08-999-05

ROCKY MOUNTAIN POWER'S VIEW OF AUTOMATED METERING AND SMART GRIDS

1 Introduction

There is increasing interest in advanced metering and how it can help electric utilities meet the needs of future regulatory changes and customer expectations. The installation of an advanced metering infrastructure (AMI) system as the basis for movement to a smart grid is paramount to the future success of all large electrical utilities. However, with the continuing advances in AMI and supported technology, all utilities must consider the magnitude of risks associated with venturing into this realm. Mobile automated meter reading can still provide a low-cost and viable option for gathering monthly meter reads for billing purposes without the significant capital costs associated with AMI.

2 Metering Technologies

Technologies for automating meter reading are generally classified into three categories: automated metering, advanced metering and smart metering. For the purposes of this paper, the following definitions will be used:

2.1 Automated Meter Reading

Automated meter reading (AMR) systems are typically defined as a system that only automates the manual meter reading process. These systems deliver accurate and reliable monthly meter readings to billing on a cycle basis at a cost typically lower than manual reading methods. Mobile or drive-by systems are the most commonly implemented automated meter reading solutions in the industry.

2.2 Advanced Metering

Advanced metering systems (commonly referred to as AMI) provide the same metering data levels as automated meter reading systems and are also capable of delivering interval data from all meters. This interval data can be used for time-based rates and critical peak pricing programs with the proper IT billing systems in place. These systems also provide additional benefits in the form of outage detection and restoration messages via the system. Demand response programs can be implemented indirectly with direct load control through a separate system (e.g. paging, etc.) and the impacts measured with the advanced metering system.

The Federal Energy Regulatory Commission has defined AMI as *"a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point. AMI includes the communications hardware and software and associated system and data management* *software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to customers and other parties such as competitive retail providers, in addition to providing it to the utility itself."*[1]

Note that "Smart thermostats" and "Home Area Networks" are not a required component of AMI as defined by FERC, although they offer benefits for demand response in addition to those possible with AMI-supported time-varying pricing alone. Also, control of distribution equipment (reclosers, sectionalizers, capacitors, etc.) is not a required component of AMI. In combination, these additional features begin the framework for a "smart grid".

Many utilities, including Rocky Mountain Power, intend to mitigate the risk of stranded investments by installing mobile systems with the ability to migrate to fixed networks that offer advanced metering capabilities. Systems of this nature do not have the capability to enable the functions associated with smart grid (see Smart Metering below).

2.3 Smart Metering

Smart metering systems provide the highest level of meter reading automation and can integrate demand response, outage management, and transmission and distribution asset management. These systems have the capability to offer an "in-home display" of information to customers and integrate direct load control where the utility sends signals to cycle loads (e.g. A/C, water heaters, etc.). Furthermore, these systems are capable of integrating indirect load control where the utility sends pricing signals and consumers can program the behavior of their individual appliances for response to changing prices. Automated meter reading, and most advanced metering systems, cannot be migrated to a smart metering system.

3 Metering System Requirements

The advanced or smart metering system becomes the central nervous system for smart grid and any additional functionality is built upon the communications infrastructure installed during the initial deployment of smart meters. This central nervous system is utilized by other systems to deliver all desired benefits of the smart grid. With the longevity of the meters and the local communications installed as the foundation of the smart grid, it is imperative that the proper system be selected.

The following requirements are the minimum acceptable standards for an advanced metering system deployed at this time:

- High speed, low latency, communications infrastructure with two-way communication to all meters and endpoints. The communications must be either IP addressable or in a FCC licensed band.

[1] FERC Staff Report, July 2007, Appendix A (Glossary)

- Electric meters that are capable of recording and reporting daily usage with a minimum of one-hour intervals and have an internal service control switch to connect and disconnect service on those meters from a remote location.
- Proven inter-operability with distribution automation switches and devices, electric revenue meters, demand-side management switches and devices and home area networks.

"Transmission and distribution technology is going to evolve to integrate the demand side and energy efficiency resources. This evolution is already in place today through AMI and smart grid initiatives; however, the next three to five years will be critical to fully realize the potential of this integration."[2]

4 Smart Grid

Whereas the FERC definition of AMI does not include smart thermostats or home area networks, the full capabilities of a smart grid as defined in the Energy Independence and Security Act of 2007 cannot be achieved without these strategic components:

- Daily interval usage data – provides the basis for complex time-of-use billing structures.
- Outage detection and restoration notification – allows for real-time polling of meters within a defined geographical zone to detect outages and allow for better crew management during restoration activities.
- Remote disconnect and reconnects – the ability to connect and disconnect electric service from a remote location.
- Demand response – through direct control of customer's appliances.
- Demand side management – through active pricing signals upon which customers can control appliances either manually or through automated home networks.
- Distribution automation – including asset monitoring and reporting including transformer monitoring, fault detection, etc.

"While incremental measurement and sensing features may evolve in various apparatus, the greatest and continued change will be in the integration of the communication technology in the transmission and distribution equipment. As the grid has more connected devises to provide information, the operational IT applications will grow from reporting and command to predictive analysis and automatic control of equipment."[3]

It is important to note that most advanced metering systems do not have the capability to migrate to a true smart metering system that supports smart grid without major enhancements to the meter endpoints and the communication infrastructure. It is

---

[2] Bud Vos, Vice President, Marketing, Strategy and Regulator Affairs, Comverge

[3] Sharon Allan, president, Elster Integrated Solutions

critical that any investment in an advanced metering system be done only if the system can migrate to a smart metering system.

