interoperability and Stranded Costs guidelines noted earlier.

ii. Multi-tier Architecture.

The solution utilizes a multi-layered component based architecture platform that addresses the demanding performance and scalability requirements for the project. A multi-layered architecture enables logical separation (de-linking) of the various solution components making it easier to surgically replace or upgrade legacy components and add new components. It will consist of metering devices, network infrastructure (Home Area Network/LAN/WAN), client servers/machines, web server(s), application server(s), database server(s) and network storage.

This multi-tier approach organizes major components into Service Layers. These Service Layers act as both a common reference for all vendors of a particular function and offer a common view across all components of the overall solution. This approach creates a common evaluation process and ensures Service Layer interoperability.

The figure below represents the various Service Layers.



iii. Commercial-off-the-shelf ("COTS").

National Grid will leverage vendor strengths and competencies in choosing COTS products as opposed to developing in-house solutions. There are numerous advantages to this approach including:

- Selected products and applications have already been tested and proven in other utilities:
  - less risk;
  - lower cost;
  - faster time-to-market; and
  - More robust enhancements as these technologies continue to mature in support of a wider market share.

C. Scalability and Flexibility

Each service layer and associated product, and the overall Smart Grid system, can scale as the number of customers increases from pilot to full deployment. The overall architecture design will enable rapid changes in business needs, such as meter reading software and processes, if Rhode Island decides to move to a full deployment.

As business processes change and volumes increase, it is important for each product in each service layer to independently change without significant impact to business or other components of the solution. The multi-layered architecture satisfies these requirements without significant impact to other processes in the solution.

D. Leveraging Existing Systems

Some of National Grid's legacy systems will have to be upgraded or replaced as the project develops. National Grid will be able to use the same open, interoperable, multi-tier, scalable designs that we are using for all other Smart applications and products. A more detailed assessment of the systems can be found in Attachment 8.

E. Smart Grid – Request for Information

Through a recent RFI process, National Grid has sought to obtain the most current information on Smart Grid technologies, services, and pricing. This process familiarized National Grid's Program team with the capabilities and limitations of key technologies and helped identify those

technologies and services that may be utilized during the Program. Through this extensive procurement process we have identified multiple providers in each aspect of the proposed solution and we are ready to further negotiations and enter contracts once we receive regulatory approval. Details of the RFI process and its outcome are provided in Attachment 9.

F. Future Outlook

The technology vision also recognizes that the market is continuing to develop. As National Grid overlays a robust communications backbone along the electric grid and extends it into the customers' homes or business, new products and services will rapidly emerge. National Grid is selecting products for this backbone that will allow growth. By designing an open, interoperable system, National Grid reduces the risk of obsolescence while increasing the potential for rapid introduction of innovation with minimal disruption.

V. TECHNOLOGY SOLUTION

The Program's proposed Smart Grid technology solution will provide customers with ready access to more detailed and timely consumption information, timely energy cost and pricing options, greater choice, and simple, automated consumption controls. The technology solution and the new business processes that it enables will provide distribution grid operators and managers a powerful new set of tools to improve the efficiency, reliability and security of the grid. The Smart Grid technology will serve as the foundation for the Clean Energy Modules, including distributed generation, remote energy storage, plug-in hybrid electric vehicles and the next generation of renewable generation.

At the heart of the Smart Grid technology solution is a two-way communication system with the security, capacity and speed to enable advanced metering, new service offerings for customers that improve choice, control and convenience, distribution grid monitoring and control as well as the addition of Clean Energy Modules. Existing meters will be replaced with advanced digital smart meters. These meters are critical to providing the interval consumption data required to enable customer choice, control and convenience. They also provide a variety of data elements required to support distribution grid monitoring.

In addition, in-home energy management technologies will be made available to customers who choose to use them. These technologies will be organized from simple home display units to more complex and interactive automation software, programmable communicating thermostats, and communicating appliance disconnect devices. With these technologies, customers will be able to view their energy consumption and cost in near real-time, learn about and evaluate alternatives for reducing their energy consumption and expenditures, automatically control

electrical loads in their homes and, if they choose to, allow the electrical system operator to control certain in-home devices during critical system load reduction events.

The distribution feeders that provide electricity to customers in the pilot area will be updated to include sensors to monitor critical operating parameters and control equipment that can sense abnormal conditions on the grid and allow the grid to be reconfigured. All of the technologies installed on the distribution grid will communicate with a new network management system in the grid operating centers. This network management system will enable grid operators to view the status of the grid in near real-time, identify abnormal operating conditions, evaluate available corrective actions and take remote action to reconfigure the distribution grid to avoid or minimize the scope and duration of outages, and improve voltage regulation and power quality. In addition, the grid operating data gathered and recorded by Smart Grid-enabled sensors will guide future grid investments by identifying specific grid enhancements that will reduce unplanned outages and generally improve power quality.

The Smart Grid technologies proposed for the Pilot will enable the addition of distributed resources, including renewable generation, energy storage and plug in hybrid electric vehicles, by allowing all of these resources to be interconnected with the grid in a carefully managed process that does not overwhelm and destabilize the grid as the number and types of these resources increases over time.

A. Communications Technology

Smart Grid systems will rely on a robust, two-way communications platform to effectuate reliable and secure transfer of data. The general architecture will be the development of neighborhood collectors that will act as access points for home meters and some grid devices. Collectors will in turn communicate with a wide area infrastructure that will leverage existing National Grid assets, new wireless technologies, and public networks where appropriate to communicate between field collectors and grid devices and utility operators and computer systems.

The goal is to have the same infrastructure support both customer and grid device communications. The preferred solution is a private infrastructure committed solely to the smart enablement, but the reality of our service territory and the cost to construct a dedicated network from home to utility makes the use of some public network transport necessary.

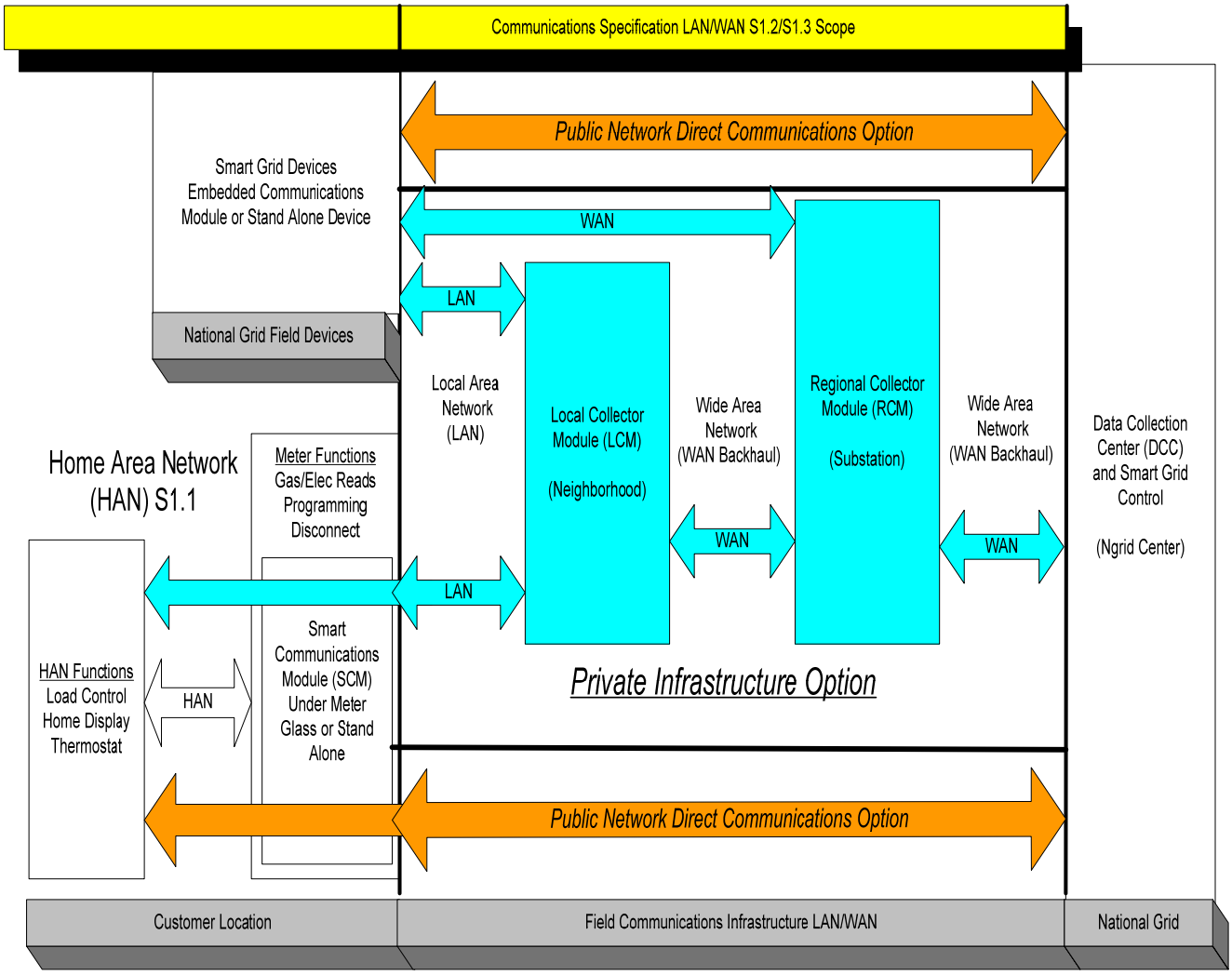
The meter will serve as the communications portal into the customer home. This approach makes available a certain level of communications capability to all customers and will place the responsibility for operations of that infrastructure on National Grid. For those customers who

opt for the most robust in-home energy management tools, interaction with home devices and in-depth consumption data will be managed via a customer-provided broadband internet connection. In this scenario, the customer's existing broadband router will be the interface point to new high bandwidth, low latency in-home devices that enable this more robust and automated energy management. As new vendor offerings become available, they will be evaluated and made available as appropriate.

That network is composed of the following major elements:

- Wide Area Network ("WAN") – The WAN enables communication between regional collection points and the utility operating center and back office. Communications to and from multiple meters and intelligent electronic devices ("IEDs") are routed through regional collection points located throughout the pilot area.
- Local Area Network ("LAN") – The LAN enables direct communications between individual smart meters and IEDs and between individual devices and regional collection points.
- Home Area Network ("HAN") – The HAN enables communications between the meter and IEDs installed within a customer's home or business.

A graphic depiction of the proposed communications network is shown below.



Smart Telecommunications System Options

The WAN will be designed and constructed, where required, using a combination of proven fiber optic, microwave and WiMax technologies. Existing National Grid assets will be incorporated into the Smart Grid WAN to the largest extent practical with some degree of reliance on public networks where practical.

The LAN will be a two-way radio frequency mesh network. Installed meters and grid sensors will self-discover and register on the network when electrical power is applied to them. The HAN will be a wireless network that uses the ZigBee Smart Energy Profile embedded in the

meter to manage the exchange of interval usage, price signals, controls as appropriate, and other meter or customer information from the utility to customers and from customers to the utility.

Within a customer's home or business, a variety of communication protocols will be evaluated to determine their strengths, weaknesses and appliance-level application for in-home communications. These protocols will include ZigBee from the meter direct to the in-home devices and Insteon and Smart Plug with a bridge relay between the devices and the meter. Attachment 10 provides additional information on the smart communications.

B. Smart Metering

National Grid proposes using advanced metering technologies in the pilot that enable the meter to be a smart consumption measurement device and an important Smart Grid sensing device. The meter will measure and report total consumption, interval consumption, demand, energy supplied by the grid, energy provided to the grid, voltage and power factors. It will also be able to log and trigger communications to alert the operator to specific occurrences such as tampering, outages, and meter/load problems.

C. In-Home Energy Management

The in-home energy management technologies are designed to allow customers to participate at multiple levels. At each level of participation customers are provided with energy consumption and pricing to inform their decision making and process. As customers elect to become more engaged, the information and tools available to them to actively manage their energy consumption and usage become increasingly detailed, timely and interactive, with more options and greater flexibility for the customer.

Three levels of in-home energy management technology will be provided to customers based upon the service offerings in which they elect to participate. No in-home technology will be provided for customers who elect not to participate in energy management programs, although they will still be able to participate in the Smart Grid project via new tariffs.

- Level 1 In-Home Technology consisting of a home display unit will be provided for those customers who select a minimum level of involvement in energy management programs. The base model home display unit will provide customers with basic consumption information from the meter and informational messages from National Grid.

- Level 2 in-home technologies will consist of a home display unit and two (2) in-home control devices, either programmable communicating thermostats and / or direct load control devices. In addition to basic in-home display functionality, in-home technology

in this level will allow customers to enroll in a direct load control program that allows National Grid to control thermostat settings and disconnect loads in a customer's home or business during system critical peak events.

- Level 3 in-home technology will consist of a web- and / or mobile device-enabled set of tools that allow customers to; 1) receive targeted educational content from National Grid via written, audio or video media to inform them about techniques that they can employ to reduce their energy consumption; 2) model and track the impact of various actions on their energy consumption and expenditure; 3) interactively control individual loads in their homes or businesses; 4) add additional load control devices to their home or business accounts; and 5) establish time-of-day and of-week load control profiles that automatically control loads in their homes or businesses to reduce their energy consumption every day of the year, not just on system critical peak days.

D. Grid Monitoring and Automation Technology

The monitoring and control technology deployed on the distribution grid as part of the Program will work in concert with the communications and advanced metering technologies described above to improve the operating efficiency and reliability of the distribution grid, while at the same time providing the Smart Grid foundation necessary to enable greater numbers of distributed resources, such as renewable generation, battery storage units and PHEVs, to be added to the distribution grid safely and efficiently.

Six categories of technology are being deployed on the grid as part of the Program:

- First, new monitoring devices will be mounted directly on feeders. Feeder monitors will be installed at selected locations on each phase of three phase feeders to measure voltage, current and power factor on each phase. Faulted circuit indicators will be installed at selected locations to allow circuit faults to be recorded in order to identify the location and nature of circuit faults. Distribution transformer monitors will be installed on approximately two thirds of the distribution transformers in the Program area. These devices measure secondary voltage, current and power factor on each.
- Second, retrofit communication devices will be installed on existing grid control and switching equipment to enable this equipment to be monitored and controlled remotely. Existing recloser and capacitor bank controllers capable of supporting communications will be upgraded to add this capability to allow remote monitoring and control of reclosers and capacitor banks. Existing recloser and capacitor bank controllers that cannot be upgraded will be replaced with new controllers that include remote monitoring and control capabilities.
- Third, new grid control and switching equipment will be added to feeders in the Program areas. This new equipment includes reclosers, capacitor banks, automated tie switches

and automated load-break switches. This new equipment will have remote monitoring and control capabilities. New automated tie and load-break switches will have local protection and control logic that can be programmed remotely and their autonomous operation requires the inclusion of peer-to-peer communications capability.

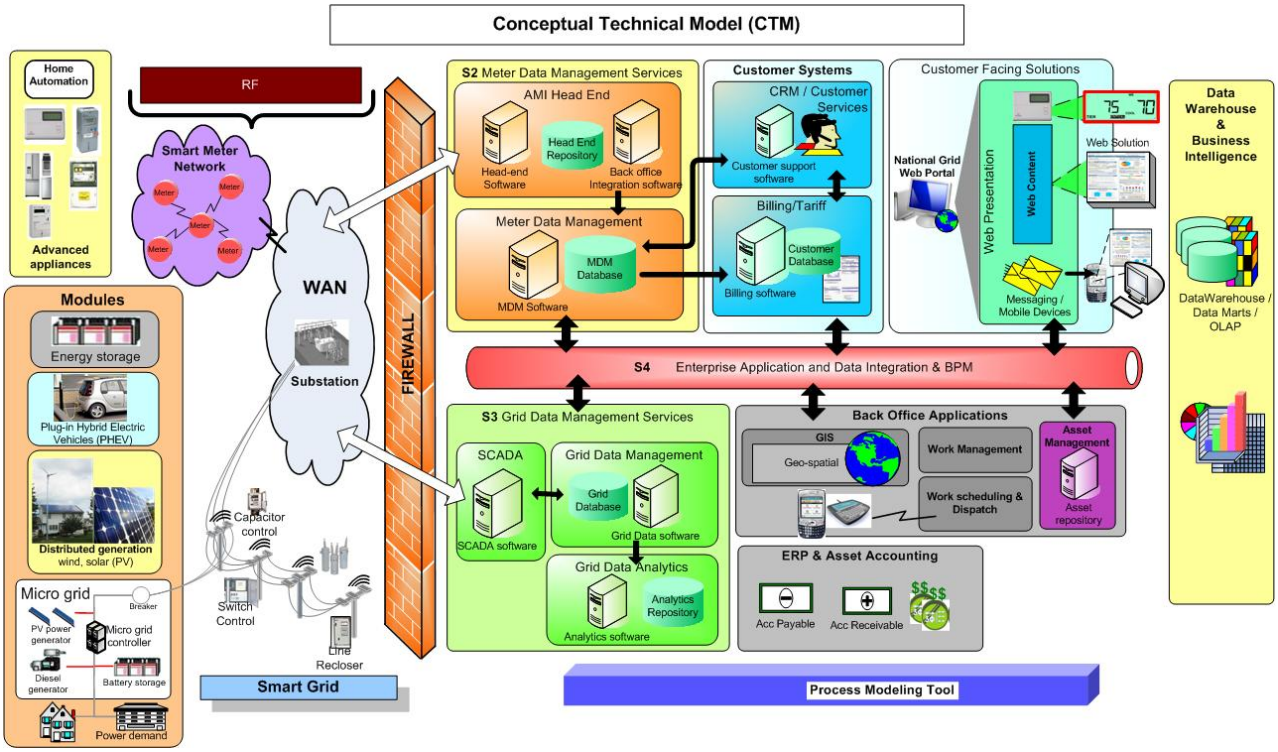
- Fourth, software applications deployed for the Program now include both digital Outage Management System (OMS) and Distribution Management System (DMS). ARRA funding guidelines now appear to explicitly support these systems and their inclusion will significantly enhance the value of the data that will flow from the new smart endpoints. Benefits include:
  - allow distribution grid operators improved visibility into the operating conditions on the grid;
  - enable operators to evaluate alternative switching scenarios in near real time to enable improved decision making;
  - enable operators to identify, locate and determine the scope of outages and other problems more quickly;
  - enable operators to control grid equipment remotely to reconfigure the grid to avoid outages and minimize the scope and duration of outages;
  - optimize the control of voltage and power factor on the grid to reduce losses;
  - enable modeling of the impact that interconnection of renewable generation and other distributed resources in increasing quantities will have on the operation of the distribution grid;
  - enable the development and implementation of new dispatch and control programs for distributed energy resources; and
  - Identify changes in the operation of grid equipment to flag developing problems, so that they can be resolved before the equipment fails.

- Fifth, addition of substation EMS/SCADA at select substations where this technology does not exist today. The upgraded substations will provide an expanded, real-time view of the area and enhance the value of the distribution- level smart grid data, by including substation performance data, which is a fundamental piece of information on the overall distribution function.

- Sixth, addition of digital monitoring and control breakers in Subtransmission stations in the area of the smart deployment to support full grid automation. The circuit breakers identified for replacement are older breakers of obsolescent technology. They need to be replaced to ensure appropriate protection for the area covered by the Smart Grid program.

