DRAFT – REVISION 1

Smart Grid Business Case Analysis

Prepared For

Rochester Public Utilities

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August 2010

Project 55060

Burns & McDonnell
SINCE 1898

Smart Grid Business Case Analysis

prepared for

Rochester Public Utilities
Rochester, Minnesota

August 2010

Project No. 55060

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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EXECUTIVE SUMMARY

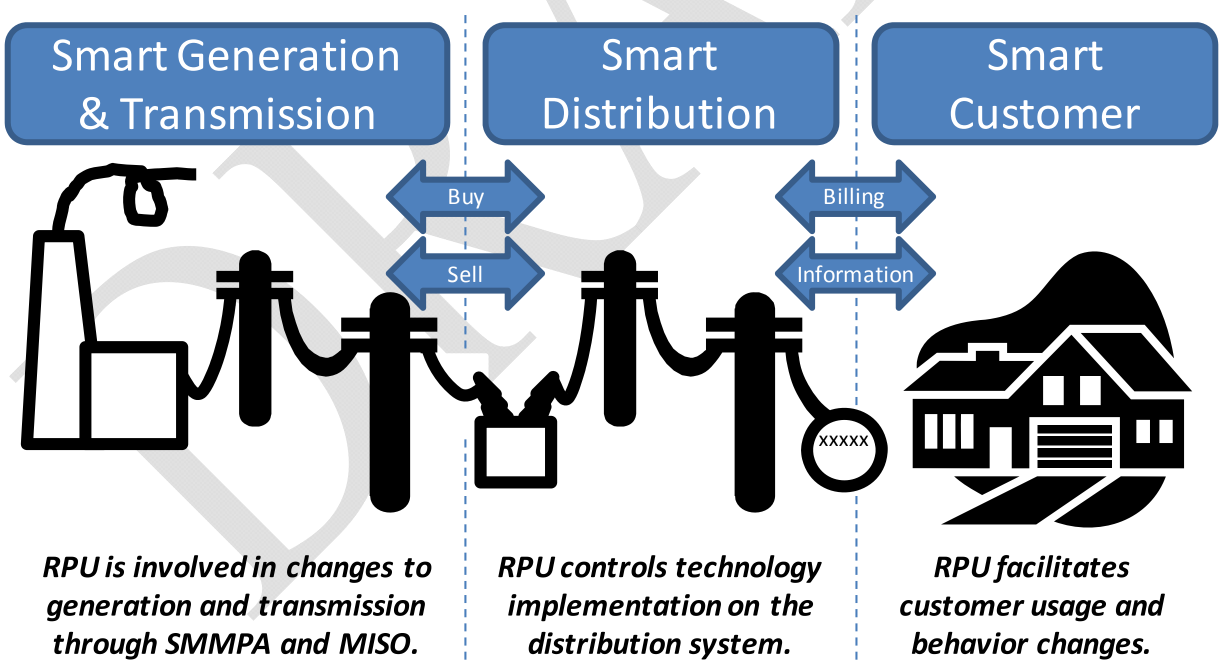
ES.0 EXECUTIVE SUMMARY

ES.1 RPU SMART GRID VISION & OBJECTIVES

Many of the technology and customer service enhancements that Rochester Public Utilities (RPU) has already undertaken are elements of the Smart Grid concept promoted by the federal government in the 2007 Energy Independence and Security Act. This study presents a review of the anticipated benefits that can be obtained from the use of increased digital data gathering and control systems at RPU. The benefits evaluated serve the RPU customers, the Rochester community, and the RPU organization directly.

The Smart Grid concept promoted by the 2007 Energy Independence and Security Act includes participation and transformation across the entire electricity supply chain from generation down to the end user. As shown in Figure ES-1, RPU is involved in Smart Grid implementation at the generation and transmission level, controls Smart Grid Implementation at the distribution level, and may encourage and facilitate Smart Grid activities and behavior on the customer side of the meter.

Figure ES-1: Smart Grid Participants



RPU and Burns & McDonnell have reviewed anticipated benefits that may be obtained from use of increased digital data and control systems. The benefits can be categorized in the following areas:

- RPU Customers
  - Improved reliability and reduced service outage duration
  - Outage and power quality monitoring for each customer
  - Empowerment to reduce energy usage and energy costs
  - Improved customer service and more energy choices
  - Increased detail of energy usage information
- Rochester Community
  - Reduced regional GHG emissions
  - Increase in local technical jobs
  - Improved local business climate and energy support for new businesses
- RPU Operations & Efficiency
  - Improved voltage management and conservation
  - More efficient and effective dispatch of field crews
  - Increased efficiency of personnel and the electricity delivery system
  - Reduced maintenance expenses

The discussion of these benefits led to the development of the RPU Smart Grid vision statement:

> *"RPU will prudently adopt Smart Grid technologies which provide customer value in reliability or service."*

Technology implementation and advanced service offerings support the vision developed by RPU including potential changes in the following major areas of the RPU system:

- Engaging and empowering customers to manage their energy bills
- Enhancing the metering of customer electricity usage
- Improving and automating the distribution system, increasing reliability
- Expanding the enterprise data management systems to increase data storage and sharing
- Implementing a communication system to facilitate data flow in real-time
- Implementing appropriate system security to prevent internal or external intrusion or misuse

Successful Smart Grid implementation requires a joint effort between utilities and customers to fully manage load and maximize efficiencies.

It will take time to overcome the national and local inertia of current utility and customer operating cultures and transform to a new way of operating that is more focused on data and customer participation.

But utilities are realizing that more information gathering, analytics, and sharing can lead to improved operations and service to customers. Many of RPU's Smart Grid objectives are dependent on customers' demand for energy information, energy choice, customer service, and improved reliability. RPU intends to gain information regarding customer preferences prior to setting specific objectives and goals regarding technology implementation on the RPU electricity distribution system.

ES.2 RPU SMART GRID GAP ANALYSIS

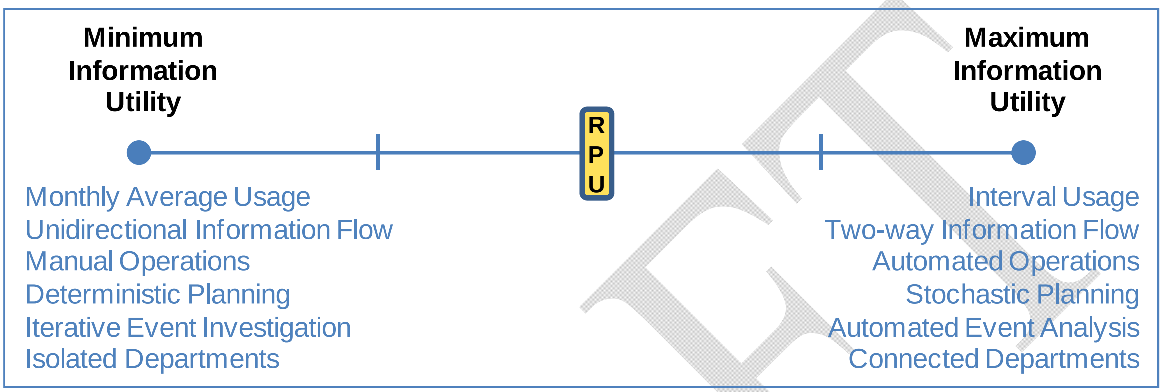
RPU operates a modern and reliable electricity distribution system that is already capable of Smart Grid functionality as demonstrated by the RPU Smart Grid scorecard in Table ES-1.

Table ES-1: RPU Smart Grid Scorecard

CATEGORY	UTILITY WITH **MINIMAL** SMART GRID CAPABILITIES	**RPU** SMART GRID CAPABILITIES	CONVENTIAL WISDOM OF A UTILITY WITH **FULL** SMART GRID CAPABILITIES
CUSTOMER SERVICE	-MANUAL CONNECT & DISCONNECT -MANUAL POWER QUALITY REVIEW -OUTAGE REPORTS BY CUSTOMER CALL IN	-REMOTE CONNECT & DISCONNECT -MANUAL POWER QUALITY REVIEW -OUTAGE REPORTS BY CALL IN	-REMOTE CONNECT & DISCONNECT -REMOTE AND CONTINUOUS POWER QUALITY REVIEW -AUTOMATED OUTAGE DETECTION AT EACH METER
RANK:	*0*	*30*	*100*
CUSTOMER INFORMATION & CONTROLS	-MEASURE & REPORT AVERAGE MONTHLY USAGE -BILL ENERGY BASED ON AVERAGE MONTHLY COSTS -PROVIDE CUSTOMERS WITH MONTHLY STATUS/BILL	-OPOWER CUSTOMER USAGE COMPARISON REPORTS -AVAILABLE VOLUNTARY TOU RATE STRUCTURE	-MEASURE & REPORT HOURLY USAGE -DYNAMIC HOURLY PRICING -REAL-TIME AVAILABILITY OF HOURLY STATUS -TWO-WAY COMM. W/ HOME AREA NETWORK
RANK:	*0*	*40*	*100*
LOAD UTILIZATION	-NONE	-DIRECT LOAD CONTROL PROGRAMS -DEMAND RESPONSE PROGRAMS	-DEMAND RESPONSE MARKET BIDS -UTILITY & CUSTOMER CONTROLS -ANCILLARY SERVICES
RANK:	*0*	*40*	*100*
DISTRIBUTION AUTOMATION	-MANUAL SWITCHING -NON-PARALLELED DISTRIBUTED GENERATION -SYSTEM MONITORING & REMOTE CONTROL AT SUBSTATIONS	-AUTOMATED CAPACITOR BANK SWITCHING -SCADA SYSTEM CONNECTING ALL SUBSTATIONS -INTELLIGENT RELAYING	-AUTOMATED SWITCHING -MICROGRIDS -LOAD MONITORING ALONG FEEDERS -LOAD MONITORING AT DISTRIBUTION TRANSFORMERS -MONITORING & CONTROL AT EACH ASSET/DEVICE -AUTOMATED OUTAGE ISOLATION
RANK:	*0*	*60*	*100*
ASSET MANAGEMENT	-ASSET MANAGEMENT AT SUBSTATION LEVEL -NO SCADA -DETERMINISTIC PLANNING -STATIC ASSET RATINGS	-SCADA SYSTEM CONNECTING ALL SUBSTATIONS	-MONITORING OF DISTRIBUTION-LEVEL TRANSFORMERS -AUTOMATED ADVANCED ANALYSIS OF SCADA DATA -STOCHASTIC PLANNING -DYNAMIC ASSET RATINGS
RANK:	*0*	*60*	*100*
RELIABILITY	-REACTIVE CORRECTIVE ACTION -EVENT REPORTS BY CUSTOMER CALL IN -GENERAL IDEA OF EVENT LOCATION -MANUAL RESPONSE PLANNING & EXECUTION -MANUAL SYSTEM RECONFIGURATION -ELECTRO-MECHANICAL RELAYS	-OUTAGE MANAGEMENT SYSTEM -COMPUTER RELAYS	-PREDICTIVE CORRECTIVE ACTION & EVENT AVOIDANCE -AUTOMATED OUTAGE DETECTION AT EACH METER -SPECIFIC & AUTOMATED LOCATION/CAUSE REPORTING -AUTOMATED OUTAGE ISOLATION -AUTOMATED CUSTOMER INFORMATION REPORTING -COMPUTER RELAYS
RANK:	*0*	*50*	*100*
ENTERPRISE	-MANUAL MONTHLY METER READING -AVERAGE MONTHLY USAGE INFORMATON -DETERMINISTIC ASSET MANAGEMENT -ISOLATED & LIMITED INFORMATION SHARING ACROSS DEPARTMENTS	-DRIVE-BY AUTOMATED METER READING	-REAL-TIME HOURLY USAGE -DYNAMIC TREND ANALYSIS FOR ASSET MANAGEMENT AND PREDICTIVE NOTIFICATIONS -REAL-TIME INFORMATION AVAILABLE ACROSS ALL DEPARTMENTS -REMOTE & AUTOMATIC METER READING
RANK:	*0*	*25*	*100*

As the scorecard demonstrates, RPU has made investments in technology have improved operational efficiency, improved service to customers, and have enabled RPU to provide customers with valuable information regarding their energy usage. These investments mean RPU is already marching down the path to becoming a maximum information utility (Figure ES-2).