5 Regulatory Environment

While there is a large amount of activity at the federal and state levels, there are only a few pieces of legislation that may have an immediate impact on electric utilities and their decisions regarding automated meter reading, advanced metering and smart metering.

Complete benefits of an advanced metering system, and ultimately a smart grid, is dependent upon changes in the regulatory arena in how customers pay and electric utilities are compensated for substantial increases in fixed costs. Smart grid and other energy management systems, when fully implemented, increase utilization of generation, transmission and distribution assets and simultaneously reduce the on-peak consumption of electric energy and encourage overall reduction of usage by customers. Rate structures that place the recovery of fixed costs in usage charges create a situation where the more a customer benefits most from smart grid technology the less they pay for it. Such rate structures also create volatile revenue streams and put utility cost recovery for these systems at risk.

The national focus on advanced metering started with the Energy Policy Act (EPAct) of 2005 and changed dramatically with the passage of the Energy Independence and Security Act (EISA) of 2007. The focus for most manufacturers at that time was the development and marketing of advanced metering solutions. Their belief was that the regulatory structure would change dramatically and require advanced two-way metering communications. Even with this emphasis, the technology is still immature and developments are forthcoming.

With the amendments to EISA 2007 made by the American Recovery and Reinvestment Act of 2009, the focus shifted to smart grids and the promise of stronger business cases. Those amendments must now be incorporated into a composite business case to ascertain the benefits to the electric utilities and their customers before any decision can be made to pursue any grants or federal funding.

6 Timing of Deployment

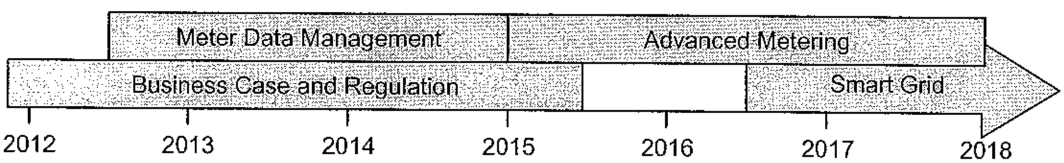
There are currently several working groups developing standards for the entire spectrum of equipment, devices and end points for the metering and smart grid systems, including interoperability of components. The Energy Independence and Security Act of 2007 has specified that the Department of Energy champion this effort with a completion date of 2012. These standards, along with industry adoption, are crucial to the mitigation of risks associated with implementation and deployment of the magnitude required for Rocky Mountain Power.

With the current state of standards development, local commission activity, and emerging market leaders, it is not prudent to invest in any form of advanced metering system at this time.

With the amount of capital investment required, it is essential that the market leaders be identified, system interoperability be verified and other electric utilities absorb the development risk before a venture into this technology is begun. With large scale deployments beginning in California, Texas and Ontario and a myriad of pilots throughout the country, the market leaders will become self-evident within the next few years.

Due to the time requirements for preparation of the business case, regulatory approvals and vendor selection, which can take upwards of three years, it is necessary to begin working in those areas at the outset of the project. For planning purposes, it is necessary to begin development of the meter data management system in advance of any meter installations. When completed, a pilot installation of an advanced metering system would precede any full deployment to test system and IT functionalities.

The following timeline shows a recommended deployment schedule based on the current state of system requirements, technology development and regulatory inquiries.



This timeframe for smart grid is provided for informational purposes only and begins with continued research and financial analysis for distribution and demand response applications that can be supported by the advanced metering communication system. This is an ongoing analysis that investigates the emerging technology and feasibility of those systems. As the individual technologies become technically proven and financially viable, they would be implemented in a manner consistent with the company's goals and operational plans.

"The digitization of the electric grid begins at the meter." [4]

7 ATK Smart Grid Project

A recent press release stated "ATK Launch Systems, a division of ATK, is teaming with Rocky Mountain Power and P&E AUTOMATION to develop, deploy, and

[4] Don Cortez, Vice President of Regulated Operations Technology, CenterPoint Energy

demonstrate a 2.5 megawatt integrated, fully automated distributed generation (DG) and storage system."

Rocky Mountain Power has partnered with ATK in a utility advisory role. We have attended design meetings regularly to advice on such issues as interconnecting the generation to the utility transmission grid, practicality of dispatching the generation, utility to customer communications, and potential demand side program application.

The five-year project will demonstrate an integrated system of diverse renewable generation and energy storage technologies, including wind, steam, recovered energy, and a novel compressed-air generation/storage technology.

In addition to the DG demonstration, the project includes an R&D effort to develop and implement a unique customer-owned DG monitoring/control system and a utility-customer gateway for behind-the-meter visibility and information exchange between the utility and customer.

The first phase of the project is slated for 25 kilowatts with an ultimate output of 2.5 megawatts of integrated renewable DG. It is planned that the full demonstration project will reduce the peak load on the substation by 15%.

Rocky Mountain Power has no plans to make any investments to our current infrastructure to accommodate this project because of its small production output and due to its nature as a demonstration project. We will however continue to support this project in an advisory role and continue to monitor for the potential to apply any current demand side programs to the project.