VI. SMART GRID INFORMATION SYSTEM SOLUTION

The delivery of an IS Solution for the Pilot will impact the existing applications and also introduce new applications to the existing National Grid IS landscape. Application integration forms a critical part for an end-to-end technological solution because a majority of the applications that comprise the IS Solution will be involved either in sharing data or connecting processes. As this technical model below indicates, there are a number of systems that must work seamlessly with each other for the Smart Grid to function. Additional details on the Information System solution for the pilot are provided in Attachment 11 Information Systems Summary.



New applications were identified during the vendor evaluation sessions for each specific service layer within the Technical Model:

A. New Applications

Service Layer	Activity/Function	Technology/Software
S1 – HAN / LAN / WAN	Communications	• RF Mesh • Fiber-optic, microware, Wi-Max
S2 – Meter Data Management Services	AMI Meter Head end	• Head end software • Back office integration software
	Meter Data Management	• Meter Data Management
Customer Billing	Customer Billing	• Billing software
S3 – Grid Data Management Services	• GRID Head end • DMS & Grid Analytics	• SCADA software and repository
	• Grid Analytics	• Analytics software
S4 – Enterprise Integration and BPM	Middleware	• EAI and BPM tool
S5 – Web solution S6 – Messaging S7 – Mobile Devices	• Home Automation Head end • Web Presentation • Messaging & Mobile Services	• Customer-facing energy conservation tool
Data Warehouse & Business Intelligence	Business KPIs and Metrics	• Data Warehouse • Reporting and Metrics tools
Process Modeling	Process modeling	• Process modeling software

B. Existing Applications

In addition to installation, integration and testing new applications, some work will be required to modify the existing legacy applications to support the new business processes and the new applications for the Pilot. If a decision is made to conduct a full rollout of Smart Grid to all customers, the existing legacy systems may not be suitable for that larger deployment. Analysis has been conducted to define the present state, the desired or target state and the gap between them for the Pilot, as presented in Attachment 10.

C. Data Impacts

Piloting new Smart Grid services will impact both the flow and the volume of data that must be exchanged and processed within IS. Data impacts have been modeled based on the envisioned future state of the information system needed to meet the Smart Grid objectives and includes the data subject areas from the current systems and future subject areas that will form the end solution. This information is gathered based on discussions with National Grid IS and business teams and through vendor discussions for the Smart project. Also industry standard methodologies and data modeling best practices were used to create the data model. See Attachment 12, High Level Data Model.

D. Integration

National Grid will use an Enterprise Service Bus ("ESB") / Business Process Management ("BPM") integration strategy to support its pilot roll out. The ESB unifies message-oriented, event-driven and service-oriented approaches for integrating applications and services. BPM helps redefine and improve existing business processes. The ESB will be a core part of the system and will be the central transport and interface mechanism for all related systems. The ESB component includes substantial work to implement a robust, fully fault tolerant bus-based architecture and industry standard messaging design.

The BPM will be able to constantly capture and track sub-second real-time information on the processes that it is managing, and it will also be able to monitor and track a broad variety of events. The BPM will be scalable, multi-platform, multilingual and middleware-agnostic.

Existing interfaces used as part of the technical solution will remain as point-to-point interfaces. Attachment 13, Integration Outline, provides additional information.

E. Hardware and Software Specifications

National Grid's vendor evaluation workshop sessions evaluated vendor responses for each service layer by Subject-Matter experts ("SME") to determine the best option for the IS and Communications Smart Solution. The hardware and software specifications will require further analysis as the final technology solutions are matched against the Pilot objectives. Attachment 14, Hardware and Software Specification, provides additional details

F. Security

As noted earlier, a key element in the evolution of the Smart Grid is the convergence of the electrical power infrastructure, communications infrastructure, and the supporting information

system infrastructure. The security framework that addresses these must take into consideration the needs of all parties. National Grid will integrate various existing networks, systems, and touch-points that are capable of exchanging information seamlessly. The older proprietary and often manual methods of securing utility services will disappear as each is replaced by more open, automated and networked solutions.

Some of the unique security challenges of the Smart Grid include:

- Smart Metering and Home Automation touch every customer
- Smart Metering and Smart Grid solutions are "command and control" systems
- Millions of controllable end-points will be added along the infrastructure
- Almost every enterprise system will be impacted

As noted earlier, National Grid has a robust plan to address security. The following high level security objectives provide further insight into the key objective of that program:

- Availability: avoid denial of service
- Integrity: avoid unauthorized modification
- Confidentiality: avoid disclosure
- Authenticity: avoid spoofing/forgery
- Access control: avoid unauthorized usage
- Audit ability: avoid undetected access
- Accountability: avoid denial of responsibility
- Third party protection: avoid attacks on others

A detailed Security Framework can be found in Attachment 15 hereto.

VII. SMART GRID FINANCIALS

The preliminary analysis for the Pilot projects a $59 million operating and capital expenditure requirement. The breakout of this total expenditure by category is as follows:

	Rhode Island Pilot		
Expenditure Category	Expenditure	$ per Meter	% Expenditure
In-Home Capital	[redacted]		
Electric Meter Capital			
Summary Gas Meter Capital			
Communications Technology Capital			
IT Systems Capital			
DMS OMS			
DA Capital			
Clean Energy Modules			
Other Program Elements Capital			
Total Capital			
Marketing Expense			
Power Operating Expense			
IT Operating Expense			
DMS OMS Operating Expense			
Clean Energy Module Operating Expense			
Backhaul Related Operating Expense			
Total Operating Expense			
Total Capital and Operating Expense	$ 59,294,316	$ 5,845	100%

VIII. DEPLOYMENT PLAN

This section describes the timeline and deployment plan National Grid proposes for the Smart Grid Pilot. In addition to implementing the Pilot itself, the project team's mission expressly includes working with any affected department or business unit within the company to define any new business processes or changes to existing processes required to support the Pilot, as well as training the appropriate National Grid personnel in the new solution.

A. Project Planning

The Pilot team evaluated several alternative approaches for implementing a Smart Grid pilot, adopting best practices from similar projects at other utilities. The overall approach selected by the team is an "Integrated Functional Release" strategy in which National Grid implements key technology and enables associated functions in phases, each called a Release, building complexity and allowing National Grid to progressively enable, test and adapt to new Smart Grid technologies and business processes. For example, Release One will test smart meter communications in the field on a limited number of residences while continuing to use existing meter reading and billing processes. This will permit field testing of smart metering capabilities without potentially disrupting customers' monthly bills. Plans for each functional release are described below.

Smart Grid will fundamentally change many aspects of National Grid's business, making necessary and possible a greater degree of integration and increasing the exchange of information between business units and supporting computer systems. The Pilot project team will take an integrated and comprehensive approach, and will include key participants from all affected areas of the business. A core group of the project team will focus throughout the Pilot deployment and beyond on refinements and adjustments, particularly as Smart Grid technologies change and evolve.

B. Deployment Timeline

The following table provides an overview of key milestones for the proposed Program. For illustrative purposes, the chart below shows Month 0 as the Project start date. It is assumed that National Grid has regulatory approval, the vendor equipment has met all internal safety and standards testing, vendor contracts have been signed and DOE contributions have been secured.

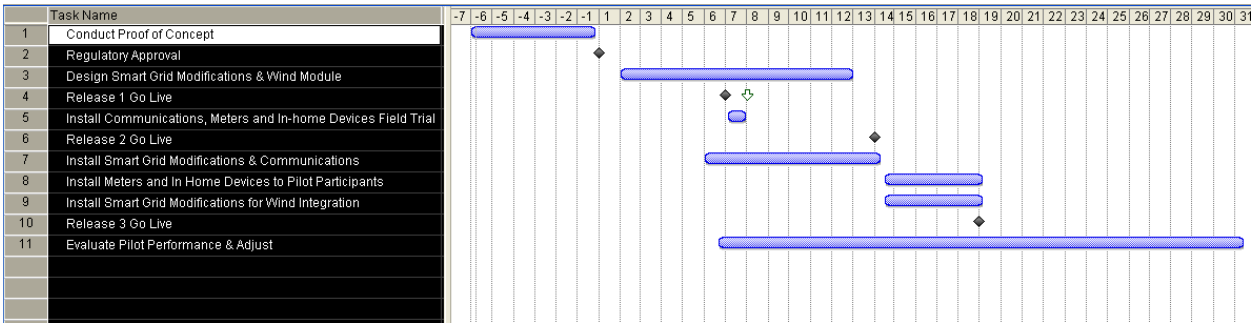
Phase /Release		**Customer Capabilities Introduced**	**National Grid Capabilities**	**Phase Activities / Release Functionality**
Proof Of Concept	Pre – Month 0		• Smart technologies lab	• Technical Proof of Concept • Integrated requirements and logical design workshops in key business areas
Regulatory Approval	Month 0			Regulatory Approval
Advance Procurement	Month 1 - Month 4		• Early order of equipment	• Meters & communications • PHEVs • Energy Storage • PV
Release 1	Month 7	• Selected customers participate in field trials of smart services and technologies	• Field testing of Smart Meters and communications • Interval meter reading and testing • Analysis and Design for Modules	• 250 Meters are installed (dual socket) at selected customer's premises • Retain current AMR meter reading process • Meter Head End Communication • Basic Functionality Meter Data Management (MDM) • Initial Communications Network
Release 2	Month 12	• Electric consumption information available on Home	• Updated processes and systems to support Smart	• More MDM Functionality including Integration

		Display • Education on smart programs and consumption	Services deployment and installation • Interval meter reading used for billing • Automatic outage notification • Ability to verify customer outage and restoration •	with Current Billing • Field Deployment Processes and Tools • Basic Home Automation (Limited Info on Home Display) • Device Life-Cycle Management for Communications, Meter, and Grid • Basic Grid Operations (OMS, EMS) • Expansion of Communication Network • Begin Initial Benefits Measures •
Grid Modifications Syracuse	Month 1 – Month 23		• Grid devices installed • Monitor distribution grid operation	• Grid Automation and Monitoring Construction Complete for Program
Meter and In-Home Device Deployments Syracuse	Month 14 – Month 23		• Smart meters installed • In Home devices installed	Beginning in approximately Month 14, meter replacements would begin to ramp up in Pilot Area until ~10,000 Smart Meters are installed. • Month 1 - 500 • Month 2 - 1000 • Month 3 – and beyond 5000per Mo.

Module Installations Syracuse	Month 17 – Month 27	• PHEV • Large customer micro-grid	• Energy Storage • PV	• The installation of Smart Modules will be installed in parallel with the installation of the common communications infrastructure required to support Smart Customer and Grid facing services
Grid Modifications Capital District	Month 12 – Month 25		• Grid devices installed • Monitor distribution grid operation	• Grid Automation and Monitoring Construction Complete for Program
Meter and In-Home Device Deployments Capital District	Month 16 – Month 25		• Smart meters installed • In Home devices installed	• Beginning in approximately Month 16, meter replacements would begin and ramp up in the Pilot Area until ~ 10,000 Smart Meters are installed.
Grid Construction	Month 13-18	• Wind and Storage Integration		• Integration of Wind and Storage into existing grid operation
Release 3	Month 18	• New rate / customer programs • Smart service information available through various means • Education on smart programs and consumption	• Updated processes to support smart service programs (enrollment through billing) • Two-way communication with smart	• Customer Portal / Mobile Device Capability • Complex Billing and Complex Rates to support new Smart Service

			meters • Detailed analytics and reports • Fully deployed monitoring and remote control of grid equipment • Automated outage detection and isolation • Automated voltage control	Products • Full Home Automation • Initial Data Warehouse, including Reporting and Analytics • Initial Demand Response • Load Monitoring • Expansion of Communication Network Operations • Full Grid Operations (DMS, OMS)
Operate Program	Month 13 – Month 51			• For analytical purposes, the Program location grid and customers are measured and monitored for 24 months after commissioning of all assets. This can be adjusted.

A graphical depiction of this preliminary timeline is shown below.



C. Description of Release Phases

i. Proof of Concept

During this pre-release Proof of Concept phase, key Smart Grid technologies are being deployed in a laboratory environment in a coordinated process with the vendors. This lab environment will enable National Grid to test components of the proposed Pilot solution from a technical and functional perspective to confirm expectations and to assess component compatibility. Functional test cases, derived from the Company's business requirements, will be developed and tested during this phase. For example, demand response event messages to the customer will allow the team to observe and confirm or alter key processes and functions. During the proof of concept phase, the technologies are only being tested with standard capabilities and some simulation of automated integration.

ii. Release One

The objective of the first release is to test communications and smart meters in the field while continuing the parallel billing process with legacy systems. This parallel process enables us to learn from field deployments without exposing the customer to the potential problems associated with any learning process. Approximately 250 customers, located on the same distribution circuit, will have a Smart Meter installed next to their existing AMR meter. Testing in this phase will cover the communications network for the selected substation, the meter head end and the basic functionality of the meter data management system ("MDMS") at the utility. These systems will support communications testing with smart meters and the collection of interval meter reads. These tests will confirm reliability of communications and accuracy of remote meter readings prior to using the Smart technology for customer billing. Implementing a best practice learned from prior Smart Grid pilots by other utilities, the 250 customers selected for Release One testing will continue to be the core field testing group before future functionality is rolled out to the broader population served by the Pilot system.

iii. Release Two

Release Two includes functionality that will enable National Grid to deploy the remaining 9,500+ meters, fully replacing the existing AMR meters at those residences and businesses. Interval data will be recorded by the new smart meters and collected using the new head end and communications network. Billing will be performed using the current systems using total consumption data aggregated in the new MDMS. The field deployment team will also test new processes and systems to support smart meter replacements in the field, such as new processes to install and provide quality assurance as well as updates to the information systems to support the Smart Solutions such as work order, dispatch, asset management billing, etc. The pace of replacing existing meters with smart meters will progressively increase over a several-month period as National Grid identifies and resolves any issues in the logistics, installation, and

activation process. This approach will enable future large-scale deployment of smart meters to be managed efficiently. During the evaluation of other pilots, National Grid found that each field crew could install between forty and eighty meters a day, depending on a variety of variables. National Grid estimates that all Pilot smart meters will be installed over a four month period during Release Two. Additional functionality in Release Two will enable field testing of home display units, support for grid monitoring and testing. Our plan is to deploy a wireless communications network technology in parallel with smart meter installations.

iv. Release Three

Release Three will deliver the full range of capabilities planned for the Pilot. Customers will have the ability to monitor consumption on a home display unit or the Pilot web portal; establish energy saving modes to automatically control loads in their homes; and control and monitor load in their homes and businesses via mobile wireless devices. From the distribution grid perspective, Release Three will enable remote monitoring, voltage optimization, sectionalizing and automated outage detection and restoration planning and confirmation. This release will also enable smart grid embedded demand response. As of this phase, analytics and measurement for the full Pilot will be expanded and data will be compared against baselines established during prior releases.

D. Summary

Smart Grid deployments are extremely complex. National Grid will have to confirm the capabilities of new technology, make sure that new and legacy technologies work together, adapt the businesses processes, and educate employees and customers. In order to accomplish these deployments in a condensed time frame, the Pilot overlaps the functional releases and coordinates between the multiple parallel activities.

IX. CONTINGENCY PLAN

Smart Grid projects are composed of a large number of components provided by multiple suppliers. These components must work together seamlessly in order to provide the desired value to consumers, utilities, regulators, and the society at large. In addition, hardware, software and interoperability standards are still evolving. These kinds of projects by their nature are inherently risky. National Grid intends to actively manage the risks on the Smart Grid program. Active risk management on the project will include an ongoing assessment to identify risk events that may occur in the future, developing contingency plans to reduce the likelihood of these risk events occurring, minimizing the impact of risk events on the program should they occur and

dealing with them if they do occur. Several key risk areas have been identified. These, along with the contingency plan that addresses each, are summarized below:

Risk Event	Contingency Plan
Customers do not elect to become engaged in the Smart Services offered by National Grid.	In order to reduce the likelihood of this event occurring National Grid will undertake secondary market research as part of finalizing the design of its Smart Services offerings and marketing plan to assure that the services being offered are attractive to customers. Once the marketing and enrollment process begins, opt-out rates will be monitored weekly to identify unfavorable trends quickly so that contingency plans can be implemented quickly. Contingency plans will be developed in advance of the launch, marketing and enrollment. These contingency plans will include additional service elements and / or modifications to tariffs that can be introduced if necessary in order to improve customer sign-up rates.
Vendors are not able to deliver products to support the project schedule or the delivered products do not perform as specified.	This event is likely to occur to some degree. The contingency plan in place to deal with this situation includes: • Conducting a proof of concept to validate functionality and compatibility of the technologies that will be deployed. • Using technologies that utilize existing and evolving open standards to allow products from more than one vendor to be incorporated into the solution. • Phased approach for introducing new functionality to customers in a controlled manner that measures impact and manages exposure.
The Smart Grid Program is complex, involving a large number of	In order to reduce the likelihood of failure in each element of the Smart Grid Program, National Grid will: • Implement a proven Program and Project Management

Risk Event	Contingency Plan
customers, utility business functions and technology components. Failures in any one of these areas can adversely impact project results.	approach across all aspects of the program. • Contract with vendors and service providers experienced in the design, manufacturing and installation of Smart Solutions. • Make effectively managing the customer experience aspects of the Program a high priority.
Smart Grid Program is cancelled prior to its completion or a decision is made not to deploy the Smart Solution beyond the initial Program.	National Grid will include cancellation provisions in contracts with vendors and service providers engaged in delivering the Smart Program. If cancellation occurs after the installation of smart meters and home automation devices, provisions have been made to remove and replace this equipment with existing meter technology. Business process and information systems modified to accommodate the Program will be rolled back to pre-Program conditions.