Figure ES-2: Smart Grid Spectrum



RPU has an engaged customer base that already participates in conservation and load management programs. Customers are informed about available programs and choices through the RPU website, customer service inquiries, and bill stuffers. RPU has implemented OPOWER, a Smart Grid software program that informs residential customers how their energy usage compares to similar homes. OPOWER motivates customers to conserve and shift load to non-peak periods through a customer engagement approach. However, RPU could expand the services and choices offered to customers, particularly residential customers, by implementing technologies that provide customers with more detailed energy usage information and rate structures that promote energy and peak demand conservation.

Customer meters currently installed on the RPU system consist of a mix of electromechanical and solid state technologies. All electric and water meters are equipped with communication modules that enable RPU’s drive-by automated meter reading (AMR) system. To implement time varying rate structures, such as time of use (TOU) rates, advanced meters (smart meters) need to be installed to replace the current meters. Advanced meters will measure energy usage and power quality information on hour or shorter intervals, thus measuring both the quantity and timing of energy usage. RPU may also gain operational efficiency by implementing a wireless fixed communications network that will remotely read RPU meters as well as new smart meters. It will also enable more frequent meter reading, on demand meter reads, and real-time two-way communications with installed smart meters.

RPU has demonstrated high reliability of service to its customers as indicated by low outage times each year, however, automation and remote control on distribution lines and substation equipment throughout the system could improve reliability. Monitoring system power quality through smart meters, adding remote control and automation capabilities to capacitor banks, and adding remote control and automated switching equipment could enhance electricity delivery reliability by reducing the number outages, impact of each outage, and quicken RPU's response to outages.

Within the RPU operations center, customer data is managed by an advanced customer information system (CIS) and outage responses are managed by an advanced outage management system (OMS). However, RPU operates a distribution management system (DMS) that interfaces with RPU's SCADA system but does not have the capacity to capture, manage, and store interval customer usage information. To manage detailed customer usage information on a large scale, RPU will need to implement a meter data management (MDM) system that interfaces with its current back office systems such as CIS.

ES.3 RPU SMART GRID PATHS FORWARD

In order to determine whether RPU should deploy smart grid technologies and advanced meters to all customers depends primarily on the transition of rate payers to time of use (TOU) rates. If RPU expects to transition all rate payers to TOU rates, then all customers would require new advanced meters and an advanced metering infrastructure (AMI). If RPU plans to offer TOU rates to customers on a voluntary basis, then RPU would only need to implement advanced metering to those customers who volunteer to participate and to those that provide strategic informational benefits.

RPU and Burns & McDonnell have identified and analyzed the following two strategic paths by which to implement Smart Grid technologies on the entire RPU system (refer to Appendix B for a graphical representation of these paths):

1. **Mandatory Rates / Mandatory Technology:** This approach assumes that all RPU customers are required to transition to TOU rate structures. Transition of all customers requires the installation of advanced metering to all RPU customers and supporting communications and data management all within a four year deployment period.

2. **Voluntary Rates / Mandatory Technology:** This approach assumes that TOU rates participation will be voluntary but that RPU will eventually deploy advanced metering, along with supporting communications and data management, to all RPU customers within a 15 year deployment period. Voluntary TOU participants will receive advanced meters in order to enable TOU interval billing. Other locations will receive advanced meters early in the deployment period

based on strategic locations selected to provide power quality and outage notification information. Remaining customers will receive advanced meters through attrition, failure, and phased deployment throughout the 15 year deployment period.

Additional strategic paths have been identified by RPU and Burns & McDonnell that provide RPU customers with increased energy choice and access to Smart Grid technology but will not likely result in Smart Grid deployment across the entire system. For this analysis, these additional strategic paths were not evaluated in detail but should be considered viable paths forward for RPU:

A1. **Voluntary Rates / Voluntary Technology:** This approach assumes that TOU rates participation will be voluntary and that RPU would provide and deploy advanced metering to only those customers who participate.

A2. **Cost Share Advanced Metering:** This approach would provide advanced metering and compatible home energy displays to those customers who agree to pay a portion of the cost of the equipment and installation. By enabling customer access to real-time usage information through an advanced meter, both RPU and the customer may benefit from the usage data.

A3. **Customer Pays Advanced Metering:** This approach would provide advanced metering and compatible home energy displays to those customers who agree to pay the complete cost of the equipment and installation. RPU and the customer may benefit from the usage data collected.

A4. **Customer Access to Usage Information:** This approach is the least costly means of providing customers access to their usage information. It assumes no advanced metering is utilized but rather RPU will promote and facilitate customer adoption of devices that are capable of interfacing with their existing electricity meter to display near real-time home energy usage information. Capable devices are already on the market, such as the Cisco home energy controller, that can read the wireless information transmitted by the meter’s ERT module. These devices will also be compatible with advanced meters should they eventually be installed.

Although advanced metering is required in order to meter and bill customer usage on hourly or shorter time intervals, advanced meters also provide the utility and customers with additional features and benefits such as real-time usage information, power quality information, outage notification, remote connect/disconnect, and more. Therefore, this study and detailed business case analysis focuses on paths which deploy advanced technology to all RPU customers; the Mandatory Rates / Mandatory Technology and Voluntary Rates / Mandatory Technology approaches. Paths A1 through A4 provide customers with service options and access to usage information but do not provide RPU real-time status and health information across the entire distribution system.

Under the Voluntary Rates / Mandatory Technology approach, those customers interested in accessing their hourly usage information would be required to purchase a home energy display (HED) while RPU would deploy advanced meters based on TOU participation, strategic locations, attrition, failure and phased deployment. The smart meter will allow RPU access to the customer's usage and power quality information. RPU would also install a wireless fixed communications network capable of remotely reading both remaining standard meters as well as newly installed smart meters. Data management would also be upgraded to accommodate new interval metering data. Distribution monitoring, control, and automation would also be implemented to compliment advanced metering and would share communications and back office infrastructure.

Under the Mandatory Rates / Mandatory Technology approach, RPU would install smart meters to all customer locations in addition to a wireless fixed communications network to facilitate two-way communications with advanced meters. RPU's back office systems would be upgraded with locally implemented solutions and new processes would be developed quickly to address rapid changes to utility operations. Distribution monitoring, control, and automation would also be implemented to compliment advanced metering and would share communications and back office infrastructure.

ES.4 RPU SMART GRID COST BENEFIT ANALYSIS

Burns & McDonnell estimated the costs and the value of benefits under both the Mandatory Rates / Mandatory Technology and Voluntary Rates / Mandatory Technology approaches over a 15- year analysis period. Total cost of both approaches was estimated to be $21.4 million since similar equipment is deployed under each approach but across different timeframes and through different strategies. The Mandatory Rates / Mandatory Technology approach assumed deployment within four years while the Voluntary Rates / Mandatory Technology approach assumed deployment over 15 years.

The alternative voluntary paths described in the previous section were not analyzed in detail through a cost benefit evaluation. They represent methods for RPU to enable Smart Grid technology for those customers who are interested but are not expected to provide system-wide benefits.

Under the Voluntary Rates / Mandatory Technology approach, direct RPU benefits were estimated at $15.3 million, resulting in a simple payback greater than 15 years. Benefits to RPU Customers were estimated at $11.8 million. Under the Mandatory Rates / Mandatory Technology approach, direct RPU benefits were estimated at $18.9 million, resulting in simple payback greater than 15 years. Benefits to

RPU Customers were estimated at $21.2 million. Figure ES-3 and Figure ES-4 demonstrate expected cash flow results of net cost benefit analysis.

Figure ES-3: Net Cost Benefit Analysis Results (RPU Direct Benefits)

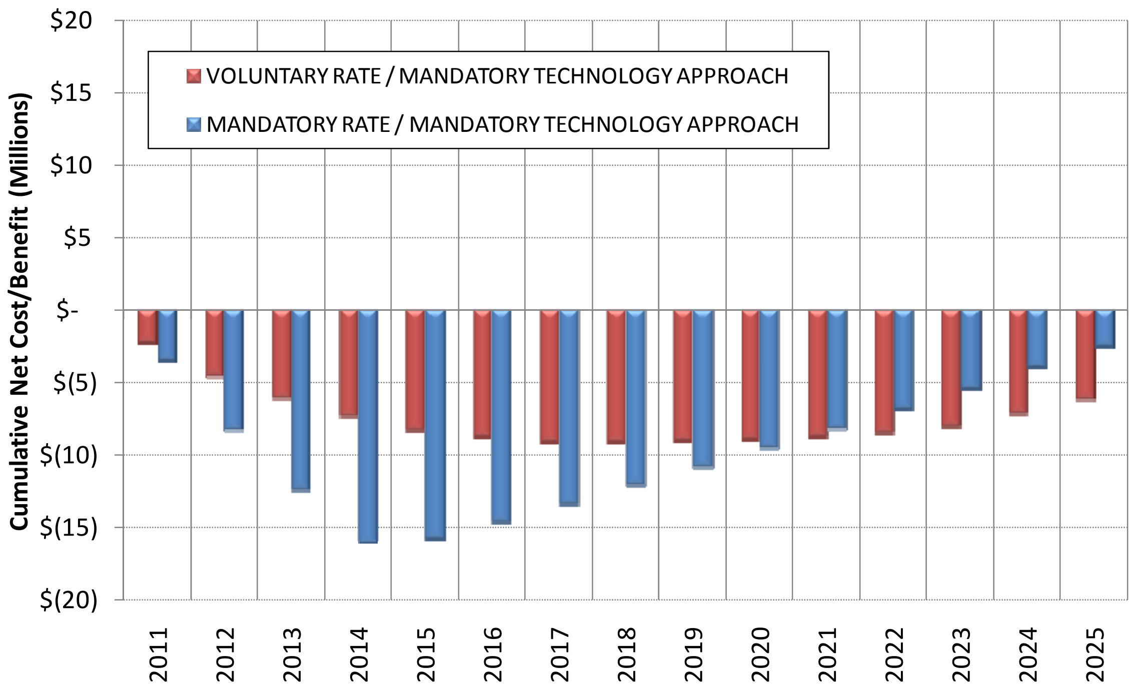
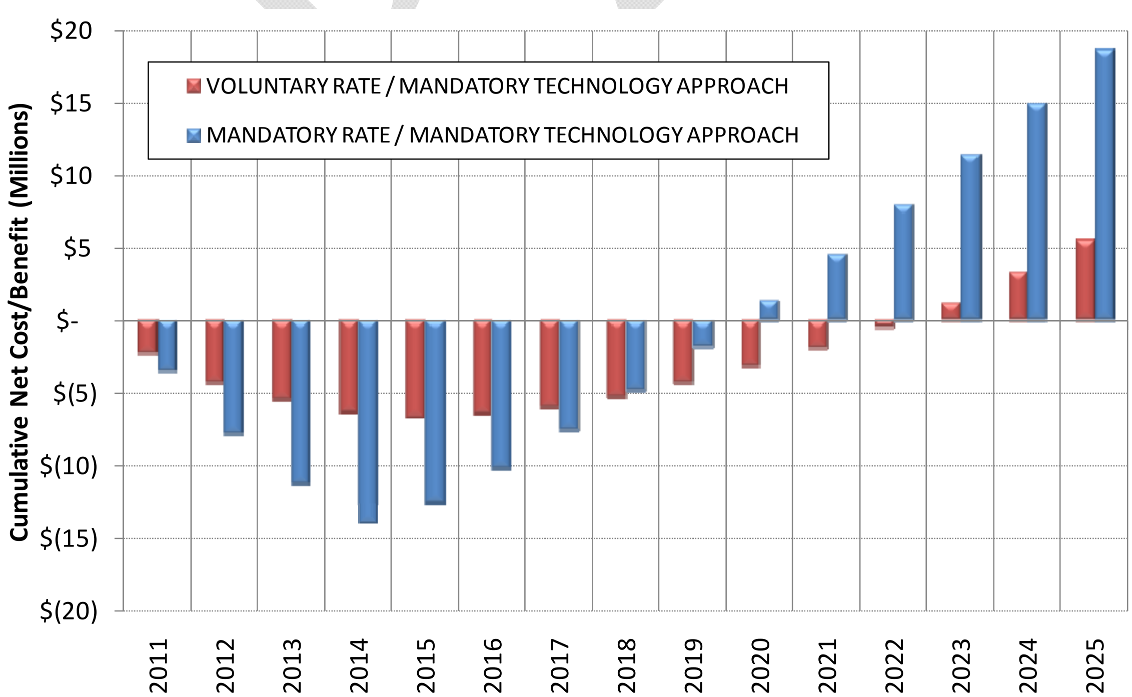


Figure ES-4: Net Cost Benefit Analysis Results (RPU & Customer Benefits)



ES.5 RECOMMENDATIONS

Based on experience and analysis, Burns & McDonnell recommends the following:

1) RPU should consider AMI technology (smart meters and communication network) as the best technology solution in order to achieve customer information and empowerment, power quality monitoring, outage detection, remote connect/disconnect, and demand side management capabilities. The alternative would be to pursue dedicated equipment for each function which would result in greater expense, less flexibility, and little to no future interoperability.