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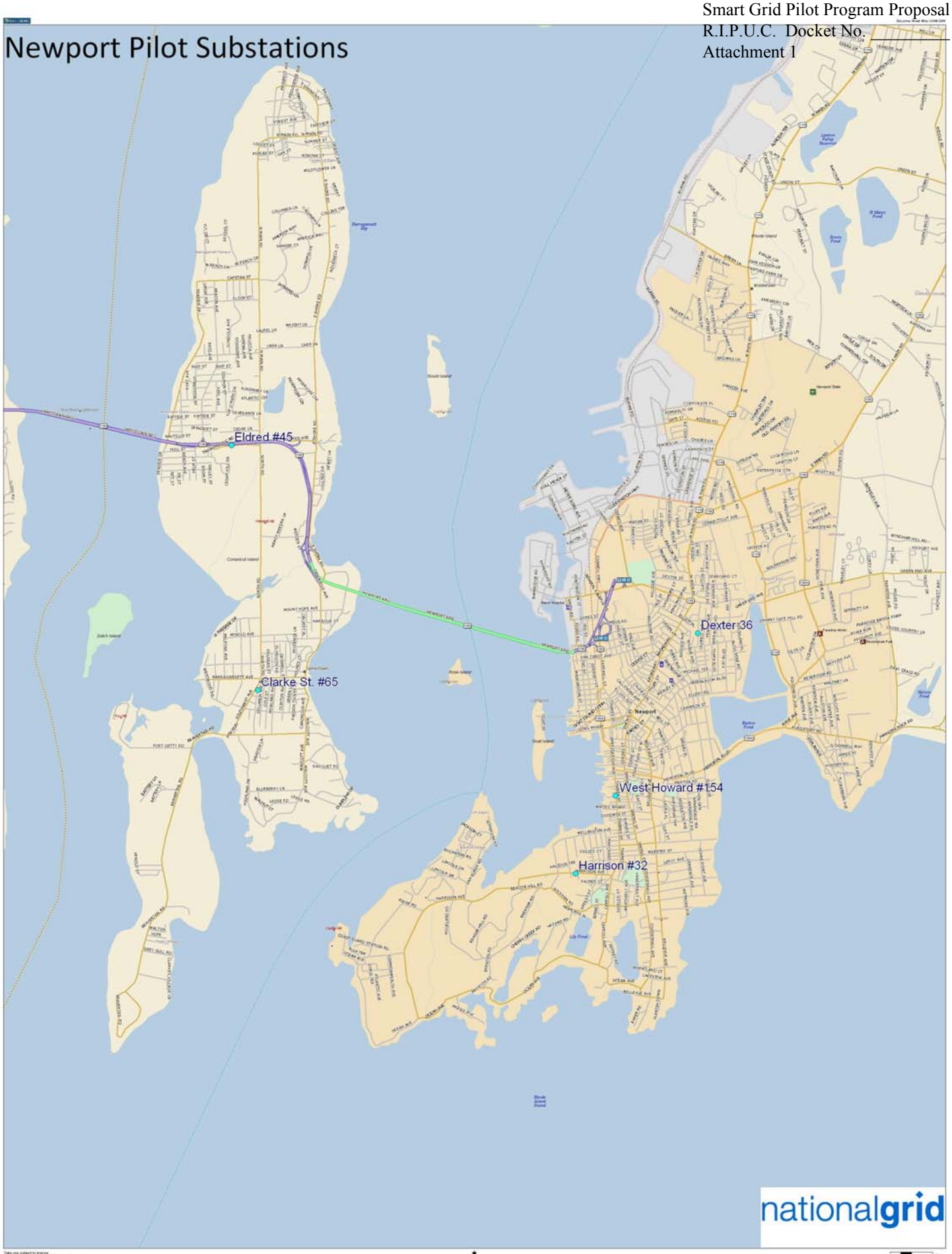
Attachment 1


Newport Pilot Substations
Eldred #45
Clarke St. #65
Dexter 36
West Howard #154
Harrison #32
nationalgrid

Attachment 2

Customers by Rate Class

Rate Code	Description	Customers
A-16	Basic Residential Rate	8,712
A-60	Low Income Residential Rate	165
C-06	Small C&I Rate	1,119
G-02	General C&I Rate	161
G-32	200 kW Demand C&I Rate	12
	Total	**10,169**

Attachment 3

Feeders, Customers, and Equipment Totals

Name	CDF	Customers	Residential	Commercial	Electric	Gas	Total_Xfmr_Count	OH_Xfmr_COUNT	UG_Xfmr_COUNT	Reclosers	Sectionalizers	Capacitors
West Howard	49_56_154 J2	229	92	137	229	-	45	30	15			3
West Howard	49_56_154 J4	79	-	79	79	-	16	-	16			
West Howard	49_56_154 J6	264	209	55	264	-	13	13	-			
West Howard	49_56_154 J8	706	567	139	706	-	85	69	16			3
Harrison	49_56_32J 2	908	848	60	908	-	124	76	48			9
Harrison	49_56_32J 4	684	641	43	684	-	119	55	64			3
Eldred	49_56_45J 2	658	643	15	658	-	111	97	14			3
Eldred	49_56_45J 4	541	502	39	541	-	170	139	31	1		9
Eldred	49_56_45J 6	461	445	16	461	-	99	74	25			3
Clark Street	49_56_65J 12	717	647	70	717	-	194	174	20			6
Clark Street	49_56_65J 2	845	688	157	845	-	171	156	15	2		6
Dexter	49_56_36 W41	2,060	1,813	247	2,060	-	306	257	49			24
Dexter	49_56_36 W44	1,993	1,732	261	1,993	-	427	320	107	1		15
Total		**10,145**	**8,827**	**1,318**	**10,145**	**-**	**1,880**	**1,460**	**420**	**4**	**-**	**84**

Attachment 4 is REDACTED in its entirety.

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Attachment 5

Marketing Plan Business Capabilities

#	Service	Business Capability
1	Level One	Real time measurement of consumption Communication of energy consumption Dynamic pricing
2	Level Two	Real time measurement of consumption Communication of energy consumption Automated load management Dynamic pricing

#	Service	Business Capability
3	Level Three 1st Generation 2nd Generation 3rd Generation	Real time measurement of consumption Communication of energy consumption Distributed energy management Automated load management Prepaid usage (optional)

Attachment 6

Marketing Plan Tactics

The Three Phases of the Marketing Approach can be found below:

I. Seed (Approval to Launch)	Communications reach targets: 1. Residents 2. Small Businesses 3. Community Leaders
• Meet with elected officials and community leaders	3
• Send “teaser” message to all pilot participants	1,2
• Engage “high profile” participants	1,2,3
• Initiate “SGV” contest	1,2
• Launch SmartSquad	1,2,3
• Develop press kit	1,2,3

II. Share	Communications reach targets: 1. Residents 2. Small Businesses 3. Community Leaders
• Distribute "Welcome Kit" to participants and community leaders	1,2,3
• Introduce participants to web overlay – profile, options, social networking	1,2
• Bill stuffers (monthly)	1,2
• Erect solar powered billboards highlighting consumption savings	1,2,3
• Launch e-newsletter	1,2
• Send direct mail to participants and community leaders	1,2,3
• Announce "Badges of Honor"	1,2
• Initiate contest	1,2,3
• Launch "Get Smart" breakfast series	1,2,3
• Launch In field demonstration unit	1,2
• Sponsor neighborhood block parties	1,2
• Launch "house" parties program	1
• Build school partnerships	1,3

III. Succeed	**Communications reach targets:** **1. Residents** **2. Small Businesses** **3. Community Leaders**
• Continually update web overlay	1,2
• Bill stuffers (monthly)	1,2
• Update solar powered billboards	1,2,3
• Garner PR coverage of “high profile” participant	1,2,3
• Send direct mail to participants and community leaders	1,2,3
• Update e-newsletter monthly	1,2
• Continue contests	1,2
• Continue school programs	1,3
• Continue utilizing in field demonstration unit	1,2,3
• Continue “house” parties program	1

Attachment 7

Attachment 7 is REDACTED in its entirety.

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Global SMART Services Development Program

Filing Exhibit – Impacted Systems

1. Purpose

The Gap Analysis consists of defining the present state, the desired or `target' state and determining the gap between them.

The purpose of the document is to capture and understand the gap that exists between the current state of applications within the National Grid IS Landscape and the 'To-Be' state these applications need to reach to support the Smart Program. The document will capture the changes required to existing applications to support the new business processes introduced as part of the Smart Solution

The results of this analysis were used as in input to developing the NY Smart Program proposal.

2. Scope

The scope of this document is to identify the effort required to modify the existing legacy applications only. This covers the changes required to support the Program and includes all Residential and small Commercial & Industrial customers.

NOT included within the scope of this document are:

- Efforts for customization to 3rd party applications
- Impacts of a full roll out on legacy systems/applications (this will need to be investigated further prior to any future roll out taking place)

3. Impacted Applications

3.1 Application Areas

The applications in question have been organized in line with the structure provided by the Global Transformation Program, using the 'Global Landscape 2008' Model as a Baseline. This represents a logical alignment with the Business Processes detailed within the Business Architecture document:

- System & Market Operations – All Distribution Grid Control applications such as OMS, DMS, etc
- Customer Management – Customer facing systems, such as Billing, Customer Calls and presentation of Customer Data. Meter Data collection is also included within this area
- Work & Asset Management - Work and Asset Management applications, including both Meter and Grid (via the GIS) Devices and Substation Equipment, in addition to all work in relation to the National Grid Mobile Workforce.
- Shared Services - Financial systems such as Procurement, Finance, Admin, etc.

3.2 Identifying the As-Is Systems

Due to the variety of systems/applications within National Grid, a structured approach was followed to identify only applications impacted by the Smart Program. From the initial 1,500+, these were narrowed down using the following approach:

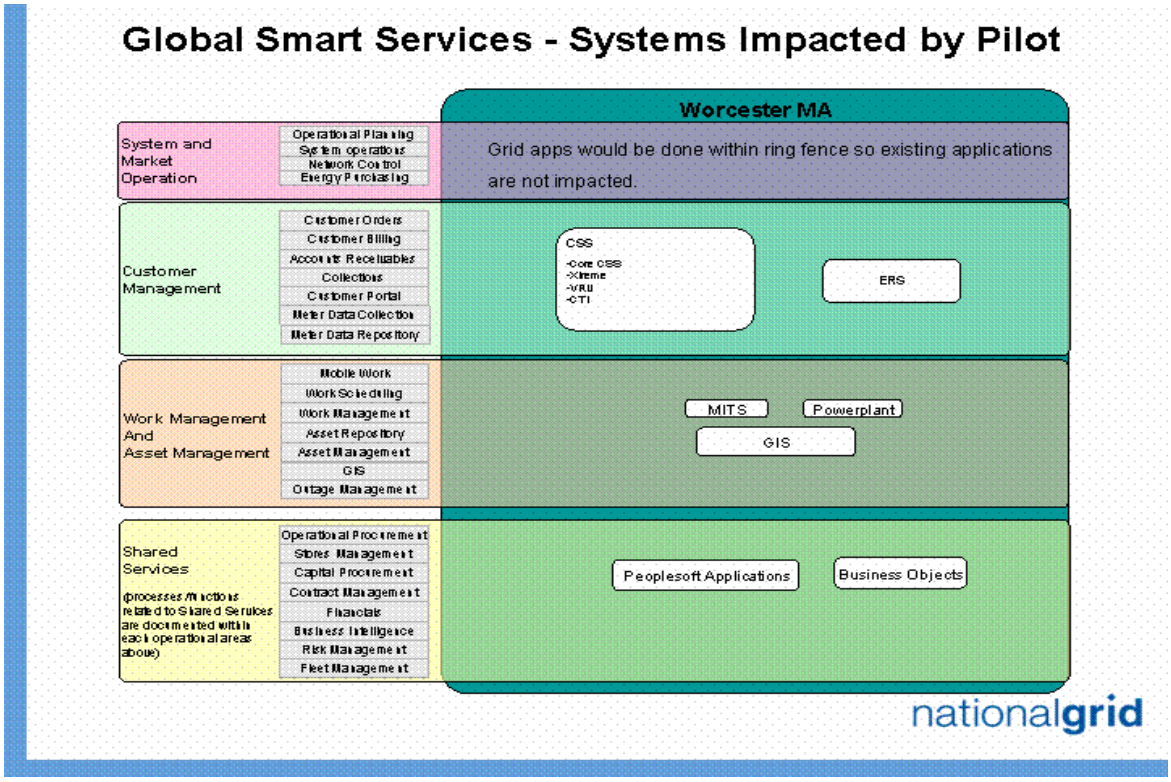
- Analysis of the IS Service Catalogue to remove:
  - Applications with a current status of 'Decommissioned'
  - Applications within the Business Area of 'Transmission' (The Smart Program will only focus on Distribution and Metering)
  - Applications relating to 'Gas Processes' as the Smart Program will only focus on Electricity Processes
- Review of the National Grid Transformation Route Map. This provided a high level view of the key applications expected to be in use within the National Grid IS Landscape, both within 2008 and beyond to 2011 and 2013.
- Collaboration with key contacts from National Grid Business and IS (referenced in Appendix), to validate the current information available for each application.
- Referencing of the Business Requirements identified for the Program
- The list was further narrowed with the selection of Syracuse and Albany Capital District as the Program sites for the New York regulatory region

3.3 Identifying the Gap

The Business Architecture document details the key Business Processes to be implemented in the Smart Program. The impact on the current Legacy Applications was identified by aligning applications with the Smart Business Processes. (The alignment with the specific Smart Business Processes is detailed in Section 5)

Collaboration with NG Contacts verified the gap and quantified the Level of Effort (LOE) required to modify the applications to support the Smart Business Processes.
(Note – the full list of NG Contacts leveraged for input is included within the Appendix of the document)

The presentation below displays the current Legacy Systems within the National Grid IS landscape considered to be impacted by the Smart Services Program roll out. The specific impacts to these applications are detailed in subsequent sections of the document.

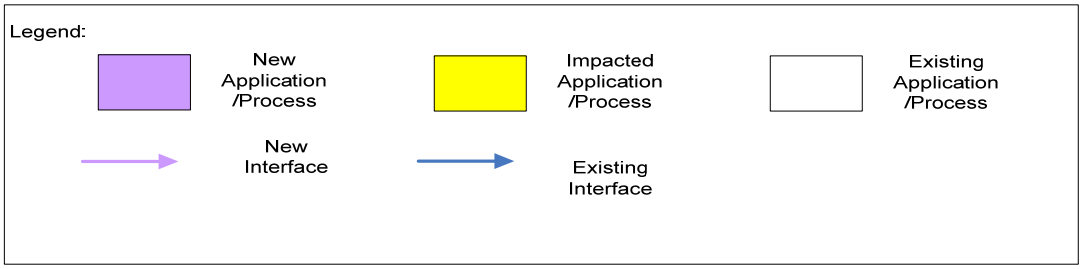

Global Smart Services - Systems Impacted by Pilot
Worcester MA
System and Market Operation
Operational Planning
System operations
Network Control
Energy Purchasing
Grid apps would be done within ring fence so existing applications are not impacted.
Customer Management
Customer Orders
Customer Billing
Accounts Receivables
Collections
Customer Portal
Meter Data Collection
Meter Data Repository
CSS
-Core CSS
-Xtreme
-VRU
-CTI
ERS
Work Management And Asset Management
Mobile Work
Work Scheduling
Work Management
Asset Repository
Asset Management
GIS
Outage Management
MITS
Powerplant
GIS
Shared Services
(processes/functions related to Shared Services are documented within each operational areas above)
Operational Procurement
Stores Management
Capital Procurement
Contract Management
Financials
Business Intelligence
Risk Management
Fleet Management
Peoplesoft Applications
Business Objects
nationalgrid

4. Gap Details

The following section details the specific gaps that exist in enabling existing legacy applications to support the Smart Program.

The diagrams within this section depict at a high level the systems impacted by the Gap Analysis. Within the diagrams, changes to be introduced at a system level are highlighted. These are identified as being:

- Changes required to current systems
- New Smart functionality



4.1 Customer Management

4.1.1 Meter Reading and Repository

The proposed solution will utilize the existing ERS (Energy Resource System) as the central repository for all Meter reads for downstream applications such as PULSE/WSA etc. The Meter Data Services organization within National Grid has an ongoing project to consolidate meter reads into the Energy Resource System.

Meter Data Management and Analytics will be completely redesigned for Smart Metering, hence a newly acquired MDMS (Meter Data Management System) would feed the interval consumption data from SMART customers to the ERS in the necessary format. This would make the ERS the single source of Meter reads for all downstream applications.
(Note - A performance test is scheduled for this system which will test its scalability in terms of additional number of meters the system can support. Utilizing the ERS for the SMART landscape would align with this initiative and minimize the impact to downstream systems and interfaces.)

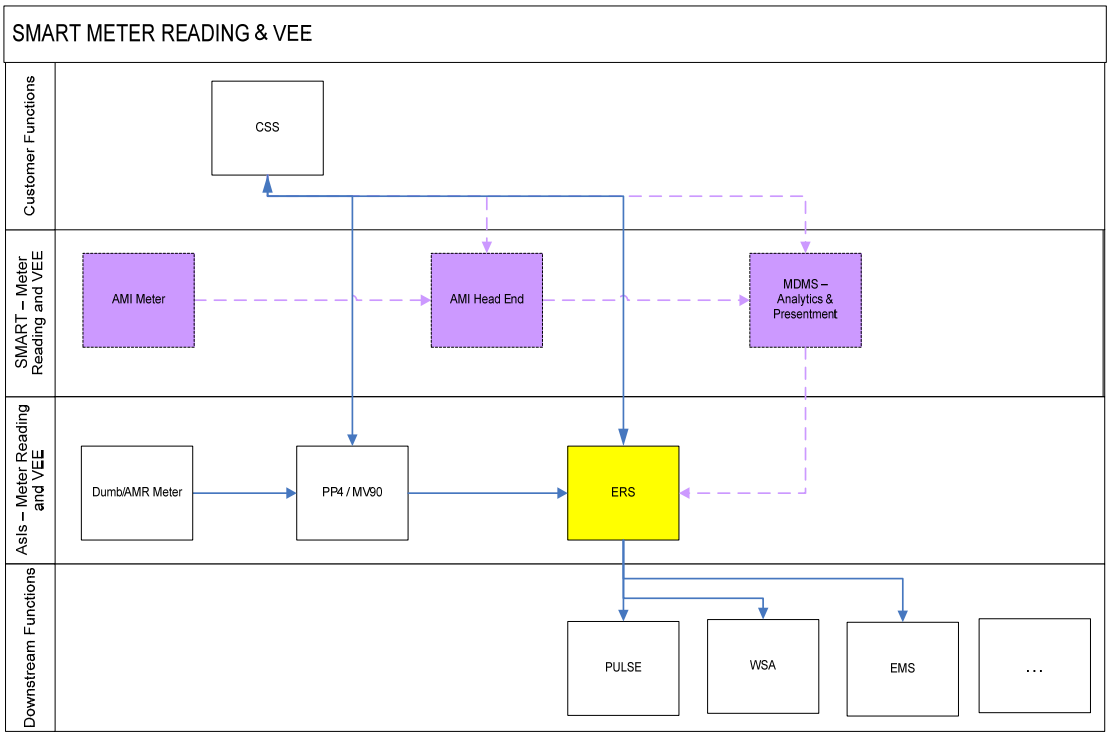
In addition to a new MDMS, the move from the AMR to AMI domain will require a new Meter Data Collection engine to be built. As with the MDMS, this will be newly acquired for the Smart Program.

Note - The MV90 system is currently used within National Grid for Meter Data Collection and Management purposes. This application is not being considered ongoing for the Smart solution,

due to scalability issues, and the difficulty involved in making large scale changes to the system. This has been confirmed by the key users of the system within National Grid IS.

The MV90 system has been depicted in a number of the process maps below, to show the As-Is scenarios, and how some 'Non-Smart' meter data will be handled in the future, however this is not included as part of the impacted systems.

The following diagram shows the high level As-Is and To-Be scenarios for the Meter Reading Services.



The specific gap details in the Meter Reading and Repository area are as follows:

Application Name	To Be State	As Is State	Gap	Impact	Effort
ERS	ERS should be able to provide consumption data for SMART Electric meters to downstream applications	The System provides electric and gas consumption data related to Non-SMART customers to various downstream applications	The System would need some modification to identify and store the information coming from the MDMS as being related to the SMART customers	Medium	6 Weeks

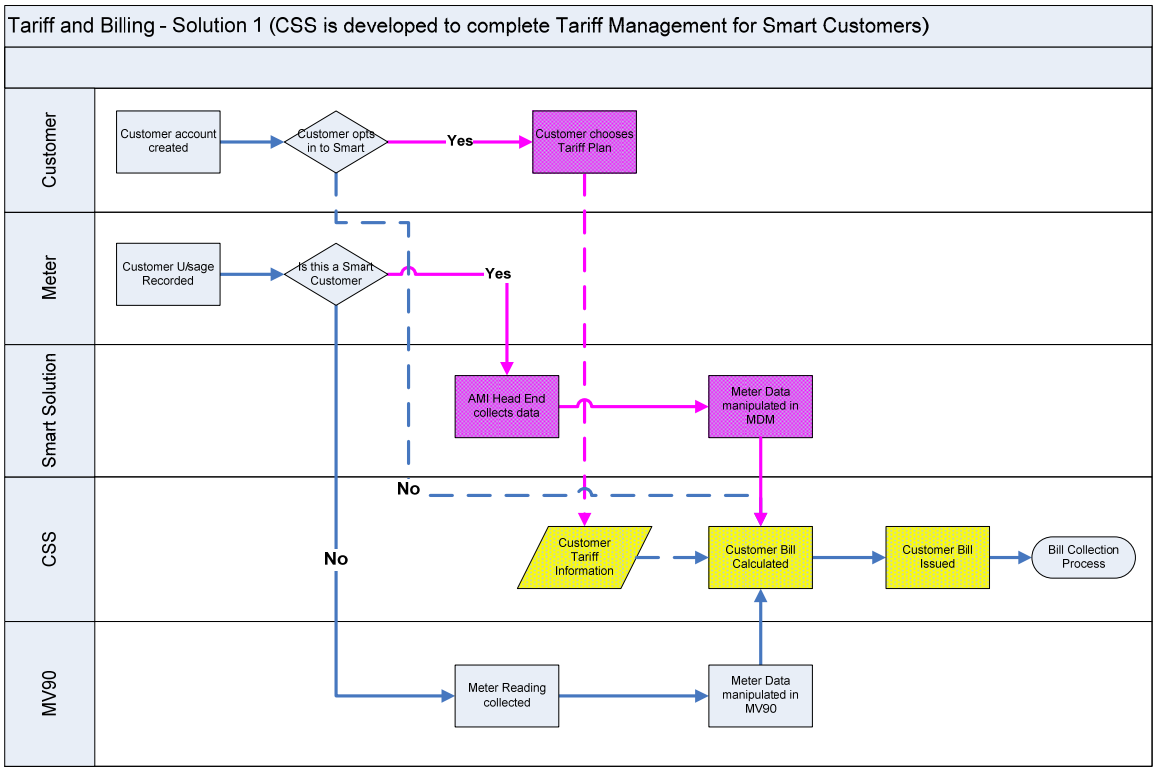
4.1.2 CSS Billing and Tariff Management

For smart services, there will be several programs required to cater to the various options available to customers such as Dynamic Pricing, Time of Use (TOU) Tariffs, etc. The National Grid Billing System will be required to support this. In addition, the CSS system will require changes to flag a customer as 'Smart', and associate the different billing programs with the Smart customers.

To support the CSS system in the Smart Program, some additional tariff management and complex billing functionality may be required outside of CSS. This will be completed within either the MDMS or a new complex engine.

The process diagram demonstrates the proposed solution:

The current CSS system will be used to perform the Tariff Management for Smart data received from the MDM. This would mean customization to CSS to include the Tariff's related to Smart customers.



The specific gap details for CSS Billing and Tariff Management are as follows:

The total estimated Level of Effort to make the changes to the Billing and Customer Handling systems is 74 person months.

Application Name	To Be State	As Is State	Gap	Impact	Effort
Core CSS	Support different programs (tariff structure)	As of today CSS has multiple tariff structures based on the Geography/Customer type / Time of Use etc and can add new ones as needed.	A new set of tariff structures has to be setup to support the SMART program	Low	1 & ½ Person Months Duration 4 Weeks
	Support dynamic tariff structures based on peak consumption period	As of today the CSS can create and maintain multiple tariff structures but does not support dynamic creation/modification of tariff structure.	New functionality is to be added in CSS to process the peak consumption data and update the associated tariff structures	High	5 Person Months Duration 10 Weeks
	Support of tariff structures relating to demand response events	There is no such tariff structure related to this	Major changes are required to support possible innovative tariff components around demand response programs like direct load control,emergency based demand response, interruptible/ curtailed rates/demand bidding etc.	High	16 person month Duration 6-8 months A base effort (1200 man hours) will be required to support this. In addition to support each tariff additional efforts required (@320 man hours)
	Support of prepayment products and gift card	There is no such functionality available at this point in CSS	Major changes are required to complete design of new functionality including interfacing with	High	17 person month Duration 6-8 months

			finance		
	Identify a customer as a SMART customer	As of today CSS can classify Customers into different categories	No Gap. Effort would be required for only configuration & testing.	Low	1 & ½ Person Months Duration 4 Weeks
	Associate SMART customers to different tariff programs	As of today Customers can be associated to different tariff structures	No Gap. Effort would be required for only configuration & testing.	Low	1 & ½ Person Months Duration 4 Weeks
	Additive /Deduct relationship	As of today CSS can identify Master-Subordinate meters	No Gap. Effort would be required for only configuration & testing.	Low	1 & ½ Person Months Duration 4 Weeks
	Data Aggregation	As of today CSS aggregates the data to calculate the bill	Data aggregation for SMART customers will have to be turned off as it will be done in the MDMS	Low	1 Person Month Duration 4 Weeks
	Work Orders for all Smart Meter related jobs should be added to CSS	Work Orders are not currently available for Smart Meters	Additional Work Order Types / Sub Types to be added to MWork for all Smart Related work	Medium	3 Person Months Duration 6 to 7 Weeks
	Cancel / Re-bill	As of today CSS can re-bill multiple periods without interval data. Re-bill of multiple periods with interval data is done manually.	CSS would have to be modified to re-bill multiple periods with interval data (but a manual work around could be implemented to eliminate this effort)	Medium	4 Person Months Duration 7 Weeks
	Data Estimation	As of today CSS estimates missing data before computing the bill	CSS will have to be modified to turn-off the estimation of missing data for SMART customers	Low	2 Person Months Duration 1 & ½ months
	Sending a flag to VRU signifying smart customers	As of today CSS can send different customer categories to VRU	CSS will have to be configured to send smart customer flag to VRU	Low	1 & ½ Person Months Duration

					4 Weeks
	Accounting	Currently hourly billing accounting is supported	Some revenue related general ledger static tables need to be changed only		3 Person Weeks Duration
	Ability to generate on demand invoices	Currently invoices are generated based on billing cycle configured in the system	On demand invoice generation will require real time communication with MDMS and out of cycle bill generation.	High	6 person month Duration: 6-8 months
	For interfacing with other systems	These interfaces are new interfaces arising out of smart project hence they don't exist	Changes will be required on CSS to consume these interfaces or produce data for the interfaces.(the interfacing effort to ESB and transformations are not considered here)		18 person months (refer following table for details)
Xtreme	Bill presented to SMART customers should be able to display additional relevant SMART information	As of today Xtreme is able to process the information related to bill presentment for regular customers from CSS	Xtreme would have to be customized to display relevant SMART information on the bills to the Customer	Medium	4 Person Months Duration 8 Weeks

The following details the effort required to change CSS to support the interfaces required to support the Smart Program:

High Level Requirement	Source System	Target System	Interface Type	Interface Frequency	Type of Impact	Level of Effort
Customer Master Information	CSS	Meter Data Management System	Asynchronous	non-real time	New	280m hours
Installs and removes of SMART equipment	CSS	MITS	Asynchronous	non-real time	Modify	200m hours

Creation of SMART Work Orders and their detail	CSS	Work Management System	Asynchronous	non-real time	Modify	180m hoursX6 (We have considered 6 such work order)
Customer Master Information	CSS	Home Automation System	Asynchronous	non-real time	New	280m hours
SMART Meter Identification Data	CSS	AMI Head End	Asynchronous	non-real time	New	280m hours
Customer Master Information	CSS	CRM	Asynchronous	non-real time	New	280m hours
Electric Interval Read Data	Meter Data Management System	CSS	Asynchronous	non-real time	New	280m hours
Electric Interval Data for Smart Customers	ERS	CSS	Asynchronous	non-real time	Modify	280m hours
Send available SMART inventory	MITS	CSS	Asynchronous	non-real time	Modify	200m hours

In addition to the CSS system some minor changes will be required to the Peoplsoft accounting systems to reflect the new tariffs created within CSS:

Application Name	To Be State	As Is State	Gap	Impact	Effort
Peoplesoft	The system must recognize the newly created Smart Tariffs to post to the General Ledger	NA – Smart Meter Tariffs not yet created	New accounting streams for Smart Tariffs will need to be created within Peoplesoft	No impact	No effort from an IS perspective required to make this change – tariff streams are continuously added in Peoplesoft so only a minor change will be required to accomplish this for Smart

4.1.3 Customer Handling

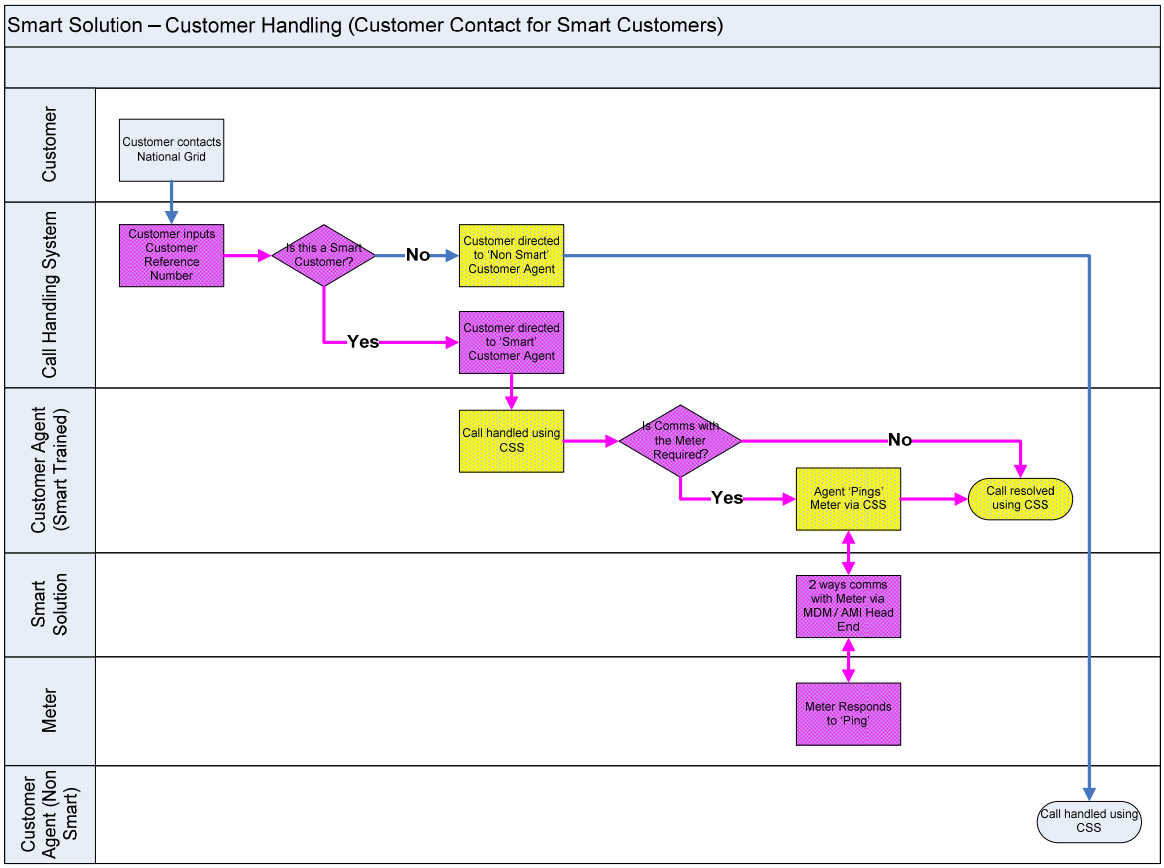
There will be several new requirements for customer support e.g. upon receipt of a complaint, the CSR may need to ping the meter. The existing CSS system will be enhanced to support the new

customer functions related to the Smart Solution by integrating with the underlying systems, such as the MDM.

The Program will be done in a ring fenced manner limited to 15,000 to 30,000 customers and will have a work force specially trained to handle the customers. These CSR's will access the customer data via the existing CSS system

The diagram shows how a customer query will be directed within CSS, to ensure the customer is dealt with by the correct agent. Upon contacting National Grid, a customer will input their customer reference number. The system will then determine whether this is a Smart customer, and will direct the customer call to the correct place. If a Smart customer, the call will be handled by an agent with the necessary training to handle the customer query.

The diagram also indicates how the agent will interact with the meter, via the MDMS.



The specific gap details for Customer Handling are as follows:

Application Name	To Be State	As Is State	Gap	Impact	Effort
VRU	This should be able to support calls from customers in the SMART program	This system currently supports calls from the regular customers	Significant customization is expected to this application to enable supporting SMART customers	Medium	3 Person Months Duration 1 Month No additional hardware would be needed assuming the same call centers would be used
CTI	Should be able to pass on unique identifier to the CSR to identify the SMART customers	The system passes on the phone number or customer account number to the CSR GUI	No Gap. Effort would be required for only configuration & testing.	Low	1 & ½ Person Months Duration 4 Weeks

4.2 Asset and Work Management

The systems used within the Work & Asset Management areas are as follows:

- MITS (Meter Asset Register)
- AIMMS (Substation Asset Register)
- GIS (Grid Asset Register)
- MWORK (Meter Mobile Work System)
- STORMS (Construction Mobile Work System)
- iScheduler (Workforce Scheduling System)

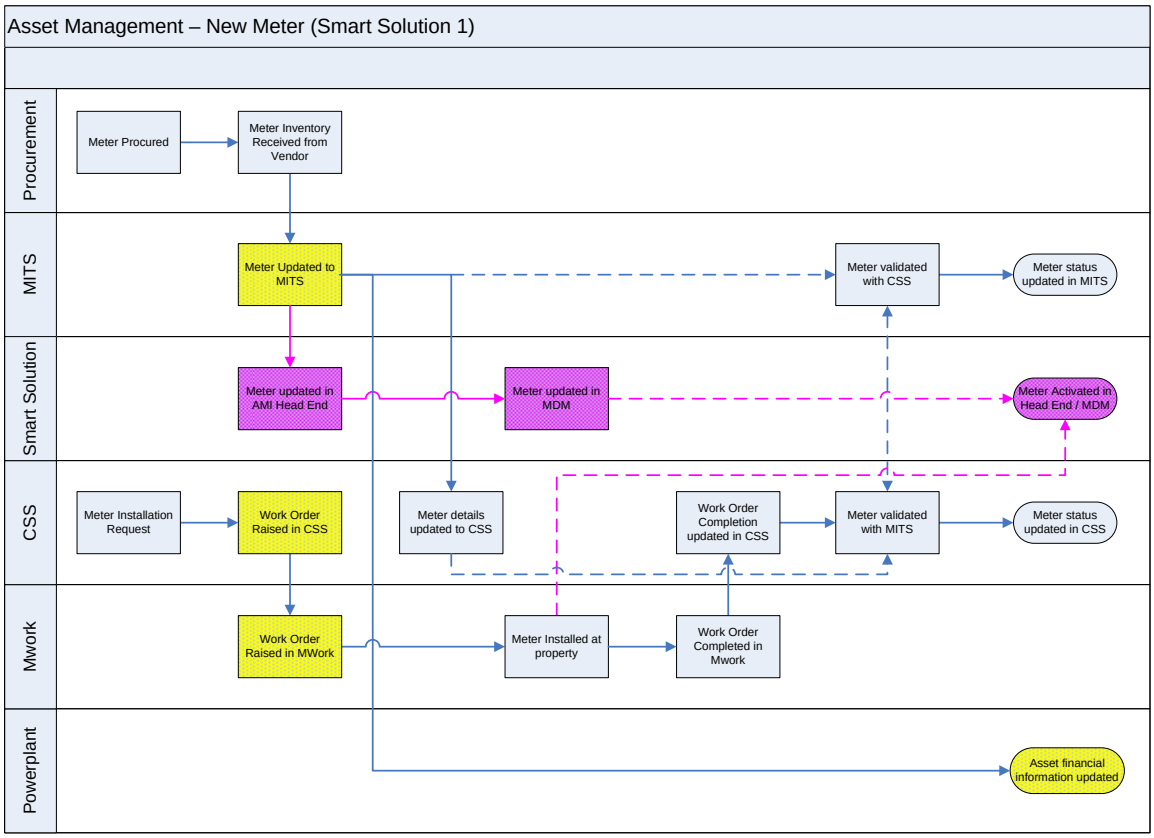
Based on the analysis completed, STORMS, iScheduler & AIMMS will remain the same. MITS and Powerplant will require changes with respect to the new Smart Meters being procured.

New Meter Installation

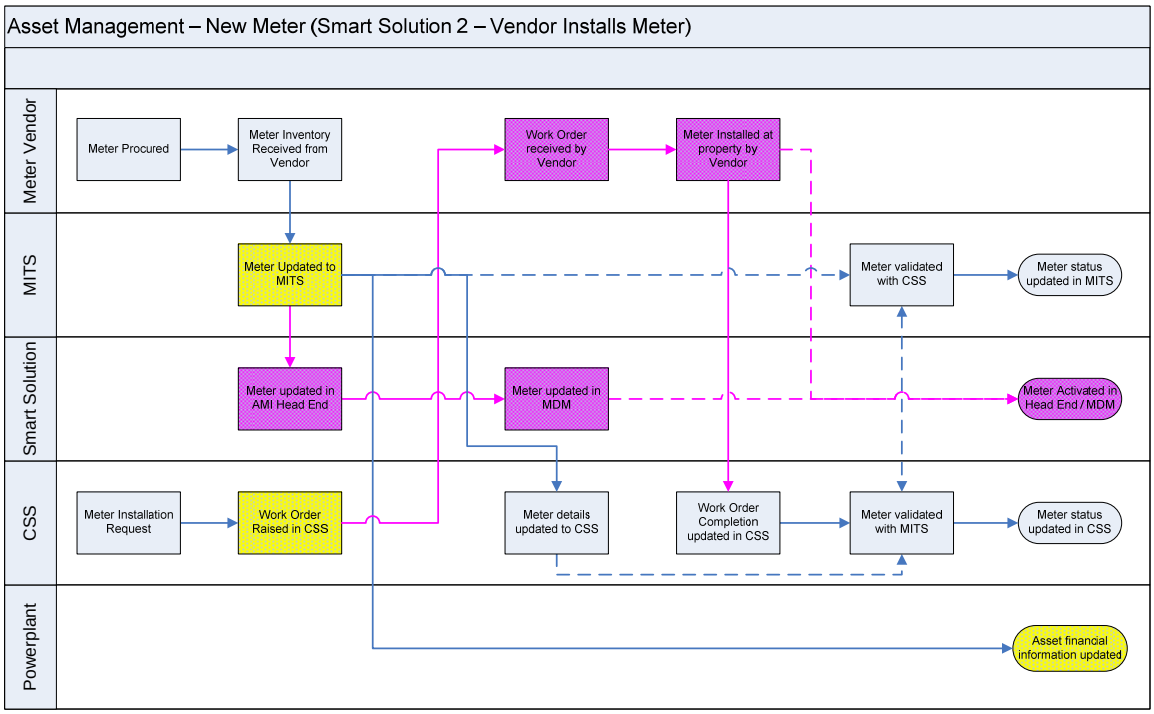
The current MITS (Meter Inventory Tracking System) system will be used for Asset Management of Smart Meters. This would require changes to MITS (see below) to facilitate this change. In addition, the MITS system will update the AMI Head End with details of new meters procured.