2) The industry is currently demonstrating that the average electricity consumer is not prepared to adopt TOU or any other time varying rate structures. More education and outreach must be accomplished to inform consumers on the costs to provide electrical service, how their behaviors impact that cost, and what they can do to reduce electricity consumption. Only after successful education should RPU consider mandatory TOU rate structures.

3) Future maintenance and upgrade activities on the RPU distribution system should support a long-term RPU Smart Grid vision. That is, upgrades and equipment replacements should consider technologies that will be compatible with RPU future Smart Grid objectives, should be scalable, and should be interoperable across vendors and other RPU systems.

4) Under either a voluntary or mandatory approach, RPU should consider the impacts of new quantities of information generated. The processes and capabilities to store and manage this data within the RPU information systems should be developed prior to field device installation.

5) Education and empowerment of the RPU customers may begin immediately. While RPU considers investment in technology and tools to improve system capabilities, education regarding the daily costs associated with generating and delivering electricity should begin immediately. Additionally, RPU could begin promoting the use of home energy information devices such as the Cisco home energy controller which can wirelessly read RPU’s current electricity meters (ERT compatible) and are compatible with advanced meters (ZigBee).

6) RPU should upgrade their CIS to SAP CRM. This upgrade will enable RPU to utilize and bill according to additional usage information that will be generated by future technology implementations.

* * * * *

SECTION 1

INTRODUCTION

1.0 INTRODUCTION

1.1 WHAT IS THE SMART GRID?

The Smart Grid has different definitions and implications depending on one's perspective.

- From a **Regulatory Perspective**, the Smart Grid mainly fosters grid stability and grid reliability on a national scale. However, Federal and State regulations also advocate customer rights to their own detailed usage information. For example, in Minnesota, the public service commission (PUC) is considering requiring regulated utilities to provide electricity purchasers with information relating to: time-based pricing in the wholesale and retail markets, specific customer usage information, and, on an annual basis, information on the source of the power provided by the utility to the consumer. The Minnesota PUC has also requested that non-regulated utilities provide reports to the PUC and participate in meetings just as regulated utilities are required.
- From a **Utility Perspective**, the Smart Grid will provide enhanced load forecasting, improved load control, and more efficient and automated operations. It will improve the utility's ability to manage load, distribution, and generation while providing improved power quality and service to its customers.
- From a **Customer Perspective**, the Smart Grid will offer detailed information about energy usage as well as enable greater choice and control over energy usage. This information and control may be utilized to reduce carbon footprint and reduce energy costs.

Regardless of the individual perspective, the utility must address both regulatory and customer expectations regarding Smart Grid investments and functionality. The utility must comply with regulatory and wholesale market requirements and must also manage delivery and cost of energy to each customer. Between transmission interconnection and customer homes, the utility has full authority and control over operations of the distribution system. However, it has no authority over the customer side of the meter, yet is expected to effectively accommodate and manage customer load. Therefore, a joint effort between utilities and customers to fully manage load and maximize efficiencies is required, regardless of the technological capabilities of a Smart Grid distribution system. All stakeholders will require significant amounts of information and tools with which to act upon.

With this increased information flow, the users of the system can make quicker, more informed decisions about the system's use and how to optimize it. This information flow occurs through the increased use of intelligent digital devices and communications capabilities arranged to gather, transmit, decode, and analyze raw data into useful information and actions. The actions will become increasingly automated as technology advances.

Impediments for both utilities and customers to moving ahead with transformation to a smarter electrical delivery system include:

- Inertia of moving to a new way of operating and billing
- Fear of technical obsolescence
- Skepticism regarding benefits as compared to cost

To further complicate the situation, the Smart Grid is different for each utility. After all, each utility's customers have unique preferences which are shaped by their individual interest, their past experience with electrical utilities, and their historical cost of electricity. Each utility is also subject to unique legislative, cost, geographical, and technical constraints that influence its ideal Smart Grid solution.

The utility embracing the advancement of their Smart Grid will realize that new technology will continue to be developed as the system matures. Using open architectures, industry standard communications, and flexible process implementation can allow the Smart Grid system to grow with new advances. Not moving ahead with migration and adaptation toward impending technology prevents the benefits from accruing and the utility from learning how best to leverage the information obtained.

Utilities are also realizing that they tend to operate with data that could be greatly improved if it was more detailed about customer usage and system conditions. This data could also be better shared between divisions such as rates, forecasting, planning, generation operations, etc. The Smart Grid concept builds the bridge between the utility divisions through better data management capabilities. This improved data management provides more detailed information about the status and operation of all parts of the electrical grid to the entire enterprise for use in its decision making. This use leads to improved hour-to-hour operations, short and long term investments, resource planning, forecasting, financial planning, customer service, and a host of other areas.

1.2 RPU SMART GRID VISION

RPU has been developing increased utilization of digital data and automatic control across its electrical system. These enhancements are elements of the Smart Grid concept promoted by the federal government in the 2007 Energy Independence and Security Act. Burns & McDonnell assisted RPU in reviewing the anticipated benefits that can be obtained from use of increased digital data and control systems. The benefits can be categorized in the following areas:

- RPU Customers
  - Improved reliability and reduced service outage duration
  - Outage and power quality monitoring for each customer
  - Empowerment to reduce energy usage and energy costs
  - Improved customer service and more energy choices
  - Increased detail of energy usage information
  - Better understanding of the cost drivers associated with generating electricity
  - Tools to better evaluate energy efficiency investments or adjust energy usage
- Rochester Community
  - Reduced regional GHG emissions
  - Increase in local technical jobs
  - Improved local business climate and energy support for new businesses
  - Improved resources for residential and corporate citizens
- RPU Operations & Efficiency
  - Improved voltage management and conservation
  - More efficient and effective dispatch of field crews
  - Better and more up-to-date data availability across the enterprise
  - Increased efficiency of personnel and the electricity delivery system
  - Reduced Maintenance expenses

The discussion of these benefits led to the development of the RPU Smart Grid vision statement:

> *"RPU will prudently adopt Smart Grid technologies which provide customer value in reliability or service."*

The improvement of efficiency and performance in all sectors (end customer, distribution, and generation) and environmental impacts are the main goal of this Smart Grid vision.

The development of this Smart Grid business plan for RPU has incorporated the following activities:

- Benefit identification workshop with over 20 RPU management and staff
- Development of an organizational Smart Grid vision
- Identification of measurable objectives to be met along the path to the RPU Smart Grid vision
- Analysis of what components of the existing RPU system could be leveraged for use in the Smart Grid and what new components are needed (gap analysis)
- Estimate of the costs and benefits associated with various Smart Grid implementation approaches

The digital devices and communications capabilities necessary to support the vision developed by RPU include additions or upgrades in the following major areas of the RPU distribution system:

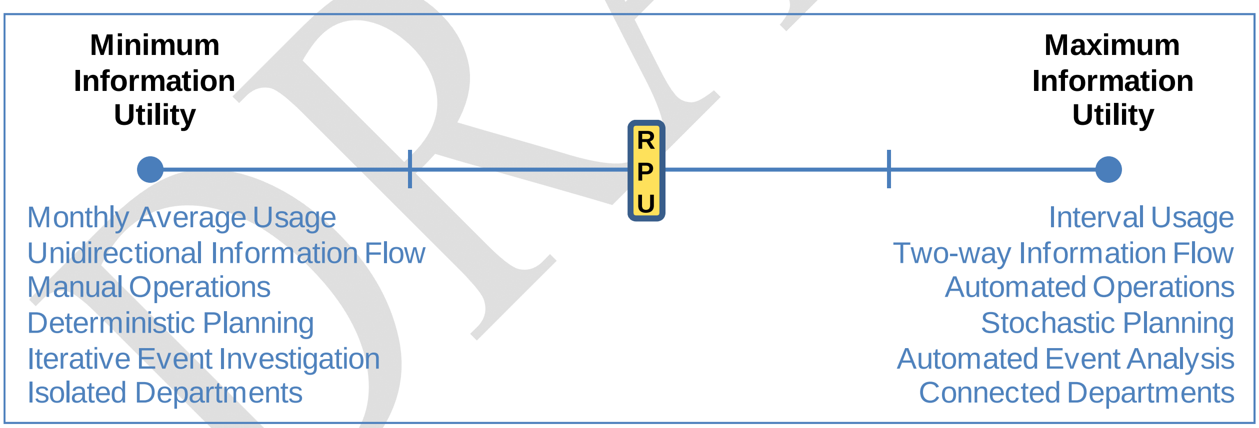
- Engaging and empowering customers to manage their energy usage
- Enhancing the way RPU meters customer usage and charges consumers for that use
- Improving and automating the RPU distribution system, increasing reliability
- Expanding RPU’s enterprise data management systems for increased data storage and sharing
- Implementing an RPU communication system as required to facilitate data flow in real-time

In all areas, the necessary system security from internal or external intrusion or misuse will be provided. The following sections provide the specific elements to be developed by RPU in the above areas.

1.3 RPU LEVEL OF SMART GRID FUNCTIONALITY

A utility’s transformational progress toward Smart Grid functionality may be viewed as a spectrum based on control and information capabilities. Figure 1-1 demonstrates the full spectrum ranging from a utility with minimal control and information gathering and utilization to a Smart Grid functioning utility with prolific control and information gathering capabilities and utilization.

Figure 1-1: Information Sharing-Based Smart Grid Spectrum



RPU has made extensive investments in upgrading it systems and operations to improve information gathering and sharing with its customers. For example, RPU has deployed an automated meter reading (AMR) system that improves monthly meter reading efficiency and reduces operating costs. Additionally, RPU has implemented OPOWER, a Smart Grid software program that informs customers of how their energy usage compares to similar homes. Customized analysis is executed each month for each customer by the OPOWER software and results are relayed to each customer through direct mailing. This information is educating the RPU customers on their electricity usage and has been known to successfully motivate customers to conserve and shift load to non-peak periods through a customer engagement approach.

No known utility has achieved maximum information gathering and utilization to date and relative to its peers; RPU owns and operates an advanced electric utility system. Table 1-1 summarizes RPU's Smart Grid capabilities within various categories.