The meter installation process will require the support of MWork and the Meter Vendors. The process diagrams show the system impacts in of the two scenarios in terms of installing the Smart Meters.

Solution 1 assumes MWork will perform Smart Meter installations and Smart Meter related work, and would therefore (along with CSS) be required to change accordingly.


Asset Management – New Meter (Smart Solution 1)
Procurement
MITS
Smart Solution
CSS
Mwork
Powerplant
Meter Procured
Meter Inventory Received from Vendor
Meter Updated to MITS
Meter validated with CSS
Meter status updated in MITS
Meter updated in AMI Head End
Meter updated in MDM
Meter Activated in Head End / MDM
Meter Installation Request
Work Order Raised in CSS
Meter details updated to CSS
Work Order Completion updated in CSS
Meter validated with MITS
Meter status updated in CSS
Work Order Raised in MWork
Meter Installed at property
Work Order Completed in Mwork
Asset financial information updated

Solution 2 is based on the assumption the Smart Meter Vendor will install the meter, and will be responsible throughout the Program for maintenance work related to the meter. In this case, the vendor will need to provide MITS with an equivalent file (for a new meter), to enable this to be updated in the system and for the details to be issued to CSS. In addition, CSS will require an interface with the vendor Work Order solution, both to raise the Work Order and to update the details of the completed Work Order in the system.



The gaps identified therefore fall under the applications listed below:

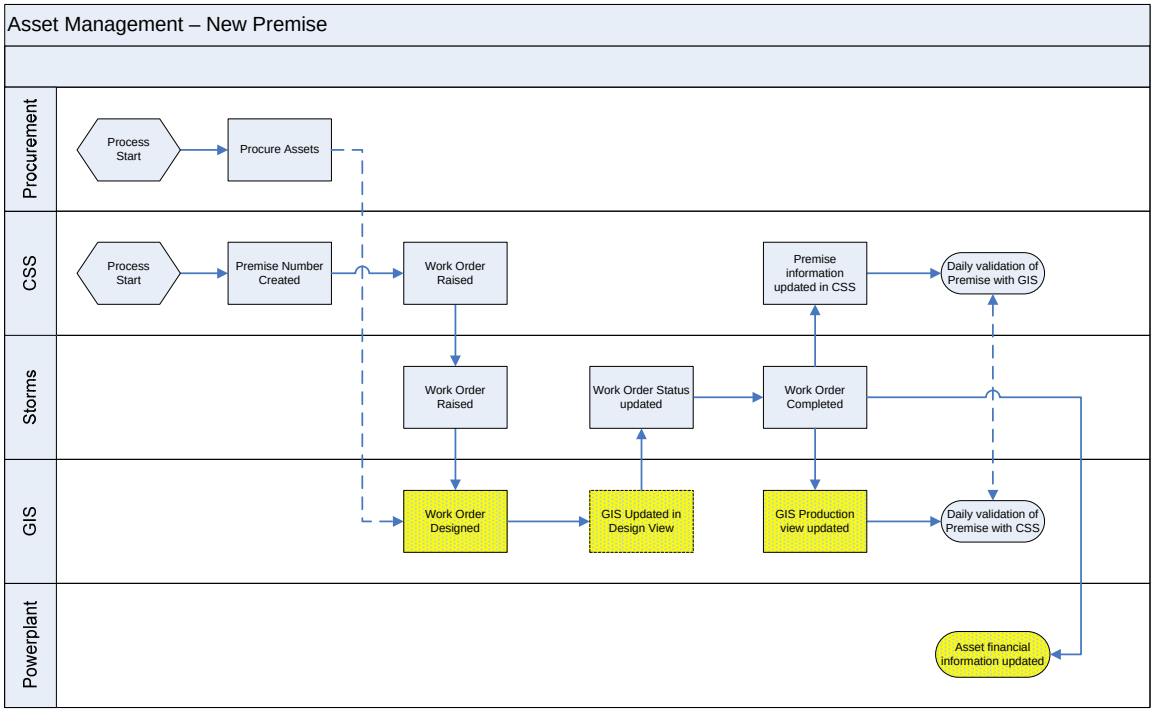
The total estimated Level of Effort to make the changes to the Asset & Work Management systems is 14 person weeks.

Application Name	To Be State	As Is State	Gap	Impact	Effort
MITS	Requires a flag to identify Smart Meters	MITS contains a flag to identify AMR Meter MITS already has the ability to add a new meter flag	Flag to be added to MITS to recognize Smart Meter	Low	1 person week Duration 1 week
	Requires additional data fields to	MITS contains data fields for attributes of	Additional data fields to be added to	Medium	2 person weeks

	recognize attributes of a Smart Meter (Comms Device)	dumb and AMR meters	MITS to recognize Smart Meter attributes		Duration 1 week
	An additional daily file should be sent to the AMI Head End, containing the details of new meters procured	No file is currently sent to Head End system – MV90 (files issued from MITS to CSS on a daily basis)	Additional daily file to be created from MITS to populate the AMI Head End with the Smart Meter details	Medium	3 person weeks Duration 3 Weeks
	Smart Meters to be flagged in weekly file to Powerplant	Meter is flagged based on whether Residential or C&I	Weekly file to Powerplant to be amended to recognize Smart Meters as a separate category	Low	1 Person Week Duration 1 week

Grid Devices

The diagram shows the process for the creation of a new premise. Due to the way Grid devices are recognized within the Asset Management system, only minor customization will be required to the GIS system, as detailed below. Assets to be procured through Smart are considered to sit 'outside the fence', hence no impacts to the AIMMS substation assets register exists.



Application Name	To Be State	As Is State	Gap	Impact	Effort
GIS	Devices within GIS need to be flagged as 'Smart' by a symbol	Provision for flagging a device as Smart has been incorporated within GIS through the Distribution Automation Program (in Syracuse-NY)	To be confirmed, potentially no gap exists if process from DA Program is followed – to be confirmed by National Grid	Low	2 Person Weeks Duration 1 Week
	Equipment No. should reflect the device is Smart	Provision for Smart specific Equipment No. has been	There is no customization need. While entering the	No impact	1 Person Week Duration

		incorporated within GIS through the Distribution Automation Program (in Syracuse-NY)	data, the planner has to enter a new letter (training issue & manual process)		1 Week

In addition to the Asset Management systems, as a result of the changes to the process, some minor changes are required within the Powerplant and Peoplsoft accounting systems:

Powerplant	The system has to accept smart meter data from MITS	Currently there no is smart meter related data in either MITS or Powerplant	The meter has to be identified in MITS as smart meter. Then Powerplant would need to be configured to consume & process this data	Medium	1 Person Month Duration 1 Month
Peoplesoft	The system has to accept the Purchase Order for the Smart Meter from the relevant vendor	Currently, Peoplesoft will not contain the specific meter or vendor being procured in the Smart Program	New meter type and vendor to be created in the system for Inventory and General Ledger purposes	No impact	No effort from an IS perspective required to make this change – minor change only to create meter and vendor in system

4.3 System and Market Operation

It has been proposed that within the Grid area the existing applications will not be utilized to support the Smart Program. The current intention is to leverage the new OMS/DMS solution, which is being rolled out within National Grid Electricity Distribution, and use this to provide Smart functionality within the Grid area.

The current Legacy Applications will be required to interface with the new solution offering. This will replicate interfaces with the current OMS and EMS systems. The details of this interface have been referenced in the document 'Interface Specification', and will be explored further as part of the Solution Design phase.

4.4 Shared Services

As part of the Smart solution, operational/tactical reporting and strategic analytics requirements will need to be addressed. It is proposed the existing SAP Business Objects suite used at National Grid be leveraged. This gap will be addressed in detail during the Business Requirements phase, once the specific business metrics and KPIs for the Program have been identified.

Changes to other systems within the Shared Services area, such as accounting systems Powerplant and Peoplesoft, have been detailed in the above sections within the specific business area in which the impact occurs.

V. SMART GRID REQUEST FOR INFORMATION

Through the RFI, National Grid sought to obtain the most current information on Smart Grid technologies, services, and pricing. This process was not designed to identify specific vendors, but was instead intended to familiarize National Grid's Pilot team with the capabilities and limitations of key technologies and to identify those technologies and services that will be utilized during the Pilot. Details of the RFI process and its outcome are provided below.

A. RFI Process

Due to the size and scope of the RFI, technical specifications were divided into three distinct areas:

- Information Systems and Telecommunications ("IS" and "Comms")
- Smart Meters, Home Display Unit ("HDU") and related equipment
- Smart Grid Technology

Within each of the above areas, the RFI defined distinct "service layers," based on logical groupings of functionality. These service layers formed the Smart Services conceptual technical model, on which the RFI content was based.

Eighty-five vendors were invited to submit relevant information for the solution as a whole, or for specific service layers. National Grid's assumption is that no single technology solution would address all of the diverse customers and circumstances of the Pilot, and therefore invited proposals that encompassed a multitude of technology options.

The RFI requested detailed information about products, software and services; functionality, availability, pilot and mass deployment pricing; customer references and vendor financial information (to assess viability as well as readiness to undertake the Pilot program and inform volume production rollout).

MAJOR EVENT TIMELINE

ACTIVITY	**DATE**
RFI Issued	December 12th 2008
Vendors Pre-Bid Meeting	December 16th 2008
Last date for posting queries on Q&A	January 5th 2009
RFI Closing Date & Time	January 13th 2009

The RFI imposed the following minimum requirements as a guide for responses:

- Integrated grid / network communications.
- Advanced smart meters that support real time interval measurement, communication of consumption details, upgrade ability and control from a remote system.
- Load management capabilities to support demand side management programs.
- Remote status detection and operation of electric distribution grid equipment.
- Time of use (TOU) hourly pricing.
- Coverage of a minimum 0.25% of National Grid's Massachusetts service territory.
- Reductions of 5% in peak and average load consumption by Pilot participants.
- Vendors were required to include full technical details and compliance with specified functionality within each service layer with their responses. In addition to requests for individual component solutions, we also invited more comprehensive proposals that included multiple components or full solutions.

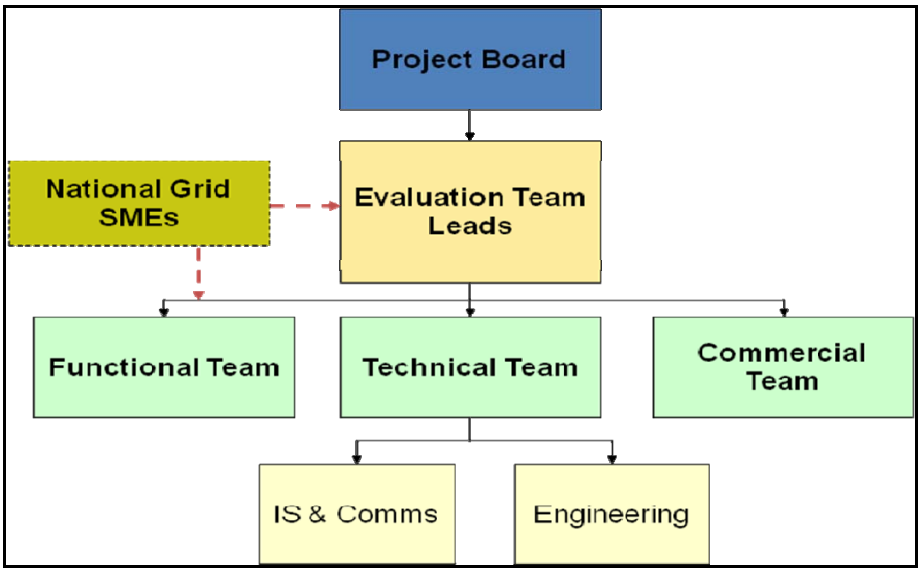
B. Evaluation Process

The RFI evaluation process was designed to consider National Grid's business, technical, financial, and regulatory needs and objectives for the pilot. The Evaluation Team was led by a dedicated Smart Project Team and via a series of workshops, engaged National Grid subject matter experts in customer service, communications, metering, grid operations, and rates. In addition, outside experts with experience in Smart Grid technology, utility information systems, pilot and mass deployments, business, and finance participated.

Because the RFI was released to a wide list of vendors, the evaluation process was designed to funnel from a large list down to the best potential options in three stages:

- First level evaluation: Vendor Self Assessment scoring.
- Second level evaluation: National Grid Project team scoring verification and assessment workshops.
- Third level evaluation: Detailed Vendor clarification workshops.

Evaluation was carried out in a structured way with dedicated teams focusing on key aspects, as presented below:



The table below describes the high level activities and responsibilities of the evaluation teams. This matrix indicates whether a team was Responsible, Accountable, Consulted or Informed ("RACI") regarding each specified activity.

Activity	Role	R	A	C	I
Commercial Evaluation	*Procurement Team*	√	√		
	Others - Evaluation Team	√		√	√
Evaluation of Grid End Point Devices Responses	*Business Project Manager*		√		
	Business Team	√			
	Grid SME	√		√	
	Others - Evaluation Team				√
Evaluation of Customer Facing End Point Devices Responses	*Business Team Lead*		√		
	National Grid SME	√		√	
	Business Team	√			
	Others - Evaluation Team				√
Evaluation of IS and Comms Responses	*IS Project Manager*		√		
	IS Team Lead		√		
	National Grid COMMS SME	√	√		

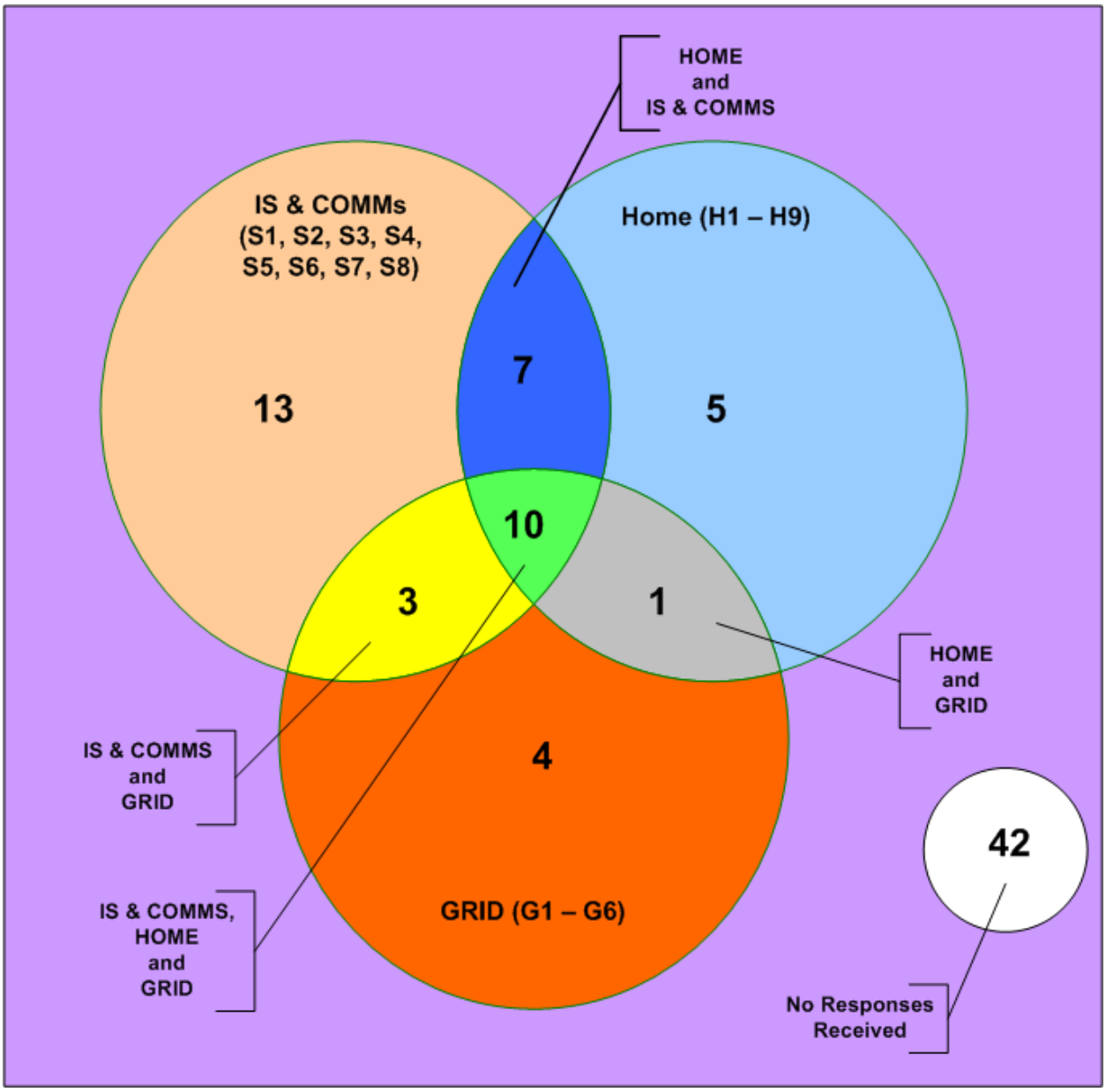
Activity	Role	R	A	C	I
	IS Team	√			
	Others - Evaluation Team			√	√
Recommended Solution Options	*Steering Group*		√		
	Procurement Team	√			
	Business Team	√			
	IS Team	√			
	Others - Evaluation Team			√	√

C. Responses

As noted, 85 vendors received the RFI, and National Grid received forty three responses. The responses were grouped as follows, based on National Grid's internal designation of Service Layer Groups:

i. Responses by Category

Category	Total Responses Received
Home (H1 – H9)	5
Grid (G1- G6)	4
IS and Communications (S1, S2, S3, S4, S5, S6, S7, S8)	13
Home and Grid (H, G)	1
Home and IS & Comms (H and S layers)	7
Grid and IS & Comms (G and S layers)	3
All (H, G and S layers)	10
No Responses Received	42
Total	**85**



ii. First Level Evaluation – Vendor Self Assessment

The vendor RFI responses were rated using predefined, simple evaluation criteria that relied on a consistent scoring mechanism. Vendors were provided with specific requirements and expected to respond using a Microsoft Excel format template predefined in the RFI. Vendors were asked to score their products and services based on Compliance with the specified functions in each of the service layers and current availability.

Functional maturity was scored:

2 …if Vendor considered the specific function was fully met
1 … if Vendor considered the specific function was partially met
0 … if Vendor considered the specific function was not met

Availability was scored:

5…if vendor considered the function to be production available
4…if vendor considered the function to be in beta testing
3…if vendor considered the function to be in proof of concept testing
2…if vendor considered the function to be in development
1…if vendor considered the function to be planned for a future release
0…if vendor considered the function to be not available

A combined factor score (functional maturity times availability) was applied to each function and then averaged across all functions in a particular service layer.

Vendor offerings were then allocated to one of three categories based on their overall combined factor score:

7 and above……..HIGH
3 to 7…….MED
0 to 3 ……LOW

HIGH	**Available Solution**
Criteria	Responses that fall into this category indicate that a vendor product / solution: • Has proven technology. • Has hardware and software production available. • Is ready for deployment (and may already be deployed at other sites). • Supports requirements from RFI. • Has strong organizational support e.g., warranty, service support.
Considerations	Responses from vendors with solutions falling under this category will be

	considered for detailed analysis and further vendor workshops
MEDIUM	**Emergent**
Criteria	Responses that fall under this category indicate that a vendor product / solution: • Has established customer demo units. • Is not yet deployed into production.
Considerations	Such responses will be considered to fill-in any service layer gaps left by the above (HIGH category solutions) in the Pilot framework. Vendors for who the responses fall under this category may be engaged by National Grid at a later stage for further evaluation.
LOW	**Conceptual**
Criteria	Responses that fall under this category indicate that the vendor product / solution is in a conceptual stage and not yet built or deployed into production.
Considerations	Vendors for whom the responses fall under this category will be not be considered for the Pilot. However, such vendors will be referred to National Grid R&D and will be monitored. If they become available and are deemed satisfactory during the course of the Pilot, they could be considered for inclusion for volume roll-outs

*Those products and services ranked in the LOW category were not included in the second phase of the evaluation process, team evaluation.

iii. Second Level Evaluation – Project Team Assessment

The team evaluations were designed for National Grid to validate the vendors' self assessment score by reviewing responses against the supporting information provided by the vendors and based on information obtained from their references. The team evaluations were organized into functional and technical workshops, as follows:

Functional/ Technical Workshops (Service Layer Reference)

- Workshop 1: Grid Facing End Point Devices (G1 – G6)
- Workshop 2: Metering Devices (H1-H4)
- Workshop 3: Customer Facing End Point Devices (H5-H9)
- Workshop 4: Communications (S1)
- Workshop 5: Meter Data Management (S2)

- Workshop 6: Grid Data Management (S3)
- Workshop 7: Integration - Application and System (S4, S8)
- Workshop 8: Web Presentation, Messaging and Mobile Devices (S5-S7)

More than thirty National Grid subject matter experts attended the functional and technical workshops. All of the "medium" and "high" scored solutions from the First Level Evaluation stage were re-evaluated by these teams, using the supporting documentation provided by each vendor. The workshop teams reviewed the vendor self assessment scores and adjusted them based on consensus agreement of:

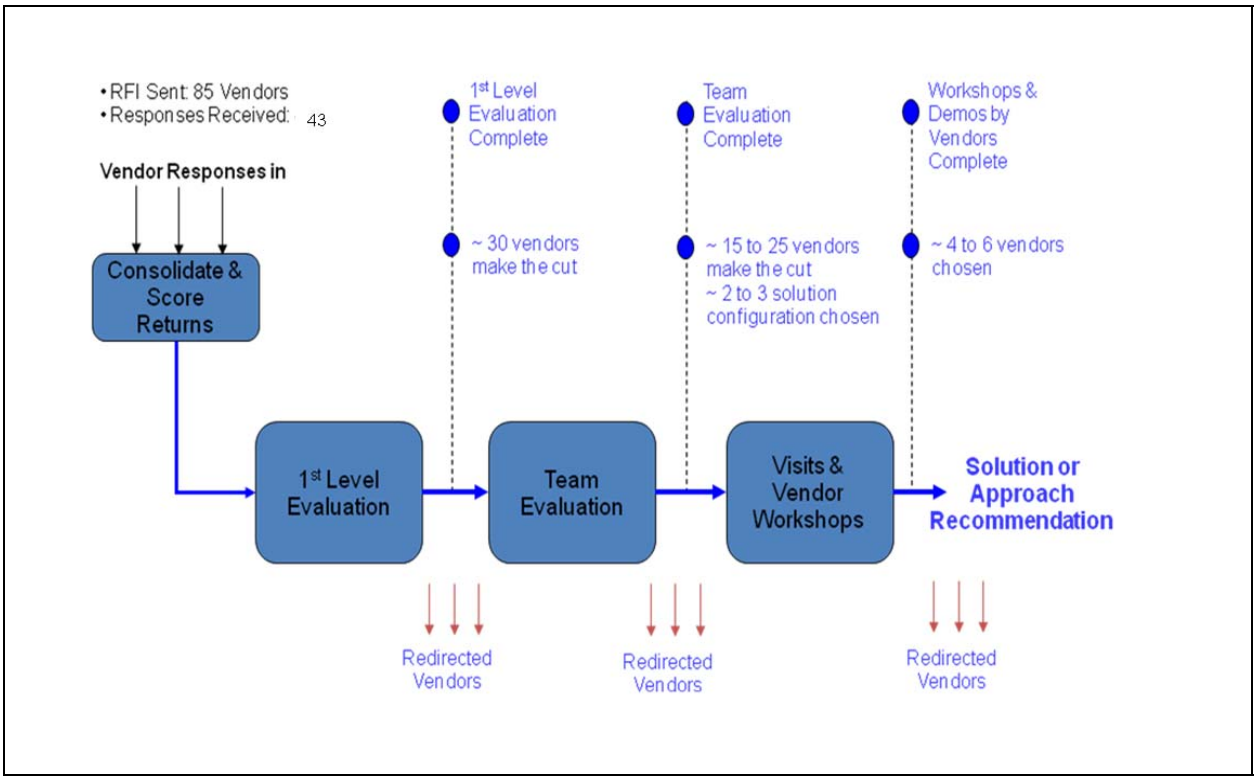
1. Product/ Solution maturity
2. Product/ Solution scalability
3. Product/ Solution architecture flexibility
4. Product/ Solution interoperability
5. Proven track record

iv. Third Level Evaluation – Vendor Clarification Workshops

Those vendors scoring highest in the first two phases by service layer were advanced to a third phase for further consideration. These vendors were engaged in direct, detailed discussion with the National Grid Smart Grid project team and relevant subject matter experts in a workshop environment. The objective of these workshops was to expand National Grid's understanding of the technology, services, and vendors beyond the level of information that can be captured in documentation or RFI responses. This interactive phase enabled the team members to articulate National Grid's Smart Grid vision, ask specific questions and generally refine their understanding; and gave vendors the opportunity to explain their responses, ask their own questions and present additional information regarding their offerings. These discussions focused on three major areas, technical solution, pilot implementation, and commercial issues (pricing and financials), but also included areas such as security considerations, product and company scalability, and clarifying functional capabilities.

D. **Evaluation Results**

As show in the graph below, the process started with 43 vendors. Working through each step in the evaluation process resulted in fewer eligible vendors until the last step which provided the Company with a group of 4-6 vendors.



E. Summary

National Grid has conducted a robust and inclusive procurement process to identify and cost viable technology solutions. National Grid has identified multiple providers in each Service Layer and is ready to begin negotiations, once we receive regulatory approval.

Attachment 10

SMART GRID COMMUNICATIONS

Smart Communications Technologies

In the development of our Smart Grid Program, we separated the required communications into three layers. The technology chosen for each layer along with key selection drivers are detailed in the following paragraphs.

Home Area Network (HAN)

As part of the Smart project, National Grid will deploy a Home Area Network in customer homes. This network will provide connectivity from the electric meter to a number of devices. These devices will include, but are not limited to:

- Load Control
- Thermostats
- Other utility meters
- In-home display for displaying pricing and usage information

- Appliances
- Hot Water Heater
- Home Automation Devices

The Smart system will use the electric meter as a communications gateway into the customer home. In this configuration, the meter is expected to have the functionality and proven capability to routinely and successfully communicate externally with some devices in the home. The communications module embedded in the meter will be robust enough to support the level of communications and controls necessary for our Program tariffs.

For the Program, National Grid proposes to use Zibgee communications into the home. The vendors selected for the Program all adhere to this communications standard. In fact, nearly all bidders that responded to the RFI use Zigbee or are in the process of adding that capability, suggesting a significant level of industry acceptance. Zigbee will

provide communications between the meter and at least two home area devices. This approach will allow remote control for demand-response and will provide sufficient bandwidth for an in-home display unit. As part of the Program, we will also evaluate a more feature-rich in home solution approach that will provide automated customer control of a much broader group of in-home devices, near real-time display of consumption data and billing data, and remote access and control. This solution will require a much higher bandwidth and speed than needed for the core services. We propose deploying this capability to customers with existing broadband connections who select the most sophisticated home automation alternatives.

Local Area Network (LAN)

National Grid will deploy a series of data collectors and a LAN throughout the Program area to relay data and communications to and from in-home devices, meters, and some grid devices. The LAN topology will be point to multipoint, mesh, or a combination of both.

Local area networks will concentrate into a larger Wide Area Network (WAN). This network will provide connectivity from the meter data collectors to higher level concentrators and/or directly back to National Grid's facilities. National Grid's use of its existing fiber and a common infrastructure for grid and metering devices has been a key consideration in our technology selection. Use of the same infrastructure to communicate with grid operational devices, meters, and in-home display units will achieve cost efficiencies. The technologies under consideration for the devices on the WAN included:

- Fiber Optic Communications
- Private or Public Data Radio Systems
- Broadband Over Power-line Carrier (BPL)
- Public Cellular Networks
- Other Public Data Networks

In areas where existing National Grid network assets are available, they will be used. For example, in locations where we have a fiber multiplexor connected to one of our fiber rings, we would provision capacity from that multiplexor to the head-end location. In some instances, the LAN collector infrastructure will extend out to the locations where our multiplexors are installed. In other areas, we may need to extend the reach of the last collector. In those instances, the technology we propose to use is a private wireless WiMAX solution. A WiMAX infrastructure can be implemented to provide backhaul connectivity for multiple collectors back to one of our network points. The desire is to place WiMAX base stations at National Grid locations such as substations or service centers. In some instances we may use existing radio/microwave sites that have tower structures and space. As a last resort, we may need to lease space on an existing public communications tower or other third party structure.

Certain low-latency grid devices will communicate with the WiMAX base stations directly.

At least one of the WiMAX base stations will be collocated with National Grid network equipment. At this location, data will pass to the National Grid network with a final destination of Westboro. We believe we have sufficent network capacity in the Syracuse and Capital District areas to support the Program. This will be verified during detailed design. The interface point into the National Grid data network will be existing service center facilities or substations. We have sufficent capacity on our microwave links and/or fiber infrastructure to these facilties to support our data estimate for all Program devices.

Attachment 11

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1 Purpose

The purpose of this document is to summarize the end-to-end technological solution landscape for the Smart Services pilot program. Vendors were identified from the vendor evaluation sessions that were conducted based on the RFI responses from each vendor supporting specific service layers within the Conceptual Technical Model (CTM).

2 Information Systems Summary

Based on the vendor evaluation sessions held with participation from National Grid subject-matter experts, a number of vendors were short-listed for the Smart Solution for each service layer.

2.1 New Vendor Solutions

Service Layer	Solution Offering	Technology
S1 – HAN / LAN / WAN	Communications	• RF
S2 – Meter Data Management Services	AMI Meter Head end	• Head end software • Back office integration software
	Meter Data Management	• Meter Data Management
Customer Billing	Customer Billing	• Billing software
S3 – Grid Data Management Services	• GRID Head end • DMS & Grid Analytics	• SCADA software and repository
	• Grid Analytics	• Analytics software
S4 – Enterprise Integration and BPM	Middleware	• EAI and BPM tool
S5 – Web solution S6 – Messaging S7 – Mobile Devices	• Home Automation Head end • Web Presentation • Messaging & Mobile Services	• Customer-facing energy conservation tool
Data Warehouse & Business Intelligence	Business KPIs and Metrics	• Data Warehouse • Reporting and Metrics tools

Process Modeling	Process modeling	• Process modeling software

2.2 Existing Applications

Service Layer	Solution Offering	Vendor
CRM / Customer Services	CSS Suite	• Customer support suite
Back office applications	• Geo-spatial data (GIS) • Work Management • Work scheduling and dispatch • Asset Management	• Geo-spatial software and repository • Work scheduling and customer-system interfacing • Workforce management and field job scheduling • Asset Management and repository
Financials	• ERP (Accounts Payable / Accounts receivable) • Asset accounting	• ERP finance software solution • Asset accounting software

3 Conceptual Technical Model Service Layers

3.1 Communications (HAN/LAN/WAN) (S1)

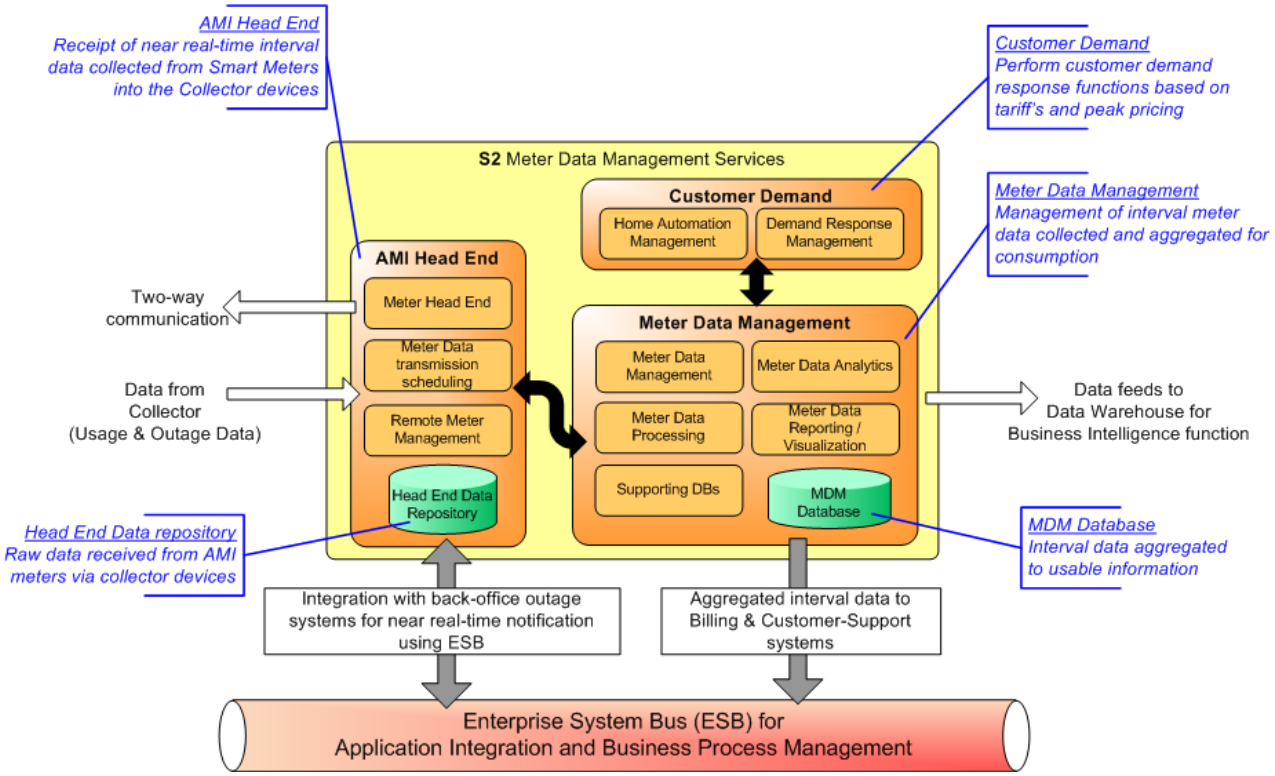
The RF LAN is a "**Hang and Run**" communication network that is self-configuring (automatic addition or removal of devices), self-optimizing, and self-healing, providing diagnostics capable of detecting abnormal device operating parameters including, but not limited to, memory failure, power supply degradation, microprocessors(s) failures (ex. watch dog events), firmware/software problems, excessive device temperature, non-responsiveness, etc.

3.2 Meter Data Management Services (S2)

The Meter Data Management System (MDMS) will serve as the system of record for all metered data and will play a central and crucial role in creating and capturing the key benefits from the AMI. Data gathered, processed and made available in the MDMS will provide near real-time intelligence in National Grid's utility operations.

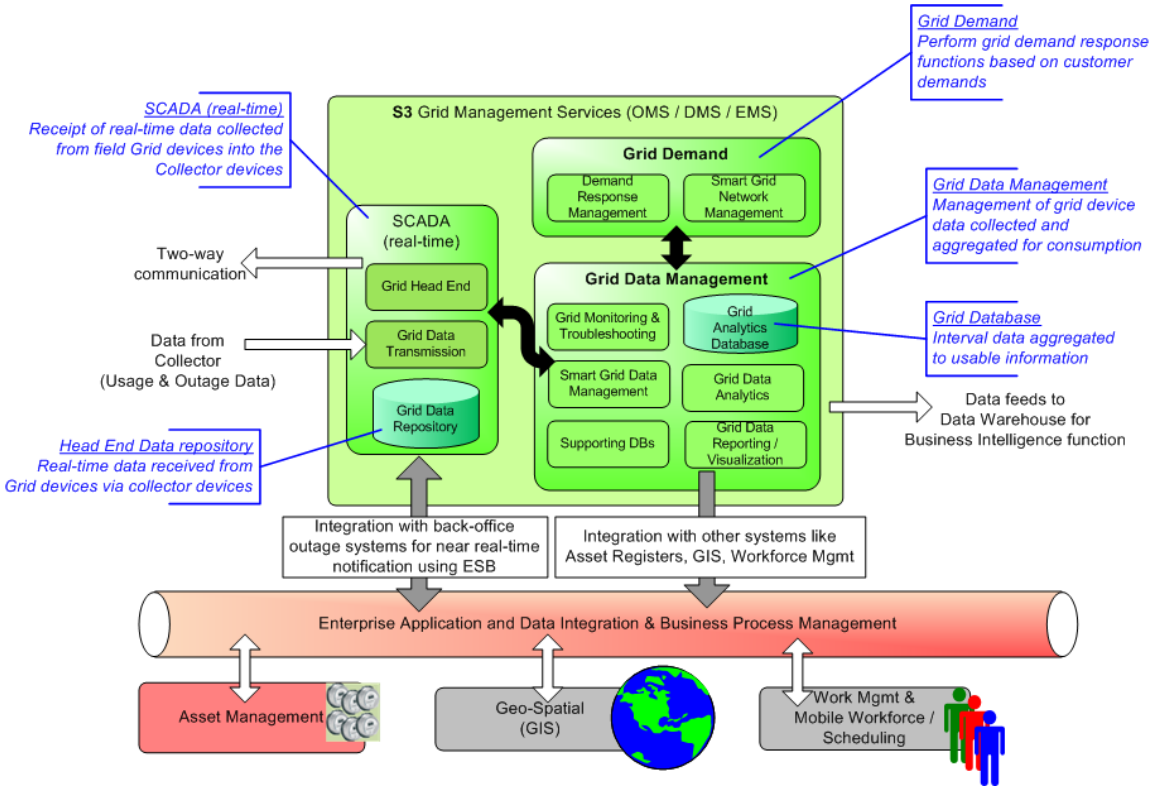
The MDMS Layer will facilitate better customer care and energy utilization by disseminating interval-based meter data to multiple applications like Customer Information Systems (CIS), Billing, Customer Care and other Distribution Network Management systems. It will bridge the Smart Services with other internal systems hence insulating internal processes from the highly evolving AMI technologies. The MDMS is broken down in service layers as below:

AMI Head End - The AMI Head End will receive Smart Meter data from the head end collectors and perform two-way communication (using different protocols) between the MDM and the installed meters.
Customer Demand - The Customer Demand service layer within the MDMS supports management of customer meters directed from MDMS. Various peak pricing and demand functions are managed through functionality defined in this layer
Meter Data Management - The meter data management layer supports all functions related to the managing data collected and fed from the AMI head end software like aggregation of raw meter data, performing VEE (validating, editing, and estimating) functions and other functionalities related to storing of data and visualization of meter information for metrics purposes.