Table 1-1: RPU Smart Grid Scorecard

CATEGORY	UTILITY WITH **MINIMAL** SMART GRID CAPABILITIES	**RPU** SMART GRID CAPABILITIES	CONVENTIAL WISDOM OF A UTILITY WITH **FULL** SMART GRID CAPABILITIES
CUSTOMER SERVICE	-MANUAL CONNECT & DISCONNECT -MANUAL POWER QUALITY REVIEW -OUTAGE REPORTS BY CUSTOMER CALL IN	-REMOTE CONNECT & DISCONNECT -MANUAL POWER QUALITY REVIEW -OUTAGE REPORTS BY CALL IN	-REMOTE CONNECT & DISCONNECT -REMOTE AND CONTINUOUS POWER QUALITY REVIEW -AUTOMATED OUTAGE DETECTION AT EACH METER
RANK:	*0*	*30*	*100*
CUSTOMER INFORMATION & CONTROLS	-MEASURE & REPORT AVERAGE MONTHLY USAGE -BILL ENERGY BASED ON AVERAGE MONTHLY COSTS -PROVIDE CUSTOMERS WITH MONTHLY STATUS/BILL	-OPOWER CUSTOMER USAGE COMPARISON REPORTS -AVAILABLE VOLUNTARY TOU RATE STRUCTURE	-MEASURE & REPORT HOURLY USAGE -DYNAMIC HOURLY PRICING -REAL-TIME AVAILABILITY OF HOURLY STATUS -TWO-WAY COMM. W/ HOME AREA NETWORK
RANK:	*0*	*40*	*100*
LOAD UTILIZATION	-NONE	-DIRECT LOAD CONTROL PROGRAMS -DEMAND RESPONSE PROGRAMS	-DEMAND RESPONSE MARKET BIDS -UTILITY & CUSTOMER CONTROLS -ANCILLARY SERVICES
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DISTRIBUTION AUTOMATION	-MANUAL SWITCHING -NON-PARALLELED DISTRIBUTED GENERATION -SYSTEM MONITORING & REMOTE CONTROL AT SUBSTATIONS	-AUTOMATED CAPACITOR BANK SWITCHING -SCADA SYSTEM CONNECTING ALL SUBSTATIONS -INTELLIGENT RELAYING	-AUTOMATED SWITCHING -MICROGRIDS -LOAD MONITORING ALONG FEEDERS -LOAD MONITORING AT DISTRIBUTION TRANSFORMERS -MONITORING & CONTROL AT EACH ASSET/DEVICE -AUTOMATED OUTAGE ISOLATION
RANK:	*0*	*60*	*100*
ASSET MANAGEMENT	-ASSET MANAGEMENT AT SUBSTATION LEVEL -NO SCADA -DETERMINISTIC PLANNING -STATIC ASSET RATINGS	-SCADA SYSTEM CONNECTING ALL SUBSTATIONS	-MONITORING OF DISTRIBUTION-LEVEL TRANSFORMERS -AUTOMATED ADVANCED ANALYSIS OF SCADA DATA -STOCHASTIC PLANNING -DYNAMIC ASSET RATINGS
RANK:	*0*	*60*	*100*
RELIABILITY	-REACTIVE CORRECTIVE ACTION -EVENT REPORTS BY CUSTOMER CALL IN -GENERAL IDEA OF EVENT LOCATION -MANUAL RESPONSE PLANNING & EXECUTION -MANUAL SYSTEM RECONFIGURATION -ELECTRO-MECHANICAL RELAYS	-OUTAGE MANAGEMENT SYSTEM -COMPUTER RELAYS	-PREDICTIVE CORRECTIVE ACTION & EVENT AVOIDANCE -AUTOMATED OUTAGE DETECTION AT EACH METER -SPECIFIC & AUTOMATED LOCATION/CAUSE REPORTING -AUTOMATED OUTAGE ISOLATION -AUTOMATED CUSTOMER INFORMATION REPORTING -COMPUTER RELAYS
RANK:	*0*	*50*	*100*
ENTERPRISE	-MANUAL MONTHLY METER READING -AVERAGE MONTHLY USAGE INFORMATON -DETERMINISTIC ASSET MANAGEMENT -ISOLATED & LIMITED INFORMATION SHARING ACROSS DEPARTMENTS	-DRIVE-BY AUTOMATED METER READING	-REAL-TIME HOURLY USAGE -DYNAMIC TREND ANALYSIS FOR ASSET MANAGEMENT AND PREDICTIVE NOTIFICATIONS -REAL-TIME INFORMATION AVAILABLE ACROSS ALL DEPARTMENTS -REMOTE & AUTOMATIC METER READING
RANK:	*0*	*25*	*100*

* * * * *

SECTION 2

SMART GRID OBJECTIVES

2.0 SMART GRID TECHNOLOGIES & OBJECTIVES

2.1 CUSTOMER

2.1.1 The Smart Customer

A significant portion of Smart Grid equipment and technologies are intended to enable customer choice and control over their energy usage. This includes offering or at least supporting the implementation of tools that enable customers to manage their energy consumption and incentives that encourage responsible energy management. A successful Smart Grid will rely heavily on customer participation to achieve increased grid efficiency and utilization.

Smart customers will:

- Have access to and regularly evaluate their energy usage profiles
- Adjust their energy usage patterns to minimize their costs
- Invest in energy efficient appliances
- Participate in demand response programs such as TOU, CPP and/or real-time rate structures
- Participate in direct load control programs such as central air conditioning compressor cycling
- Advocate energy conservation
- Use two-way communications to share more information between the customer and RPU

There are means for customers to accomplish many of these behaviors on their own; however, direct load control programs and billing communications require utility involvement. For example, a customer may purchase and have an electrician install an energy meter and compatible home energy display (HED) device and successfully monitor their energy usage in real-time. They may use this information to alter their energy consumption to shift load from peak to off-peak periods or simply to conserve energy. Under current conditions, conservation may result in reduced energy costs but behaviors such as load shifting and participation in demand response programs must be rewarded by the utility. In addition, without utility coordination, education, and incentives, it has been demonstrated that only an extreme few will be willing to take the steps necessary to manage their energy consumption at a sophisticated level.

2.1.2 RPU's Smart Customer Objectives

In addition to maintaining a high level of service and reliability to its customers, RPU will begin to offer its customers improved information and choice regarding their energy consumption. RPU believes customers should have access to their detailed usage information. This can be accomplished in numerous ways and RPU will facilitate alternatives depending on customer preference for cost and intended actions based on the information they receive. In conjunction with detailed usage information, RPU will likely develop TOU and/or CPP rate structures that could be implemented either on a mandatory or voluntary basis.

TOU and CPP rate structures better align retail energy costs to the variable costs to generate electricity. Under a mandatory implementation, all RPU customers would receive an advanced meter and be billed according to new rate structures. Under a voluntary implementation, only those customers that choose to participate would be billed according to new rate structures. New rate structures would be designed to reward customers for successfully shifting energy usage to off peak periods. The decision to implement TOU and/or CPP rate structures mandatorily or voluntarily will depend on the preference of the Rochester community and the expected benefits associated with each approach.

RPU will also likely develop new demand response programs, such as direct load control, and enhance current programs to facilitate customer involvement and control in improving the efficiency and reliability of the local grid.

It is important to note that RPU's objectives are to provide energy information and choice only to those customers who want it, not impose these services and associated costs to those who do not.

2.2 METERING

2.2.1 Smart Metering

A fully functioning Smart Grid will rely heavily on advanced monitoring and measuring of customer usage at their meter in addition to remote service control. Customer usage information may be coupled with cost and utilized by customers to make informed energy use decisions. Real-time usage information and remote control can be utilized by the utility to improve operational efficiency and offer energy choice to customers.

Advanced functionality from the use of advanced meters includes:

- More precise consumption data in intervals down to one hour or less
- Remote reading at determined intervals as well as on-demand
- Remote connect and disconnect of service to customers
- Power quality monitoring at the customer meter that provides automatic outage notification
- Enable TOU, or other time varying rate structures, to align retail rates with the costs to generate or purchase power from wholesale markets

All of the advanced features listed above may be achieved through the implementation of a complete advanced metering infrastructure (AMI) solution that includes new solid state meters at each customer location and a high bandwidth, two-way communication system that transmits information between the meters and the RPU service center. An AMI solution can provide numerous benefits to the capability and precision of utility operations but it represents a significant investment for the utility.

While an AMI solution will accomplish all the above described functionality, ultimately, there are numerous ways for a utility to achieve each advanced feature regarding customer usage monitoring and measuring and service control. For example, a modern advance meter reading (AMR) system can provide precise consumption data at short read intervals; cellular or radio communication units on customer meters can enable remote interval and on-demand readings; communications from the RPU service center may be delivered to the customer via the internet; etc.

2.2.2 RPU's Smart Metering Objectives

RPU would like to achieve increased information regarding customer usage information. This information will help RPU better understand their system load profile as well as usage habits of various customer demographics. RPU would also provide this usage information to RPU customers so that they may utilize it to make informed energy usage decisions.

2.3 TRANSMISSION AND DISTRIBUTION SYSTEM

2.3.1 Smart Transmission and Distribution System

Another integral component to a Smart Grid is an advanced transmission and distribution system that enables automation and increased monitoring of the transmission and distribution system assets. Smart Grid advanced features associated with transmission and distribution include:

- Remote monitoring of assets such as transformers, capacitor banks, switches, etc.
- Remote control and/or switching of assets
- Automated control and/or switching of assets
- Data collection of events at assets
- Accommodate integration of customer-owned distributed generation systems
- Optimization of voltage on all circuits within the distribution system
- Increased utilization of system assets to maximize capital investments

In general, the above features can be addressed by replacing transmission and distribution monitoring and control equipment with newer advanced digital or computerized equipment. Also, it is necessary to provide the means with which to monitor and communicate with these devices from the RPU service center.

Most utilities, including RPU, currently operate a sophisticated supervisory control and data acquisition (SCADA) system that communicates between the utility's service center and all, or at least most, of that utility's substations.

2.3.2 RPU's Smart Transmission and Distribution System Objectives

RPU strives to improve distribution efficiency and performance measured by reliability and cost of service. RPU would like to achieve automation and system monitoring capabilities that demonstrate improvements to both distribution efficiency and reliability. This may include real-time data monitoring and automated and remote controlled switching capabilities.

2.4 ENTERPRISE DATA MANAGEMENT SYSTEM

2.4.1 Smart Data Management

Interval metering and advanced transmission and distribution asset monitoring will produce more data than utilities currently collect, manage, store and use. A Smart Grid requires that all relevant data be readily available to all departments of the utility as well as usage data available to customers. Full utilization of this data will require an advanced enterprise data management system that will enable the following features:

- Real-time awareness of system and subsystem loads
- Sharing of load and event information across departments
- Generation control and optimization
- Customer access to their account and detailed usage information
- Customer analysis and trending of their detailed usage information

Collecting more detailed data about customer energy use will improve RPU's awareness of system and subsystem loads and allow it to tailor rate programs to specific demographics. Thorough analysis of collected data will enable more efficient and effective advance generation and/or wholesale purchase planning as system loads are understood with greater precision. Comprehensive data repositories will be needed to allow all departments to access and utilize this information within their operations. Additionally, existing database systems often must be upgraded or replaced in order to integrate with the new data repositories.

As the electrical demand increases along with the costs to meet those demands, it is becoming more important that utilities better align their retail rates with their costs to generate or procure energy for their customers. This will help shift peak energy usage and make the national electrical system as well as each utility's generation and transmission assets more efficient.

The Smart Grid also requires that customers become more involved in managing their energy consumption to achieve peak shifting and energy conservation. In order to accomplish this, customers must be educated on the generation of their electricity and must have access to their detailed usage information so that they may use it to make informed decisions regarding when to use energy and whether to invest in energy management and conservation capabilities. Enhancing the customer's awareness can be accomplished through a variety of options including utilization of the internet or in home energy display technologies.

RPU should have detailed plans for how the data will be collected, managed, and used. As with all data collection and analysis; RPU should plan for validating, estimating, and editing (VEE) the collected data. Due to the level of collaboration between the utility and the customer and the customer's active involvement in energy management that an effective Smart Grid requires, data will have to be collected, validated, and analyzed in a timely fashion. The development of the data management and communications systems will need to take into consideration the granularity and speed at which data is needed by the various users.

For instance, use of the data in generation control can require data to be collected and processed in less than 10 minute intervals. This will provide challenges for current metering and communication systems. Time for extracting data from repositories, looking for gaps, and ensuring the proper fields are present for the data analysis tools must be considered. This is for a data set that does not have any problems and has already been processed through a VEE module. Problematic meter data can increase data processing time due to VEE delays.

2.4.2 RPU's Data Management Objectives

RPU will pursue data management capabilities and systems as required based on customer demand for and participation in time-varying rate structures and detailed energy usage data access as well as future distribution monitoring data storage and management requirements.

2.5 COMMUNICATION SYSTEM

Nearly all Smart Grid features described in the preceding sections depend on a robust, scalable, two-way communication infrastructure. In the past, utilities typically owned their own communication system with the exception of the telephone system. Most communication systems that utilities are currently utilizing are aged and not designed to carry the high volumes of digital data that Smart Grid technology may require. The bandwidth for these systems must support the data transfer required by the amount and frequency of collection for the data and controls anticipated, so upgrades may be required.

Remote meter reading, SCADA, distribution automation, remote monitoring of critical infrastructure, demand response/demand-side management are examples of Smart Grid features that require a robust, high bandwidth, two-way communication infrastructure. This can be accomplished through the development of a proprietary and utility-owned Wide Area Network (WAN) or by securing/leasing bandwidth on existing third party communications systems such as cellular or radio networks.