3.3 Grid Data Management Services (S3)

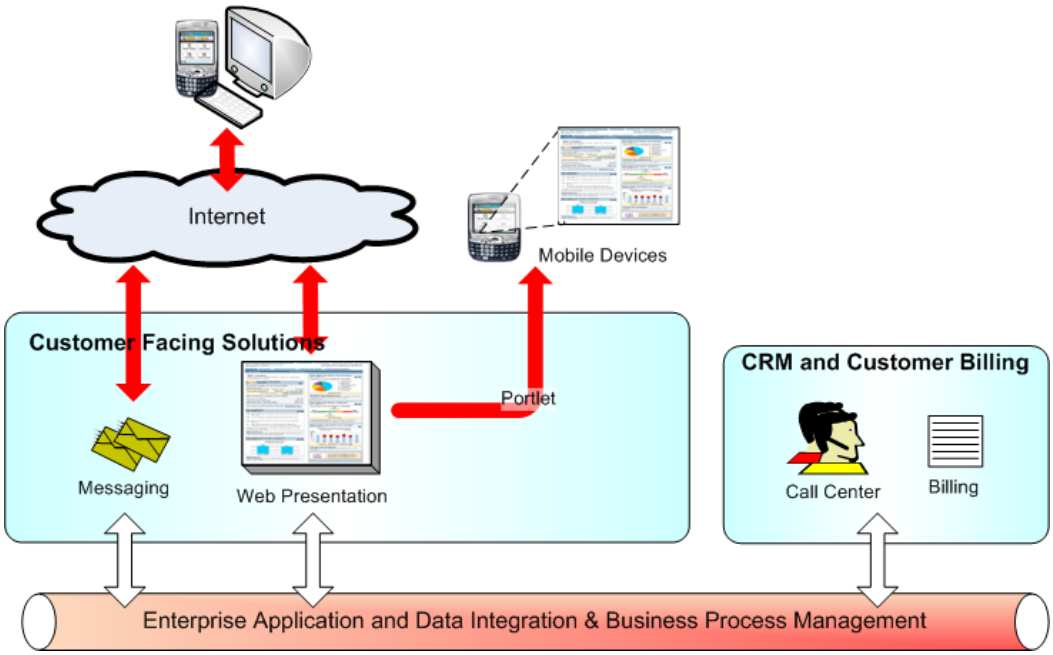
This service layer covers the functionality required for grid data transmission, processing and reporting. The layer will serve as the system of record for all grid device data received from field devices. Data is captured from the Head End software, processed and made available to National Grid's utility operations in near real-time.
National Grid's solution will facilitate better grid control and monitoring capabilities as more near real-time information is made available. To meet this requirement, the solution will be highly scalable and flexible so changes to business processes can easily and quickly be incorporated into the technical solution.



3.4 Enterprise application integration and Business Process Management (S4)

The EAI layer provides a standards-based, open, extensible platform for developing software infrastructures using a service-oriented architecture approach. This unified and comprehensive suite can help your enterprise create composite applications from existing investments as well as deliver new business services in a flexible SOA environment with no vendor lock-in.

3.5 Web Solution, Messaging and Mobile Devices (S5, S6, S7)



This includes the Customer care self service portal for all the customer requirements from bill presentment and payment to home/business management and control.

Customer Focused: Features of the customer conservation software solution include:

- Allows home owners to access and control their home energy consumption anywhere, anytime – over the Internet, from PCs, or even handheld devices such as Blackberry and iPhone. It provides full analysis of their energy consumption, billing information and time of use patterns. This analysis seamlessly ties into utility

distributed generation programs as well as user defined programs and device control to allow the home owner to have effective real-time control over how and when they use energy.
- Allows Utility Companies to execute demand control programs and receive real time feedback and reports from participating homes and communities for energy planning and grid control.
- The software is an enterprise architected, fully flexible solution. Customers can deploy the full solution, or choose to deploy those pieces that best fit their existing systems.

Grid Focused: The energy management software is an advanced smart grid and energy management solution. It provides full support for end to end grid management including support for meter, and transformer monitoring, distributed generation control and demand response execution. Through a combination of user defined programs, the software responds to grid signals, schedules, pricing or environmental signals, or on demand execution. These executions will interact with all distributed energy resources (DER), either distributed generation (DG) or demand response (DR) to enable smart power management across the grid.

3.6 Data Warehouse & Business Intelligence

The Data Warehouse will support National Grid's information needs by integrating data requirements of the enterprise and hence support the analysis and reporting requirements of the entire organization.
- The Data Warehouse serves a broad user community providing an integrated view of the organization.
- Data is cleansed and at granular level and is stored in a consistent form (not updated).
- The Data Warehouse contains time-based historical data.
- Significant or often-used data is summarized by structuring it to align with business areas. These summaries are driven by analytic requirements from the business areas.

Business Intelligence activities involve providing historical, current and predictive views of the various business operations. This is accomplished through various tools that provide multi-dimensional analysis capabilities, which will slice-and-dice through data providing insight into various business and/or customer trends to support better business decision-making. The source of data for these BI activities will be the Data Warehouse.

3.7 Process Modeling

Process modeling helps conceptualize business processes to achieve process governance and aligning enterprise IT architecture to business architecture to meet business needs. The benefits of using a process modeling tool helps in documenting and publishing process knowledge of the organization increasing process performance.

3.8 Existing Applications

3.8.1 CRM / Customer Services

Customer Services systems allows customer representatives to support Smart customers. The customer systems provide information regarding every aspect of utility customer information-service connection, meter reads, rating, billing, and more-while also undertaking associated functions like payment processing, collections, field service, and meter management.

3.8.2 Geo-Spatial Data (GIS)

The GIS system provides the X and Y co-ordinates for the location of each of the devices to assist in providing the exact location for field crew. The GIS system provides a pictorial representation of the existing topology of all the devices currently on the field.

The current system supporting the geographical positioning of the existing devices will continue to support the topological requirements of the Smart devices.

3.8.3 Work Management

Customer and Grid devices installation, repair, and maintenance activities are managed through the work management system providing the work crew with timely information.

Customer requests for maintenance activities are entered in the customer support systems generating service orders. Work status on service orders is updated by the field crew which provides the customer representatives details on status within the customer support applications.

3.8.4 Work Scheduling & Dispatch

Work Scheduling and Dispatch ensures service availability and automates field operations via dispatch, scheduling, and routing.

3.8.5 ERP (Acc Payables / Acc Receivable) and Asset Accounting

All financial functions for accounts payables and accounts receivables will be continued using the existing ERP application suite.

Asset accounting will be managed using the existing software suite with changes to handle Smart project specific devices.

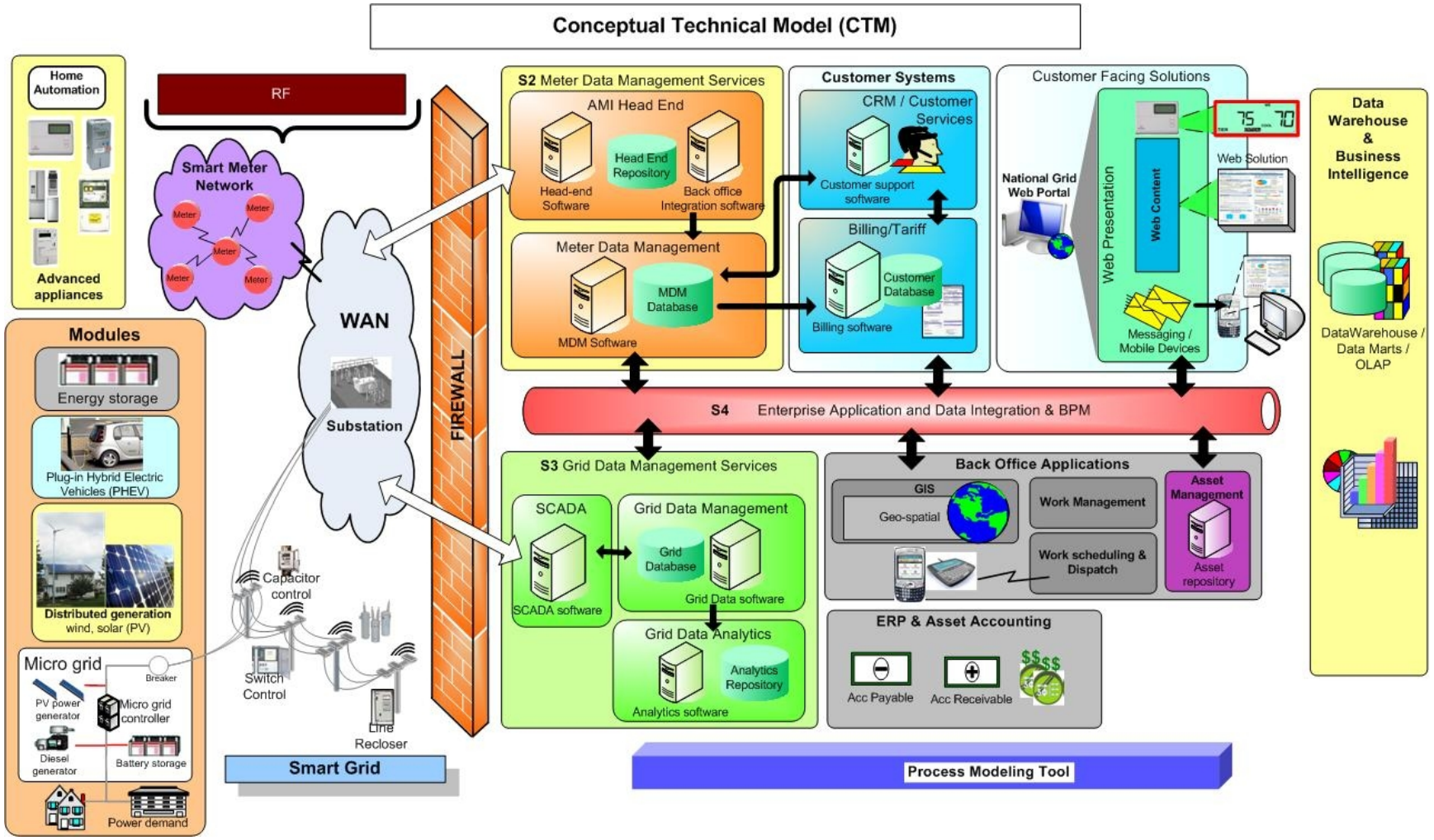
3.8.6 Asset Management

National Grid's current asset repository will be used to support the asset management functions of the Smart project. The asset repository provides details on all the metering assets currently available. It is the source for the CSS system to assign an asset to a customer.

4 End-to-end Solution map of Smart Services Solution

The Smart Services IS & Comms solution for the pilot will consist of new applications as well as existing applications that will be integrated to provide an end-to-end solution.

The gaps and high-level effort to enhance and integrate existing applications to meet the requirements of the Smart solution have been provided in Exhibit 9 Gap analysis document.


Conceptual Technical Model (CTM)
Home Automation
Advanced appliances
RF
Smart Meter Network
Meter
WAN
Substation
FIREWALL
S2 Meter Data Management Services
AMI Head End
Head-end Software
Head End Repository
Back office Integration software
Meter Data Management
MDM Database
MDM Software
Customer Systems
CRM / Customer Services
Customer support software
Billing/Tariff
Customer Database
Billing software
Customer Facing Solutions
National Grid Web Portal
Web Presentation
Web Content
Web Solution
Messaging / Mobile Devices
Data Warehouse & Business Intelligence
DataWarehouse / Data Marts / OLAP
S4 Enterprise Application and Data Integration & BPM
Modules
Energy storage
Plug-in Hybrid Electric Vehicles (PHEV)
Distributed generation wind, solar (PV)
Micro grid
Breaker
PV power generator
Micro grid controller
Diesel generator
Battery storage
Power demand
Capacitor control
Switch Control
Line Recloser
Smart Grid
S3 Grid Data Management Services
SCADA
SCADA software
Grid Data Management
Grid Database
Grid Data software
Grid Data Analytics
Analytics Repository
Analytics software
Back Office Applications
GIS
Geo-spatial
Work Management
Work scheduling & Dispatch
Asset Management
Asset repository
ERP & Asset Accounting
Acc Payable
Acc Receivable
Process Modeling Tool

Attachment 12

Data Model

Table of Contents

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2. Overview of approach 2
3. High-level Conceptual Data Model 2
4. High-level Conceptual Data Model for Meter Data Management. 4

1. Purpose of Document

The purpose of this document is to identify the high-level technology agnostic conceptual data model from a data perspective that has enterprise applicability. The conceptual data model consists of various business entities and forms the basis for further understanding of the business semantics of the various operational areas within the organization. It is in the form of an entity relationship model (ERD) which helps understand and capture the business knowledge from a data perspective. The ERD further helps breakdown the various business entities into atomic levels for the logical and physical data models. The document denotes the envisaged state of the enterprise data and is meant to provide an understanding of the various data areas that span multiple systems across the enterprise.

2. Overview of approach

The below conceptual data model is created based on envisioned future state of the Smart Services program and includes the data subject areas from the current systems and future business entities that will form the end solution. Industry standard methodologies and data modeling best practices were used to create the data model.

3. High-level Conceptual Data Model

The following notations are industry-standard representations in Information Engineering for denoting relationships between entities as identified below in the conceptual data model.

 - Zero or more occurrences

 - One of more occurrences

 - One and only one occurrence

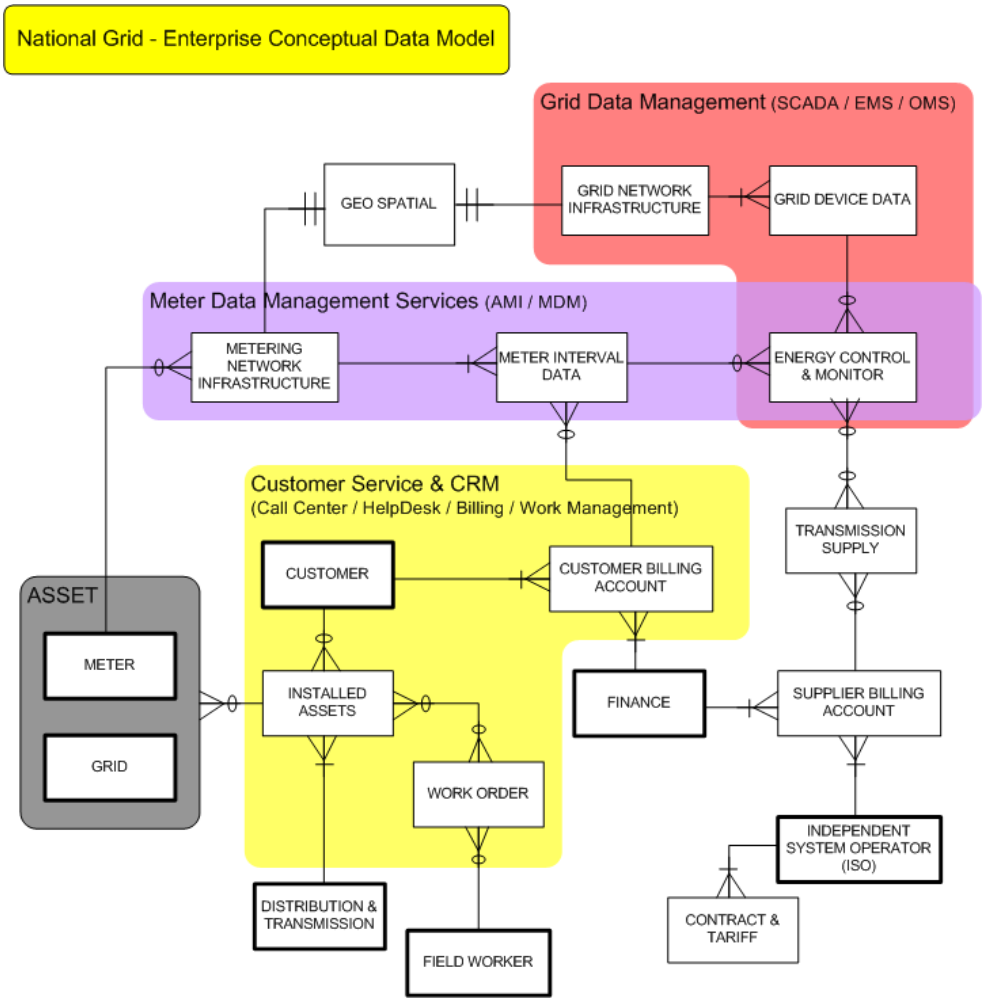
For example in the diagram below

- “CUSTOMER” may have one-or-more “CUSTOMER BILLING ACCOUNT”

The principle behind design of the conceptual data model is NOT to identify any business processes, but rather only the data needs of the organization. Its function is to show the relationships between the various business entities. For example a data feed from one system to another is not documented in this model. Such representations would be part of the process-flow diagrams.

Also as these business entities are at a much higher level, a conceptual data model does not indicate any data attributes. Data attributes are captured in the logical and physical data models which are achieved by further drilling down from the conceptual data model.

While the logical data model can be created at an enterprise level to represent every single data attribute required across the enterprise, the physical data model breaks down to application / system specific level. A general real-world scenario involves data attribute specific logical and physical data models.