A Smart Grid WAN generally has two major elements. The first is a high bandwidth backbone network for transporting mission critical network traffic and for backhauling non-mission critical data traffic. Second is a lower bandwidth distribution network, often referred to as the "last mile," for connecting customer meters and other smart devices to the backbone.

Typically, the backbone network needs to be robust and reliable with high bandwidth availability to support Smart Grid applications. This is most commonly accomplished through a fiber optic network that connects the utility service center to all or at least most substations throughout the service territory. The "last mile" may utilize one or more of a variety of capable technologies and/or already existing networks. The selection and design of the "last mile" system(s) will depend on geography, application and cost.

Many technologies may provide communications capabilities from the service center to distribution assets and customer meters. The characteristics of the system, the backbone and "last mile", will depend on the specific needs and objectives of the utility as well as geographical, technological, and cost constraints.

2.6 SECURITY AND COMPLIANCE

Smart Grid technologies will create numerous additional communications methods and important data. This data may consist of utility operational data and customer usage information. Both types, if left unprotected, can result in reliability and privacy risks and exposures for the utility investing in AMI or other Smart Grid implementations.

NERC, the electric reliability operator appointed by FERC, has enforced numerous regulatory standards for the proper control and management of electric generation, transmission, and distribution. Most of the security standards are based on the idea of identifying critical assets. These security standards have left out Smart Grid networks because these technologies are using distribution infrastructure. As organizations implement AMI and other applications that require data collection and management, they must be sure to address developing operational standards to ensure the safekeeping of the data, and the integrity of electric operations.

There are no specific Smart Grid regulations in place that dictate security of Smart Grid-related applications, systems, and networks. However, it is also important to note that the implications of the NERC reliability standards do not specifically rule out applying the requirements to Smart Grid-related activities. Therefore, it is recommended that RPU consider applying the principles of industry standards to utility Smart Grid deployments. NERC CIP-002-009 and NIST 800-53 are examples of these standards.

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SECTION 3

RPU SMART GRID GAP ANALYSIS

3.0 RPU SMART GRID GAP ANALYSIS

3.1 RPU EXISTING SYSTEM

3.1.1 Customer

RPU has a relatively aware customer base that participates in conservation and load management programs offered by RPU. These programs include:

- The RPU PARTNERS direct load management program (CAC & Electric Water Heaters)
  - RPU rewards participants with monthly credits to their bill
  - 8,000 participants that represent approximately 11 MW of controllable load
- Conserve & Save program (Electric)
  - CFL rebates
  - Energy Star Appliance rebates
  - LED rebates
  - Air-source Heat Pump rebates and rates
  - Geothermal Heat Pump rebates and rates
- General Service TOU rates available (seasonal)
  - 18 participants
- Net metering program (up to 40 kilowatts, same as state limit) for distributed generation
  - kilowatt-hours provided to grid are credited at a lower rate than kilowatt-hours used
- OPOWER – customer usage comparison reports provided to participating customers
- Conserve & Save program (Water)
- Subsidized energy audits through RPU
- Kill-A-Watt™ Meter program
- Minnesota Residential Energy Incentives, Rebates, Programs
- Service Assured℠ – coverage for repairs to electric or water services

Customers are also educated about energy and water services by RPU primarily through the RPU website, customer service inquiries, and bill stuffers.

3.1.2 Metering

RPU has a system of approximately 48,000 electric customer meters and 37,000 water customer meters. Over the last 10 years, RPU has completely overhauled these customer billing unit meters. All electric and water meters are now capable of transmitting usage information over the air a relatively short distance, up to half a mile. This system is commonly referred to as a drive-by automated meter reading (AMR) system. Some of RPU's General Service electric meters read and transmit demand information, kilowatts, in addition to usage information but all residential and a majority of General Service electric meters transmit usage information only. More advanced meters at large commercial and industrial customer locations can measure demand (kilowatts) and reactive power (kVAR) information.

RPU's residential and General Service electric meters include a mix of electromechanical and solid state technologies. A breakdown of this mix for each customer class is detailed in Table 3-1. All of RPU's Electric and Water meters include an Encoder-Receiver-Transmitter (ERT) device manufactured by Itron. The ERT transmits the meter's current usage measurement through the air via radio frequency technology up to a range of half a mile. Electromechanical meters contain mechanical gearing that measures wattage consumption and display it through a series of dials. Dial readings are read by an optical device and transmitted through the meter's ERT. Solid state meters include both current and voltage probes that measure and converts readings into wattage consumption information which is transmitted through the meter's communication module. There are 18 General Service TOU meters that measure energy separately for two programmed daily time periods. They are read manually on a monthly basis and simply provide a demand and usage reading for each time period.

Table 3-1: RPU Electric Meter Endpoints

Customer Class	Solid State	Electromechanical	TOTAL
Residential	15,100	28,023	**43,123**
Small General Service	2,356	1,832	**4,188**
Medium General Service	436	0	**436**
Large General Service	18	0	**18**
TOTAL	**17,910**	**29,855**	**47,765**

All meters are read once a month by RPU field personnel with the use of a mobile collection system also manufactured by Itron. This system consists of a receiver and data storage unit that are mounted into dedicated RPU vehicles. The vehicles then drive routes within the vicinity of each meter and collect usage information that is being transmitted by the ERTs within each meter. RPU employs three meter reading personnel and vehicles that operate daily to capture at least one reading from all customers each month. Readings of all residential and most general service meters consist of a single monthly total for the energy consumed (kilowatt-hour) for the month. Some larger commercial and industrial meters measure and transmit monthly energy as well as peak demand (kilowatts) and reactive power (kVAR) that factor into billing for these accounts.

RPU currently accommodates just a few net meters serving customers with small wind or solar distributed generation systems. Net meters measure energy into the meter as well as energy out of the meter back onto the RPU distribution system. If a customer-owned generation system is expected to contribute energy back to the RPU distribution system, metering may include two meters; one which measures energy to the customer and one that measures energy from the customer. If a customer-owned generation system contributes energy to the grid, they are currently compensated for that energy at a special rate that is determined based on the standard retail revenues excluding fixed revenues associated with the customer charge. Alternatively, if a customer-owned generation system is not expected to contribute energy to the RPU distribution system but rather merely offset consumption, then that customer may retain standard metering, simply consuming less energy from RPU.

3.1.3 Transmission and Distribution System

RPU currently has a supervisory control and data acquisition (SCADA) master station installed at its operations center and also a secondary station at the Silver Creek generating station. The SCADA system is connected to remote terminal units (RTU) at all of RPU's substations. The data polled by the SCADA master includes alarms, status, and power system values (volts, amps, power, etc) and provides remote control of breaker and certain motor operated switches.

RPU has 16 transmission capacitor banks that could be VAR controlled today (eight of those are still on fixed VAR settings). About 24 transmission capacitor banks have controllers installed that could receive external signals without major modification. On the distribution system, RPU has 85 distribution capacitor banks of which 44 have some kind of "working" controller. The remaining 41 are fixed but some of those fixed capacitor banks do have working switches on them. At this point in time, none of the installed transmission or distribution capacitor banks are remotely controlled.

Under existing RPU upgrade plans, transmission protection relays will be 100 percent capable of fault location by the end of 2010. Distribution relays will be 75 percent capable of fault location by the end of 2010 and 100 percent capable of fault location by the end of 2011.

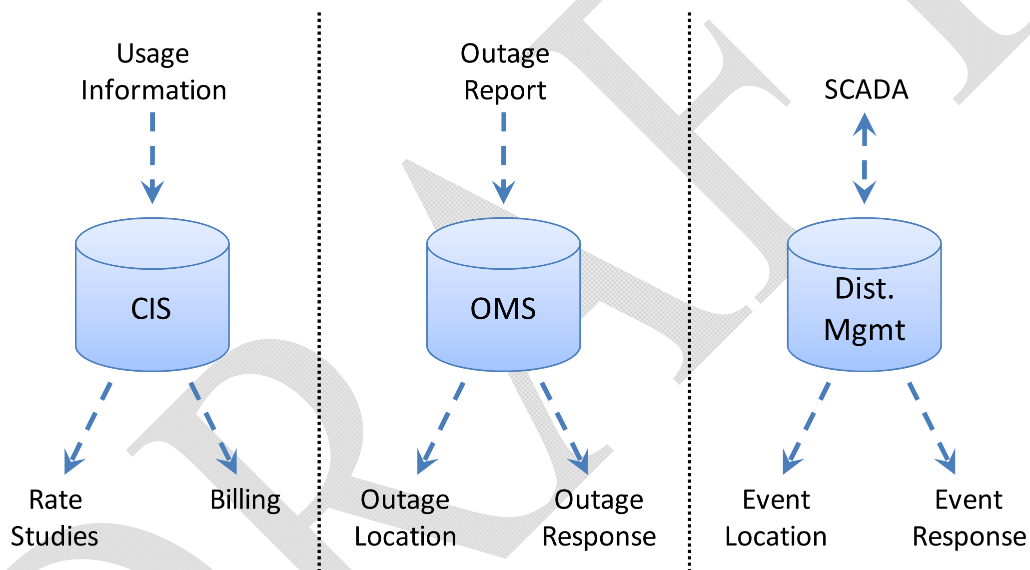
There are approximately 268 switches on the RPU transmission and distribution systems ranging from 600 to 900 amps. All are on 3 phase circuits and accomplish either disconnects or load breaks.

Switching activities on the RPU distribution system are scheduled and directed by "RPU 7," an RPU procedural document. Maintenance and testing of substation equipment is conducted in compliance with NERC Standards PRC-005 and PRC-008 through a well documented, comprehensive maintenance and testing program.

3.1.4 Enterprise Data Management

Currently, monthly meter usage information is collected by the RPU drive-by AMR system and is processed by RPU's Itron MV-RS software. MV-RS then generates a file containing all current month meter usage information that is transferred, compiled and stored into RPU's SAP customer information and billing system (CIS) which runs SAP's ICU/CCS software. The system is often referred to as the CCS. This current CCS went live at RPU in December of 2007. The CCS at RPU is primarily used for billing and managing customer account data. Currently, the CCS is not configured to interface with the outage management system (OMS) or SCADA system. Each system is operated and utilized independently, as depicted in Figure 3-1.

Figure 3-1: Current CIS & Other Enterprise Systems



Average monthly usage information provides few specifics about the individual usage patterns of RPU's residential and commercial customers. Use of average consumption information is acceptable from a billing perspective when energy charges are limited to a typical average charge per kilowatt-hour rate structure as is currently applied to most customers of RPU. Under this type of rate structure, the time of day in which usage occurs does not impact a customer's bill, since kilowatt-hours cost the same throughout the day and month.

In parallel to the CCS, RPU currently operates an OMS system that includes Telvent's Responder Program version 9.3 in conjunction with ESRI's ArcGIS version 9.3.1. Databases are SQL 2005. This system does utilize a geometric network for tracing and predicting outage events but the system does not currently include any communication or data links to the SCADA or interactive voice response (IVR) systems, although such connections are possible with the Telvent Responder Program.

RPU is in the process of developing a data warehouse that will manage and store data generated by RPU's SCADA system and generation controls systems. This data warehouse will be located at the Silver Creek generating station and it will be capable of handling all of RPUs current data management and storage requirements.

3.1.5 Communications Systems

RPU utilizes a wholly- and jointly-owned fiber-optic network that currently connects 40 percent (four out of ten) of its substations to each other and to the RPU service center. Currently, wholly-owned fiber lines consist of overhead power ground wire (OPGW) that includes 24 fibers. Traffic on the RPU OPGW fiber lines consists mainly of RPU data communications, such as SCADA and transmission relay control. Jointly-owned fiber lines are both above and below ground installations with more fibers, thus higher bandwidth capability. A detailed layout of the RPU wholly-owned and jointly-owned fiber networks is shown in Appendix A. These lines will be co-owned with the City of Rochester and connect to city infrastructure and emergency service provider systems. Data traffic on the jointly-owned fiber lines includes RPU data communications as well as internet, voice, video and city data transmission. This fiber-optic network is in the process of being expanded to the remaining substations and the RPU operations center. For those substations that are not connected by fiber, communication between RTUs and the RPU SCADA system is accomplished through leased telephone lines as is transmission relay control.

In 2006, RPU conducted a technology pilot that installed fixed network AMR meter data collection equipment throughout three targeted northern residential neighborhoods of Rochester. This system consisted of a single data collector, cell control unit (CCU), and 12 repeater units that extend the reach of the CCU. The system managed to read as many as 1500 meter endpoints in and around the targeted neighborhoods; however some of the endpoints at the periphery of the system's range were not consistently read each month. Collected data was backhauled to a remote server hosted by Itron for storage over cellular transmission service provided by Cingular (now AT&T Wireless). All fixed network equipment was provided by Itron and operated seamlessly with the existing Itron ERT modules installed at RPU meter endpoints. Collected usage data was hosted on remote servers managed by Itron and was accessible by RPU personnel via remote login. The system operated successfully for approximately five months before funding for the program was discontinued. The fixed network equipment remains installed but the current condition of the CCU and repeaters are unknown.

RPU also utilizes a power line carrier (PLC) communications system to communicate with direct load control devices installed on the distributions system. Load control devices enable RPU to shut off customer loads such as electric hot water heaters, central air conditioners, electric heaters, and motors during peak demand periods. This system is aged, troublesome to maintain, and incapable of significant expansion.

Most RPU customers currently have internet access or are capable of connecting their home or business to the internet. Internet service in Rochester is available through local cable and DSL providers, Charter and Qwest.

The RPU region also has access to a privately-owned Arcadian 700 MHz network that could be utilized for additional communication traffic but it is not currently used by RPU. Currently, this system only covers a portion of the RPU service territory so it could not provide system-wide communications without expansion.

3.2 RPU UPGRADE CONSIDERATIONS

3.2.1 Customer

Since RPU's system reliability has a history of exceptional performance, RPU should focus near-term investments on expanding the services offered to customers and improving operational efficiency. Customer preferences and expected participation should drive RPU's decisions regarding investments in new technologies and services.

Three customer-related services should be explored by RPU. Each can be achieved through various technologies and strategies. First, RPU could help customers gain access to detailed energy usage profiles of their homes and businesses. Access to more detailed information will enable customers to manage their energy usage and could be accomplished through numerous methods, including:

- RPU could refer customers to an electrician for the installation of a home energy device (HED) entirely on the customer side of the meter
- RPU could install a smart meter and a ZigBee connected HED
- RPU could install a smart meter; city-wide fixed communications network and manage meter data including providing the usage data back to customers via the web or bills

Second, RPU could implement residential TOU and/or CPP rate structures on a mandatory or voluntary basis, providing customers more choices. Interval metering required for TOU/CPP rate structures could be accomplished through:

- RPU could install smart meters, capable of storing interval usage data locally, for participating customers only and read these meters once a month through existing means
- RPU could install smart meters for participating customers only in conjunction with a fixed communications network AMR
- RPU could install smart meters to all customer (Full AMI solution) and fixed communications network AMR

Finally, RPU could expand their PARTNERS direct load control program to more technologies, customers, and appliances:

- RPU could install a fixed communications network capable of communicating with meters and compatible load control switch devices, replacing the RPU PLC communication system

3.2.2 Metering

One of RPU's primary objectives is to provide its customers access to more information about usage. It would also be operationally beneficial for RPU to obtain more detailed information about the system and subsystem loads. Energy usage measurements at the customer location are desired in intervals of one hour or less in order to develop individual load profiles that will be useful to the customer and to RPU. In order to achieve this level of metering interval, RPU may:

- Facilitate HED device installation on the customer side of the meter
- Install a smart meter in conjunction with a HED (without fixed communication network)
- Install a smart meter in conjunction with a fixed communication network and MDMS
- Procure a complete AMI solution with all new smart meters and a fixed communication network

The option of facilitating the installation of devices on the customer side of the meter would provide the customer with interval usage data but not RPU.

A smart meter in conjunction with a HED connected through a ZigBee connection would provide the customer with access to real-time and historical interval usage data. It could also provide RPU with interval usage data since this data could be stored at the meter and acquired at RPU's convenience or through regular meter reading activities, without the use of a fixed network. This option would not enable features such as on-demand reads, outage notification, or remote connect/disconnect, however, a fixed two-way network could be added later to enable these features. RPU could offer this service on a volunteer and cost-sharing strategy depending on the cost tolerance of early adopters.

Procuring and installing select smart meters along with a city-wide fixed network communication system that can interface with the existing Itron ERT modules would enable all advanced features of deployed smart meters as well as improve metering capabilities with existing meters. RPU would be able to read all meters on-demand and achieve some level of outage notification/location depending on how often meters are queried. It would only enable two-way communications or remote connect/disconnect between RPU and customers with capable smart meters. Due to the proprietary communications protocol of the Itron ERT modules, RPU is limited to acquiring Itron's fixed network equipment if compatibility with existing meters for AMR is desired. Table 3-2 summarizes approximate cost ranges for both of these options.

A complete AMI solution is the most expensive option in initial capital expense to facilitate interval meter reading. However, it will also enable additional advanced features which would provide ongoing benefits and efficiencies such as remote connect/disconnect at each endpoint, two-way communications between RPU and its customers, on-demand meter readings, outage notification/location, power quality information, and more. A full AMI solution may be provided by various reputable vendors but would utilize little of RPU's existing metering assets.

Table 3-2: RPU Metering Upgrade Costs

Option	Description	CapEx
Full AMI Solution	Replacement of all meters (unless compatible) with AMI solid state smart meters and also install associated high-bandwidth two-way communications network and meter data management system.	$15,000,000 – $20,000,000
System-wide Fixed Network AMR w/ Interval Reading Capabilities and web-based Energy Dashboard	Install a fixed communication network that is compatible with existing AMR endpoints and install smart meters at locations that require interval metering and install/lease meter data management system. Usage data could be delivered to customers via web-based energy dashboard or simply through monthly bills with OPOWER comparison.	$2,000,000 – $5,000,000

3.2.3 Transmission and Distributions System

RPU currently operates very reliable electric and water distribution systems. Electric reliability measures of the RPU system are consistently above average relative to its peers and customers seldom experience outage events due to system fault or failure. However, some measures could be taken to modernize, automate and enable remote control over RPU's electrical distribution system.

RPU could enhance distribution automation (DA) on their system beyond VAR controlled capacitor banks to include additional data collection, monitoring and remote control of switching on the distribution feeders. This will allow RPU to better operate and manage its distribution system and increase reliability. If coupled with the “by meter” power monitoring, more refined feeder switching could be used to isolate smaller portions of the distribution system during outages. Approximate costs of DA upgrade considerations are summarized in Table 3-3.

DA will also support the deployment of distributed generation on the distribution system. This generation, when coupled with increased feeder sectionalizing capabilities and advanced load control, can be used to optimize voltage and current on all circuits as well as potentially create “micro-grids” on the distribution feeders when adequate distributed generation capacity exists. Both of these capabilities will increase the number of customers who have power during a feeder outage.

The increased switching capabilities provided by DA can also be used to more rapidly transfer portions of the system to other feeders for outage and maintenance switching. This will also assist in reducing outage times and the crew time to perform these functions.

The process of installing DA equipment is well known and should not present any significant issues to RPU during its implementation. Communications with distribution equipment such as sensors and switches may be accomplished through a dedicated narrowband system or through a shared AMR fixed network communications system.

Table 3-3: RPU Transmission & Distribution Upgrade Costs

Option	Description	CapEx
Capacitor Bank Controllers	Installation of intelligent capacitor bank controllers on all of RPUs distribution and transmission capacitor banks plus the installation of new capacitor banks where needed.	$500,000-$1,000,000
Automated Switching Equipment	Installation of intelligent switching equipment strategically located along the RPU feeders for localized isolation of faults and greater distribution flexibility.	$3,000,000-$4,000,000

3.2.4 Enterprise Data Management

The implementation of interval meter data for RPU through any of the methods described in Section 3.2.2 will require a new meter data management system (MDM). The MDM will receive, manage and store usage information from meter readings and send price signal and other information out to smart meters.

Data received from the meters will be verified and corrected with additional reads if necessary. The MDM should interface with the CIS system if RPU is to bill according to the interval data, such as in the case of TOU and/or CPP rate structures. Ideally, the MDM should interface with other utility database systems such as outage management and distribution management to create a seamless dashboard of services and information that will be at the disposal of personnel responsible for customer service, operations, and other day-to-day functions within RPU.

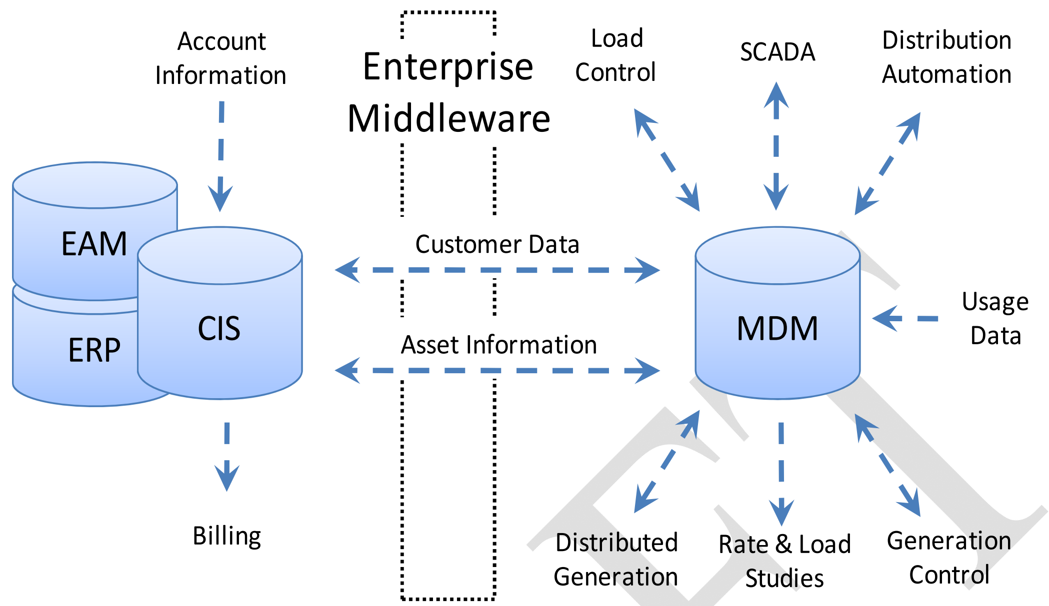
Because the energy use data that the MDM contains is central to an effective Smart Grid system, the MDM must be capable of handling voluminous interval meter data and communication requirements. In order to meet these demands, the MDM must include a data warehouse that can provide the kind of storage, analysis, and reporting tools needed. The MDM may be developed and operated internally to RPU or, alternatively, venders such as Itron offer remote MDM services. Under this scenario, interval meter data is sent to and stored at remote servers that are owned and operated by the vendor, such as Itron. RPU's CIS would then remotely access data on the remote MDM as well as receive regular reports.

As depicted in Figure 3-2, the MDM should also be interoperable with other database systems at RPU, such as the outage management and distribution management systems, and provide real-time access to current and historical energy usage data. This will eliminate data silos to improve efficiency and provide integrated analysis across most, if not all, of RPU's systems. The ability to analyze detailed usage and financial information simultaneously and in real-time will give RPU the opportunity to effectively manage distribution, load, and generation to lower delivery costs and maintain power quality.

RPU currently operates a modern OMS but should consider upgrading their distribution management system (DMS) with an equally capable and modern solution that is compatible with the current OMS. Modern solutions are available from the same vendor, Telvent, as well as multiple competitors that should provide equivalent functionality for a comparable price. However, there are advantages to expanding an existing vendor relationship and simplifying integration by using products from the same IT vendor.

Vendors will provide guidance for storage and computing power requirements of the MDM to support the new enterprise system. The number of customers, historical data requirements, and metering interval will determine the amount of storage space and processing power required. Because customers' meters are read and billed through the MDM and CIS, this will produce large volumes of data. Since real-time processing is inherently a slow process, it is important in the design of the system to allow for the high volume of real-time data requirements of the Smart Grid and the time intervals required by the RPU users.

Figure 3-2: A Smart Grid CIS and MDM Integration



RPU currently operates SAP's CCS, which is capable of being configured to interface with an MDM and bill according to interval usage data as well as interface with other RPU systems and databases. In addition to interfacing with RPU's meter reading system, CCS could also interface with other systems such as Mobile Asset Management, Global Information Systems (GIS), payment processing interfaces, and ISO website.