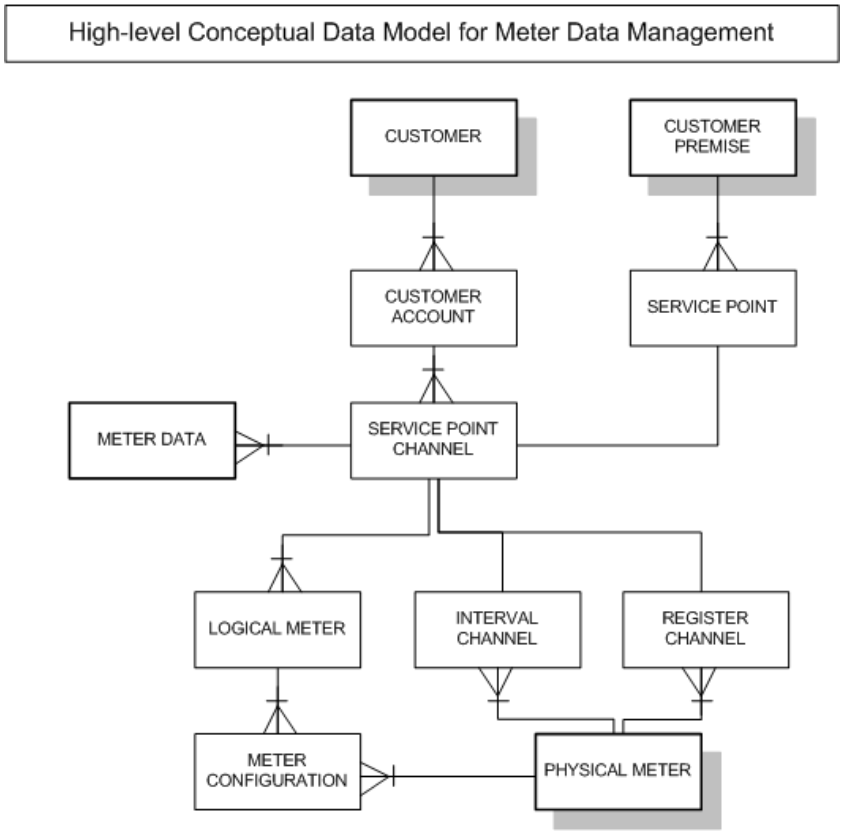
The various business entities are detailed below:

1. Customer – This is the residential, commercial or industrial customers who are National Grid's
2. Customer Billing Account – This represents the billing information for customers and all related activities tied to CRM
3. Meter Interval Data – This represents the customer power consumption (interval data) as recorded by the meters
4. Metering Network Infrastructure – This represents the Advanced Metering Infrastructure (AMI) of installed asset base
5. Asset
    a. Meter – These are the meter assets at National Grid

   b. Grid – These are the grid device assets at National Grid
6. Geo-Spatial – Represents the geographical co-ordinates of the location of each asset in the field
7. Grid Network Infrastructure – This represents the near real-time (SCADA) grid device level information acquired from the field
8. Grid Device Data – This represents the interval data received from the field devices rolled up to measureable information
9. Installed Assets – This represents the customer-to-meter cross reference as well as the grid devices installed in the distribution and transmission grid.
10. Work Order – this represents all installation and maintenance work orders created for all residential and C&I.
11. Field Worker – This is the representation of the internal or contracted field worker working in the field
12. Finance – This represents the Accounts Receivables and Accounts Payables for the company and all other information pertaining the installed assets
13. Independent System Operator (ISO) – This is the supplier of power that National Grid contracts with
14. Contract & Tariff – This represents contracts and tariffs agreed with the ISO for purchasing of power for distribution
15. Supplier Billing Account – This is the billing account information for the ISO
16. Transmission Supply – This represents the power supplied details as purchased from the ISO
17. Energy Control and Monitor – This represents all data that monitors and controls energy demand by customers and supply by power suppliers

4. High-level Conceptual Data Model for Meter Data Management

A conceptual data model for only the Meter Data Management shown below illustrates some of the relationships between the various physical elements of the solution.


High-level Conceptual Data Model for Meter Data Management
CUSTOMER
CUSTOMER PREMISE
CUSTOMER ACCOUNT
SERVICE POINT
METER DATA
SERVICE POINT CHANNEL
LOGICAL METER
INTERVAL CHANNEL
REGISTER CHANNEL
METER CONFIGURATION
PHYSICAL METER

Attachment 13

INTEGRATION OUTLINE

1 Purpose

The delivery of an IS Solution for National Grid's Smart Program will impact existing applications and introduce new applications to the IS landscape. The majority of these applications are expected to involve the sharing of data or the connecting of processes. As a result, application integration is critical for an end-to-end solution.

The Application Integration solution will build interfaces to cater to new and existing (legacy) applications around an Enterprise Service Bus (ESB). A Common Messaging Model based on CIM (Common Information Model – IEC 61968/61970) will be utilized for the messages passed to and from the various applications on the ESB.

Business Process Management will be utilized to capture and track sub-second, near real-time information on the processes being managed, and will also monitor and track events as they occur on the ESB.

The solution architecture identifies the existing interfaces requiring modification. It also identifies at a high-level the estimated number of interfaces to be built and recommends the next steps to be completed prior to moving into the detailed technical design phase.

2 Integration Scope of the Program

Application Integration is defined as "sharing or connecting processes and/or data between applications." The key areas in scope of Application Integration for National Grid's SMART Program are:

1. Area-1: Integration among the New Applications introduced as part of the Program. It broadly includes two sub-areas – Smart Metering and Smart Grid
2. Area-2: Integration of the New Applications (introduced as part of the Program) with Existing Applications within National Grid. The list of key existing applications includes Enterprise Asset Management, Work Management, Mobile Workforce Management, Billing and Payments, Customer Services, Portal, Distribution Management System, Outage Management System, Management Information and Business Intelligence
3. Area-3: Modifications to Existing Integration between the Existing Applications within National Grid. It includes changes to existing interfaces such as adding new data entities to share across existing applications

4. Area-4: Business-to-Business (B2B) Integration. It includes Integration (or service) end-points at the boundaries of National Grid to provide an Integration platform for data and information sharing between National Grid and the External Parties

The area highlighted in red in the diagram below depicts the scope of Application Integration for the Program.

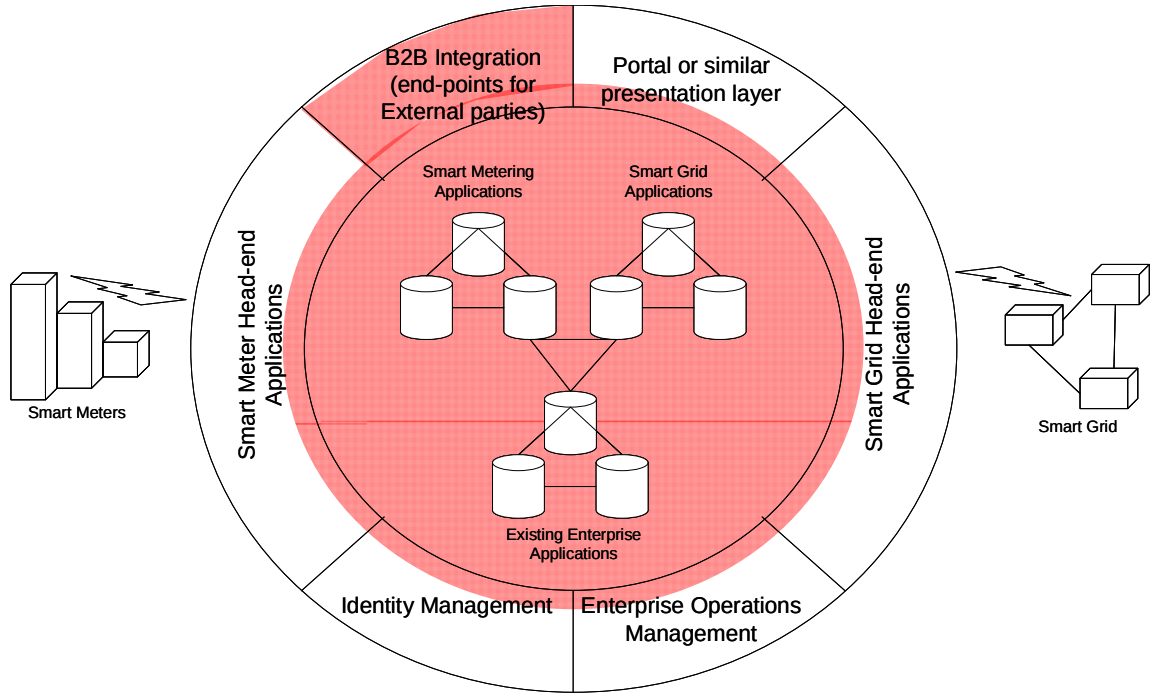


Figure 1: Scope of Application Integration

The list below highlights the areas considered outside of the Application Integration scope based on the Conceptual Technical Model for the Program.

- Communication between the various field (or home) devices within the Home Area Network (HAN), Local Area Network (LAN) and Wide Area Networks (WAN)
- Communication between the HAN, LAN and WAN
- Communication between the various field (or home) devices and the Smart Meter Head-end applications
- Communication between the various field (or home) devices and the Smart Grid Head-end applications
- Communication between the various field (or home) devices and the Data centre applications such as mobile messaging, emails and others

- Provision of a Portal or any similar visual presentation layer. However, the scope includes the integration of relevant applications to a Portal or to any similar visual presentation layer (covered in Area-1 and Area-2)
- Integration at the end-points that reside outside the boundaries of National Grid i.e. end-points on B2B applications or systems hosted and maintained by External Parties

3 Integration Scope of the Program

The scope of Application Integration for the Program includes:

- Area-1: Integration among the New Applications introduced as part of the Program. It broadly includes the following:
    - Smart Meter AMI Head-end system(s)
    - Meter Data Management System(s) (MDM)
    - MDM Billing engine
    - Smart Grid Head-end System(s)
    - Home Automation System
    - Home Automation Head End
    - Distribution Management System
    - Outage Management System
    - SMART Portal
    - Grid Repository
- Area-2: Integration of the New Applications (as listed above) with Existing Applications within National Grid. The list of key existing applications includes:
    - Customer Services suite (CSS)
    - Energy Resource System (ERS) – Meter Data Repository
    - Geographical Information System (GIS) – SmallWorld
    - STORMS – Work Management System
    - MITS – Meter Asset repository
    - PEOPLESOFT
- Area-3: Modifications to Existing Integration between the Existing Applications within National Grid. It is likely to include changes to existing interfaces around:
    - Customer Services Suite (CSS) including Customer Billing, Tariff, Presentment and support

- ERS
- MITS
- STORMS
- GIS

The list below highlights the areas considered out of scope for the Program:

- It is understood the following business functions will be serviced through existing capabilities/systems or will be carried offline. Hence, there are no requirements identified for any new, or modifications to existing, application integration around these business functions. These include:
  - Procurement and Logistics - to be offline
  - Mobile Workforce Management –to use existing interfaces with Work Management or through the External Meter Installation Vendor
  - Sales and Marketing - to be offline
  - Shared Services such as Finance, HR and others - to be offline
- Area-4: Business-to-Business (B2B) Integration i.e. Integration (or service) end-points at the boundaries of National Grid to provide an Integration platform for data and information sharing between National Grid and External Parties

4 Principles for Application Integration

The table below lists key application integration principles and associated rationale.

Ref.	Principle	Rationale
P1	**Plan for Integration and Plan for Growth in Integration** Application Integration must be started early in the Project and included in Project Plan. All the key deliverables of the Solution Delivery Process must be associated with Application Integration. IS must plan, design and build the Application Integration to cater to known future growth and expansion of Integration.	Application Integration is typically considered too late, during the build stages of the Solution Delivery Process. This results in missing interfaces or poor quality interfaces such as Point-to-point (P2P) that are built and deployed quickly. Adherence to this principle results in robust, complete and more cost-effective Application Integration. It would also enable a quicker response for future growth and expansions.
P2	**Proven Standards and Technologies**	Assists in easier integration among heterogeneous platforms and systems

	Application Integration must be delivered on proven standards-based technologies. The customization of the chosen products should be kept to a minimum.	common in the present technical landscape. Avoids dependence on small or underperforming vendors and reduces associated risks. Provides for ease of maintenance and offers flexibility and adaptability in product upgrade or replacement scenarios.
P3	**Use of Service Oriented Architecture** Application Integration must be based on Service Oriented Architecture (SOA) to the maximum extent possible	A Service Oriented Architecture Approach to Application Integration enables integrating diverse, heterogeneous applications developed in different architectures and programming languages and on different platforms. The interfaces delivered (on SOA) should be loosely-coupled, interoperable, self-describing and offer enhanced flexibility to accommodate the modifications resulting from changes to Host Applications.
P4	**Minimal Impact on existing Applications** Application Integration should avoid changes to existing Applications requiring integration. When this is not possible, changes to existing applications should be kept to a minimum.	Changes to existing applications typically result in additional effort and cost, leading to project delays, increased maintenance, and can lead to instability.
P5	**Data Security and Protection of Information** Application Integration must be implemented in adherence with policies and laws on Data Security and Protection of Information. Data and Information must always be protected against unauthorised access, modifications and Denial of Service	Assists in safeguarding critical and sensitive data associated with internal business departments, business partners and end-consumers (public). Enables compliance with regulatory and other government requirements. Ensures data integrity and increases the confidence of stakeholders and other interested parties.
P6	**Total Cost of Ownership (TCO)**	Enables a model where investments in

	The Total Cost of Ownership (resulting from Delivery, Infrastructure, Deployment, Operational Support, Upgrade, Replacement and Migration) for Application Integration must balance the benefits and costs associated with Growth in Integration, Flexibility to Change or Enhance, Scalability and Ease of Use	Application Integration are justified with direct benefits to businesses and cost-minimization against future enhancements and growth in integration. Enables improved planning and decision-making via greater visibility of investments associated with Application Integration while delivering quality solutions.
P7	**Change Management** Application Integration must follow procedures and conform to policies as set by Software (or Code) Configuration and Change Management (SCCM)	Software (or Code) Configuration and Change Management is followed for managing Host Applications. However, it is not followed for Application Integration. SCCM is important for Application Integration as the number of interfaces and the applications reliant on those interfaces are increasing.

Table 1: Application Integration Principles

5 Architecture Building Blocks

The Building Blocks of an Application Integration Architecture specify (or define) individual services and the relationship among those services required to enable Application Integration.

The diagram below depicts the organization of various building blocks of an Application Integration Architecture for the Program.

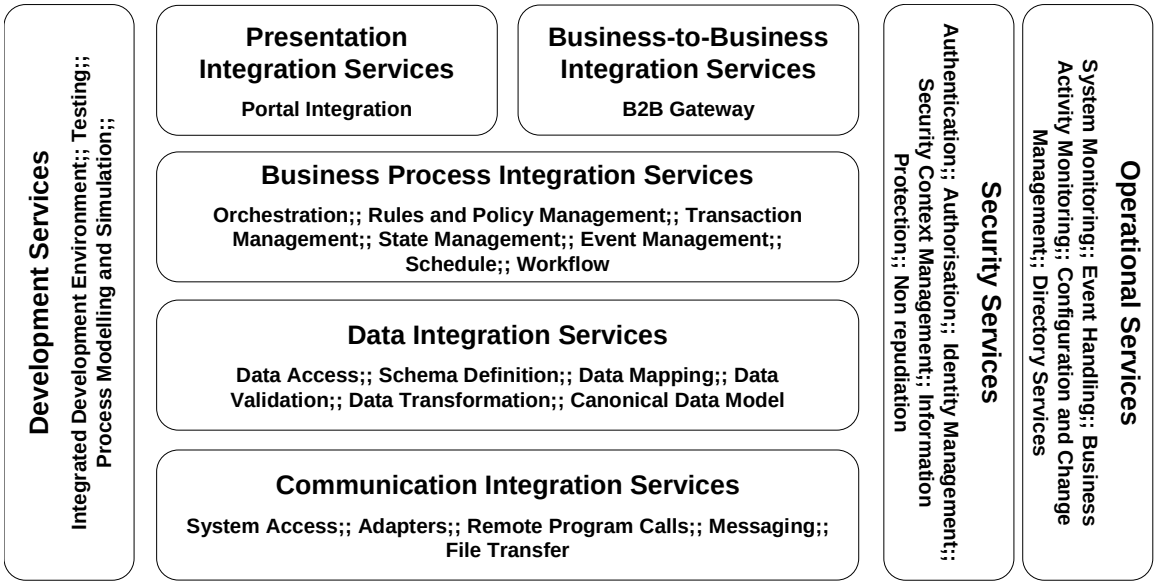


Figure 2: Architecture Building Blocks

6 Proposed Application Integration Solution

The Integration for the Program will utilize an Enterprise Service Bus built on the principles of Service Oriented Architecture (SOA). This will aid in integrating distributed components/applications seamlessly.

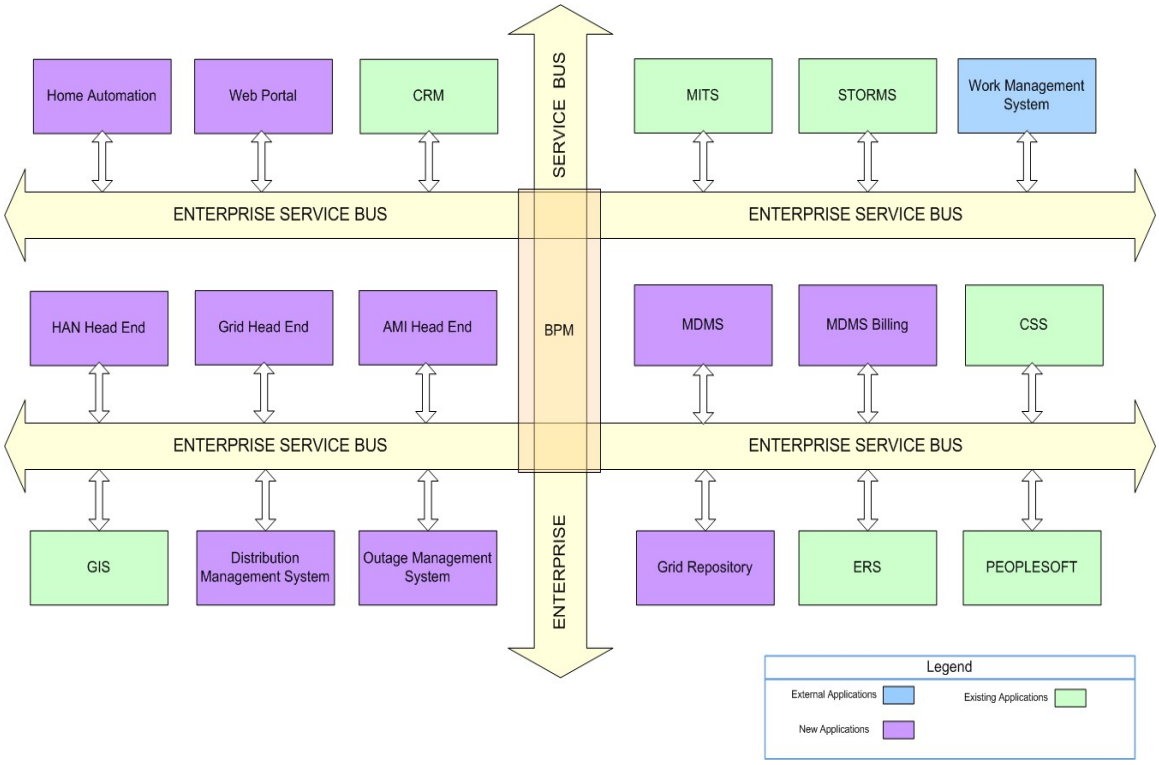
In the architecture using an ESB infrastructure the applications are connected through a communication back bone which facilitates message transfer between the source and target systems involved. The advantages of this approach are:

- Security - the communication is only via the backbone,
- Combining – the ESB combines the power of all previous integration approaches:
    - Is standards-based, scalable, and reusable
    - Supports heterogeneous communication mechanisms like synchronous, asynchronous, event based etc.
    - Can support the integration needs of legacy and new systems

It is also the intent to use a Common Message Model for the messages flowing on the ESB. This will ensure messages on the bus can be utilized by applications connected to

the ESB in the future, reducing the time and effort required to integrate new applications. The Industry standard (IEC 61968 & 61970 CIM) will be used for implementation, based on the level of support for the standard provided by the selected vendor products.

The following diagram depicts the SMART Program application landscape utilizing an ESB/BPM to achieve the Integration requirements as required by the project.



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Attachment 15

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