Although RPU's SAP CCS can accommodate interval meter data, other interface upgrades would be needed on the front end to enable advanced Smart Grid features that could fully utilize an AMI system. A modern system such as CRM has superior capacity to accommodate Smart Grid functionality as it was designed with that objective. If implemented at RPU, CRM would satisfy all Smart Grid objectives associated with customer billing and account management. Whether CRM or equivalent is implemented, the system should integrate all of the data modules for financials, materials management, and human resources. In addition to improving the functionality of the billing system, the upgraded CIS should also give RPU more data flexibility since data from the other systems will be integrated.

If a full AMI solution is implemented, the CIS must be upgraded and should be one of the first items implemented in order to link in the additional information from the new data sources. Additional time will also be required to configure the customer billing portion of the module with any new rate structures anticipated with the Smart Grid implementation. Anticipated costs for back office upgrades to consider are summarized in Table 3-4.

In addition to upgrades to software, hardware and storage, RPU will need to create new processes and a data management plan for handling the additional data and functionality. This plan should specify regular analytics of the data for utilization in utility business and operational practices as well as archiving of the data, on-site and off-site backup intervals, and how long the archives should be kept. The data management plan should also outline what to do in the case of a natural disaster or hardware failure.

Table 3-4: RPU Enterprise Data Management Upgrade Costs

Option	Description	CapEx
Update CIS	Upgrade SAP CCS to SAP CRM through Expansion Pack 5.	$440,000-$600,000
MDM	Meter data management software and hardware including software licensing, configuration, and system integration.	$500,000-$800,000
Telvent DMS/SCADA	Telvent distribution management system software licensing, configuration, and system integration.	$1,000,000-$1,100,000

3.2.5 Communications Systems

A communications system should be built only to support the smart grid objectives of RPU and its customers. To enable real-time or near real-time two-way communication between RPU and its customers, a high bandwidth wide area network (WAN) must be deployed or secured across RPU's service territory, likely in the form of a wireless fixed network similar to the Itron fixed network technology that RPU piloted recently. To enable real-time or near real-time two-way communication between RPU and distribution equipment such as sensors and switches, a dedicated narrowband RF network may be utilized or the high bandwidth fixed network may be utilized for both meter and distribution equipment communications.

A high bandwidth WAN will likely consist of a wireless fixed network consisting of distributed data aggregating receivers coupled with repeaters designed to cover the entire service territory. Each data aggregator will manage data traffic to and from meter endpoints through the repeater mesh and back to the RPU service center over a fiber, or alternate, backhaul system. Smart meter vendors such as Itron and Silver Spring Networks offer fixed network design, equipment, and installation services that are compatible with their respective smart meters and also meters from other vendors, in most cases. The ongoing and planned expansion of RPU's fiber-optic network could provide a reliable, high capacity, secured communication network that is capable of handling current and future backhaul traffic if a fixed network AMR/AMI is implemented.

In the event that a high bandwidth WAN is not implemented, or if critical DA equipment is not compatible with the high bandwidth WAN solution chosen, or if RPU wishes to segregate DA and metering communications, a dedicated narrowband (<400 MHz) communication system may be implemented to monitor and control distribution automation equipment such as sensors and switches. Since these devices require low bandwidth data traffic, a dedicated system may be implemented for reasonable costs and may likely be accomplished through the installation of one central antenna mounted high above the ground.

AMR/AMI solutions consisting of smart meters and a fixed communications network also have the ability to interface with home energy displays, home area networks (HAN), and building energy management systems (BEM). This feature will allow consumers to conditionally program their consumption during various pricing levels into their facility control system. The two-way communication system will be designed to allow the quantity of data to be transmitted efficiently by RPU.

HANs represent an opportunity for extension of smart metering intelligence into the home, potentially connecting the electric meter to electricity consuming devices and appliances. These devices may consist of entities such as smart thermostats, air conditioners, refrigerators, dishwashers, washer, and/or dryers. HAN wireless and wireline communications protocols, such as ZigBee and HomePlug, are becoming standardized to promote interoperability and expedite development. Energy conscious consumers are beginning to demand energy management solutions and utilities are responding by enabling real-time energy information that allows consumers to participate in home energy management programs both manually (price signals) and automatically (smart devices). HAN provide utilities with greater management efficiencies while allowing the homeowner to specify a mix of consumption and efficiency across a range of devices.

RPU may still deploy smart meters and implement time-varying rate structures without a fixed real-time communications infrastructure, however, customer usage data measured at those endpoints will not be available to RPU's operations center in real-time or on demand. As mentioned above, interval usage data may be downloaded through the drive-by AMR methods currently used.

Estimated costs of communications system considerations are summarized in Table 3-5.

Table 3-5: RPU Communications Upgrade Costs

Option	Description	CapEx
DA Narrowband Communications Network	Narrowband RF communications antennae installed at a central point in the RPU service territory capable of communicating to sensors and switches installed on the RPU distribution system. This includes purchase/lease of RF spectrum and installation of the central antenna.	$100,000-$150,000
WAN Wireless Fixed Communications Network	High bandwidth wireless fixed network covering the entire RPU service territory to facilitate two-way communications with meter endpoints (electric & water). This includes the design and installation of repeaters, data aggregators, and fiber upgrades for backhauling data to the RPU data center.	$1,000,000-$1,250,000

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SECTION 4

RPU SMART GRID PATHS FORWARD

4.0 RPU SMART GRID PATHS FORWARD

The decision with the most impact in the development of the smart grid for RPU will require the utility to consider its position on moving ratepayers to time varying rates such as TOU. In order to determine whether RPU should deploy smart grid technologies and advanced meters to all customers quickly depends on RPU's expectations regarding transitioning rate payers to time of use (TOU) rates. If RPU expects to transition all rate payers to TOU rates, then all customers would require new advanced meters within an advanced metering infrastructure (AMI). If RPU plans to offer TOU rates to customers on a voluntary basis, then RPU would only need to implement advanced metering to those customers who volunteer to participate and to those that provide strategic informational benefits.

A mandatory TOU approach requires advanced metering for all RPU customers; however, RPU may approach voluntary implementation of Smart Grid technology in a number of different strategies. RPU and Burns & McDonnell have identified and analyzed the following two strategic paths by which to implement Smart Grid technologies on the entire RPU system (refer to Appendix B for a graphical representation of these paths):

1. **Mandatory Rates / Mandatory Technology:** This approach assumes that all RPU customers are required to transition to TOU rate structures. Transition of all customers requires the installation of advanced metering to all RPU customers and supporting communications and data management all within a four year deployment period.

2. **Voluntary Rates / Mandatory Technology:** This approach assumes that TOU rates participation will be voluntary but that RPU will eventually deploy advanced metering, along with supporting communications and data management, to all RPU customers within a 15 year deployment period. Voluntary TOU participants will receive advanced meters in order to enable TOU interval billing. Other locations will receive advanced meters early in the deployment period based on strategic locations selected to provide power quality and outage notification information. Remaining customers will receive advanced meters through attrition, failure, and phased deployment throughout the 15 year deployment period.

Additional strategic paths have been identified by RPU and Burns & McDonnell that provide RPU customers with increased energy choice and access to Smart Grid technology but will not likely result in Smart Grid deployment across the entire system. For this analysis, these additional strategic paths were not evaluated in detail but should be considered viable paths forward for RPU:

A1. **Voluntary Rates / Voluntary Technology:** This approach assumes that TOU rates participation will be voluntary and that RPU would provide and deploy advanced metering to only those customers who participate.

A2. **Cost Share Advanced Metering:** This approach would provide advanced metering and compatible home energy displays to those customers who agree to pay a portion of the cost of the equipment and installation. By enabling customer access to real-time usage information through an advanced meter, both RPU and the customer may benefit from the usage data.

A3. **Customer Pays Advanced Metering:** This approach would provide advanced metering and compatible home energy displays to those customers who agree to pay the complete cost of the equipment and installation. RPU and the customer may benefit from the usage data collected.

A4. **Customer Access to Usage Information:** This approach is the least costly means of providing customers access to their usage information. It assumes no advanced metering is utilized but rather RPU will promote and facilitate customer adoption of devices that are capable of interfacing with their existing electricity meter to display near real-time home energy usage information. Capable devices are already on the market, such as the Cisco home energy controller, that can read the wireless information transmitted by the meter's ERT module. These devices will also be compatible with advanced meters should they eventually be installed.

Although advanced metering is required in order to meter and bill customer usage on hourly or shorter time intervals, advanced meters also provide the utility and customers with additional features and benefits such as real-time usage information, power quality information, outage notification, remote connect/disconnect, and more. Therefore, this study and detailed business case analysis focuses on paths which deploy advanced technology to all RPU customers; the Mandatory Rates / Mandatory Technology and Voluntary Rates / Mandatory Technology approaches. Paths A1 through A4 provide customers with service options and access to usage information but do not provide RPU real-time status and health information across the entire distribution system.

4.1 VOLUNTARY RATES / MANDATORY TECHNOLOGY APPROACH

The current approach of offering General Service customers TOU rates voluntarily has not successfully enticed a significant number of RPU customers to adopt this rate and it is doubtful that additional General Service customers would adopt it as long as an average price alternative is available. RPU does not currently offer Residential customers a TOU rate option but will likely develop such an option in order to provide additional choice for Residential customers. As has been observed with the General Service TOU rate option, it is unclear if Residential customers would adopt this option in significant quantity.

Under the Voluntary Rates / Mandatory Technology approach, TOU rates will be offered voluntarily. Therefore, there is no justification for a widespread deployment of advanced metering infrastructure (AMI) right away. Only those customers adopting voluntary TOU rate structures and strategic locations identified by RPU would require that an advanced meter be installed at their location right away.

Advanced metering for TOU participants under a voluntary approach could be accomplished with stand alone technology, such as a Nighthawk meter, or through common infrastructure, such as smart meters and wireless fixed network AMR. Stand alone technologies, such as those offered by Nighthawk, utilize third-party communications and result in greater capital and operating costs per participant. Under this approach, RPU should deploy a wireless fixed network communications system and deploy compatible to replace current drive-by AMR activities and reduce meter reading costs.

All other non-participating customers could continue to be billed using their existing meter and average monthly rate structures. Usage information would continue to be provided to all customers through the OPOWER program.

Additionally, in the early years of deployment, if an RPU customer were not interested in participating in TOU rates but were interested in access to more detailed interval information on energy consumption, RPU could promote and/or facilitate two alternatives:

1. RPU could recommend “behind the meter” technology such as a home energy controller (Cisco) or an energy monitoring system (The Energy Detective) that customers may install and utilize to manage energy usage on their own. This system would operate entirely on the customer side of the meter, connecting directly to the customer’s current electrical meter or electrical panel. RPU would have no involvement in its measurements or access to data generated.
2. Alternatively, RPU could offer to install an advanced meter at the customer location in conjunction with a compatible energy monitoring display, possibly on a cost-share basis. This energy monitoring display would be equivalent to the display included in the previous alternative; however, it would receive energy consumption information via ZigBee, directly from the advanced meter. RPU would select and install the advanced meter and energy monitoring display and have full access to the consumption data stored by the meter through the fixed network AMR or with RPU’s current drive-by AMR system, allowing RPU to gather data when convenient.

To further accommodate and encourage those RPU customers who are interested in monitoring and managing their energy consumption, RPU should make information pertaining to its day ahead wholesale power cost available to all customers. This could be accomplished via the RPU internet site or sent to interested customers through email, text, or other messaging methods.

The Voluntary Rates / Mandatory Technology approach would eventually deploy advanced meters to the entire service territory over 15 years. In addition to TOU rate participants, strategic deployment of advanced meters across the system could provide valuable power quality and outage information early in the deployment. Power quality information from installed advanced meters, coupled with enhanced distribution automation and monitoring, on a statistical basis could allow RPU to conserve voltage, identify overloaded equipment, relieve congestion, and possibly provide automatic outage notification capabilities if the meters are enabled to communicate information in real-time. Real-time two-way communication requirements could utilize the wireless fixed network. Strategic deployment could allow RPU to obtain system level information quickly as remaining advanced meters are deployed through attrition, failure, and phased deployments over the 15 year period.

Additionally, if other advanced functionality were needed, such as remote and/or automatic connect/disconnect, advanced meters could be installed at select locations when justified.

Interval usage data from deployed smart meters could be transmitted and stored remotely. This service is offered by most meter manufacturers. Once deployment on the RPU system reaches a critical level, RPU may then choose to build a meter data management system that they operate independently.

As RPU builds experience and accommodations for select smart meter deployment, RPU could also move to bring load into the MISO market through demand response and ancillary service bids. Any customer that signed up for this program would be required to have an advanced meter installed along with a compatible home area network that would enable appliance controls. The meter would be necessary for proper verification of load controlled and revenue sharing.

Under the Voluntary Rates / Mandatory Technology approach, RPU may obtain smart grid functionality quickly through a limited and strategic deployment strategy, reducing annual costs in early years relative to a rapid deployment.

Challenges associated with the Voluntary Rates / Mandatory Technology approach will include:

1. Justifying the deployment of a robust and reliable fixed network communication system/provider for only select deployment of smart meters in the early years.

2. Promoting/encouraging/incentivizing customer participation in new voluntary services.
3. Backhauling, storing, managing, and utilizing smart meter data for billing, outage management, and distribution management.
4. Coupling meter power quality information with distribution automation and other RPU systems.

4.2 MANDATORY RATES / MANDATORY TECHNOLOGY APPROACH

Under a mandatory time varying rate structure approach for all customers, there would be specific dates at which customers will be moved to a new time varying rate structure. The design of the rate structures will determine billing impacts to customers, operational and performance impacts to the system, and how much data storage will be required for the billing meters.

The simplest form of time varying rates would be to use different monthly average retail rates on a seasonal basis. This type of varying price would not require a meter change out from the existing meters on the system; however, changes to RPU's billing process would be required. Average energy prices would simply change depending on the month.

If price variance was to be applied on shorter time intervals, for example on an hourly basis, advanced meters which measure, store, and transmit interval usage data would be required. Intervals down to five minutes are achievable with advanced meters but price variance by each hour is most common. Hourly or shorter time intervals are sufficient for RPU to effectively account for varying wholesale energy costs sourced from SMMPA and/or the MISO market.

Mandatory hourly or shorter TOU and/or CPP rate structures will require the installation of a system-wide advanced metering infrastructure, associated fixed network communication system, and meter data management system. Deployment of these meters and systems could occur over the next 4-5 years. This schedule would allow for an extensive customer education program to be coordinated with the installation so that the customer base may be adequately prepared for mandatory time varying pricing when required at their location. The consumer education program will be important in enabling RPU customers to take advantage of new information, tools, and programs designed to help them manage their energy usage and costs.

The decision to implement mandatory time-varying pricing structures and an advanced metering infrastructure will provide guidance on what other distribution system objectives RPU could be achieved and provide the foundational means with which to achieve them. For instance, advanced operational functionality such as remote connect/disconnect, prepaid metering, outage notification, etc. would all be achieved through the AMI rather than through separate alternative methods. It is important to understand that technology implementation alone will not successfully enable all the advanced features of the AMI and DA systems. RPU will also need to transform business processes and operations in anticipation of these new features and functionality in order to effectively utilize them to improve service and efficiency.

Challenges associated with the Mandatory Rates / Mandatory Technology will include:

1. Justification for the intense initial capital outlay associated with system-wide technology deployment.
2. Transforming the culture and operations of the utility to effectively manage, promote, and utilize the new functionalities and data to realize benefits quickly after deployment, thus justifying the investment.
3. Backhauling, storing, managing, and utilizing smart meter data for billing, outage management, and distribution management.
4. Measuring and verifying the performance improvement impacts of the new systems from economic, customer service, and reliability perspectives.

4.3 COST OF APPROACHES COMPARISON

As mentioned in Section 4.1, a voluntary approach could be accomplished with standalone devices. However, if significant participation is desired and expected, utilization of smart meters and cummuncations infrastructure results in lower capital and operating costs per participant. So even if full deployment of advanced metering isn't achieved, the fixed network approach still provided better value.

Table 4-1 and Table 4-2 compare estimated costs of implementation for the various approaches calculated on a per participant basis. These calculations demonstrate how the cost efficiency of different voluntary approaches varies depending on the number of participants. For example, if 10,000 participants are achieved under the voluntary approaches, as demonstrated in Table 4-1, it would be less expensive, per participant, to invest in a fixed network to facilitate communications. It is less expensive from both an initial capital expenditure perspective and from a recurring cost perspective. If substantially fewer participants are achieved, as demonstrated in Table 4-2, it would be less expensive per participant to invest in standalone devices. However, standalone devices result in higher recurring costs and, over time, could result in more lifetime expense relative to investing in a fixed network. Additionally, standalone devices may not be compatible with a future deployment of advanced technologies and communications systems, whereas, a fixed network and voluntary smart meters will be compatible with a future full AMI deployment, should it be pursued.

Table 4-1: Cost Comparison of Voluntary (10,000 participants) versus Mandatory

	Voluntary (Stand Alone)		**Voluntary (Fixed Network)**		**Mandatory**	
Participants	10,000		10,000		45,000	
Feature	**Technology**	**$/location**	**Technology**	**$/location**	**Technology**	**$/location**
Remote Connect / Disconnect	Collar	$295 (+$2/mo)	Collar	$150	Included	
	Nighthawk Meter	$305 (+$2/mo)	Smart Meter w/ C/D	$200		
Hourly Interval Data	Smart Meter	$200	Smart Meter	$200	Included	
Outage Notification	Nighthawk Meter	$305 (+$2/mo)	Smart Meter		Included	
			Current Transformers	$200		
Real-time Power Quality Monitoring	Specialized Collar	$295 (+$2/mo)	Smart Meter	$200	Included	
	Nighthawk Meter	$305 (+$2/mo)	Cap Bank Controllers	$7,500		
Remote On-Demand Reads	Specialized Collar	$295 (+$2/mo)	Included		Included	
	Nighthawk Meter	$305 (+$2/mo)				
ePortal	Included		Included		Included	
MDMS	Remote host (Itron)	$1/mo	Remote host (Itron)	$1/mo	RPU Data Center	$12
AMI	N/A		N/A		AMI Solution	$260
Fixed Network	N/A		Itron Fixed Network	$70	Itron Fixed Network	$15
Fiber Upgrades	N/A		Routers/SONET	$25	Routers/SONET	$6
CIS Upgrades	Expansion Pack 5	$44	Expansion Pack 5	$44	Expansion Pack 5	$10
Total $/Location		**$349**		**$339**		**$303**
		(+$3.00/mo)		**(+$1.00/mo)**		**(+$0.40/mo)**
Total	**10000 participants**	**3,490,000**	**10000 participants**	**3,386,000**	**45000 participants**	**$13,636,000**
		(+$30000/mo)		**(+$10000/mo)**		**(+$17,000/mo)**
DA Upgrades	Various	$9,079,000	Various	$9,079,000	Various	$9,079,000
Total CapEx		**12,569,000**		**12,465,000**		**22,715,000**

Table 4-2: Cost Comparison of Voluntary (4,000 participants) versus Mandatory

	Voluntary (Stand Alone)		**Voluntary (Fixed Network)**		**Mandatory**	
Participants	4,000		4,000		45,000	
Feature	**Technology**	**$/location**	**Technology**	**$/location**	**Technology**	**$/location**
Remote Connect / Disconnect	Collar	$295 (+$2/mo)	Collar	$150	Included	
	Nighthawk Meter	$305 (+$2/mo)	Smart Meter w/ C/D	$200		
Hourly Interval Data	Smart Meter	$200	Smart Meter	$200	Included	
Outage Notification	Nighthawk Meter	$305 (+$2/mo)	Smart Meter		Included	
			Current Transformers	$200		
Real-time Power Quality Monitoring	Specialized Collar	$295 (+$2/mo)	Smart Meter	$200	Included	
	Nighthawk Meter	$305 (+$2/mo)	Cap Bank Controllers	$7,500		
Remote On-Demand Reads	Specialized Collar	$295 (+$2/mo)	Included		Included	
	Nighthawk Meter	$305 (+$2/mo)				
ePortal	Included		Included		Included	
MDMS	Remote host (Itron)	$1/mo	Remote host (Itron)	$1/mo	RPU Data Center	$12
AMI	N/A		N/A		AMI Solution	$260
Fixed Network	N/A		Itron Fixed Network	$174	Itron Fixed Network	$15
Fiber Upgrades	N/A		Routers/SONET	$63	Routers/SONET	$6
CIS Upgrades	Expansion Pack 5	$110	Expansion Pack 5	$110	Expansion Pack 5	$10
Total $/Location		**$415**		**$547**		**$303**
		(+$3.00/mo)		**(+$1.00/mo)**		**(+$0.40/mo)**
Total	**4000 participants**	**1,660,000**	**4000 participants**	**2,186,000**	**45000 participants**	**$13,636,000**
		(+$12000/mo)		**(+$4000/mo)**		**(+$17,000/mo)**
DA Upgrades	Various	$9,079,000	Various	$9,079,000	Various	$9,079,000
Total CapEx		**10,739,000**		**11,265,000**		**22,715,000**

The communications systems necessary to support a voluntary fixed network and mandatory approaches are similar, consisting of a wireless fixed network including a combination of collector and repeater units across the service territory. Under the standalone voluntary column, specialty devices that provide specific features such as remote connect/disconnect, hourly interval data, outage notification, and customer power quality monitoring are assumed to include Nighthawk meters and/or collars with cellular communication capabilities. It is important to note that the voluntary approach with a fixed network system will allow RPU to control and scale communications with meters and other devices installed on the distribution system designed to reduce outage time and meet other distribution system objectives. It is also assumed that the system backbone would be upgraded and or configured to allow full coverage of the RPU territory under either approach.

SECTION 5

RPU SMART GRID COST BENEFIT ANALYSIS

5.0 RPU SMART GRID COST BENEFIT ANALYSIS

5.1 ECONOMIC IMPACTS OF SMART GRID TECHNOLOGIES ON RPU SYSTEM

The benefits to the adoption of smart grid objectives by RPU accrue to various parts of the Rochester community. These benefits can be seen by:

- RPU the utility
- RPU's customers
- Rochester as a community

Burns & McDonnell estimated the costs and the value of benefits under both a mandatory and voluntary approach. Assuming that under the voluntary approach, a full system deployment is eventually achieved within 15 years, analysis resulted in 15-year total cost estimates of $21.4 million under both approaches. This estimate assumes that DA equipment will be deployed on all of RPU's distribution feeders; however, it is possible that many ROU feeders may not require implementation of DA equipment such as capacitor bank controllers or automated switching. The main difference between the two approaches is in the scheduled equipment deployment. Under the mandatory approach, all AMI, DA, and back office equipment is assumed to be deployed within four years while the voluntary approach assumes a slower deployment of equipment over 15 years.

The alternative voluntary paths A1 through A4 were not analyzed in detail through a cost benefit evaluation. Path A1 provides RPU and customers the targeted benefit of TOU rate structures and interval metering. TOU rate structures should achieve some level of load shifting for RPU and enable those customers who participate to lower energy costs. Path A2 provides the targeted benefit of interval usage information for both RPU and participating customers. Paths A3 and A4 could be implemented at essentially no cost to RPU. The costs and benefits associated with these paths are primarily dependent on the number of customers who choose to participate and are difficult to estimate over a long-term analysis. Combinations of paths A1 through A4 may also be considered and each one accomplishes some level of exposure to Smart Grid technologies for RPU as well as customer engagement and improved information for willing participants.

Under the Voluntary Rates / Mandatory Technology approach, direct RPU benefits were estimated at $15.3 million, resulting in a simple payback greater than 15 years. Benefits to RPU Customers were estimated at $11.8 million. Under the Mandatory Rates / Mandatory Technology approach, direct RPU benefits were estimated at $18.9 million, resulting in simple payback greater than 15 years. Benefits to RPU Customers were estimated at $21.2 million.

Within this 15-year analysis, the Mandatory Rates / Mandatory Technology approach resulted in greater total benefits to RPU, its customers, and the Rochester community due to longer benefit accumulation within the analysis window. However, this approach presents a greater capital risk due to more intense expenditure over the initial four years relative to the Voluntary Rates / Mandatory Technology approach. The Voluntary Rates / Mandatory Technology approach resulted in less benefit accumulation within the analysis window but it does offer RPU the opportunity to strategically deploy equipment and subsequently evaluate its performance prior to continuing deployment of additional equipment. This presents a reduced capital risk and the potential to redirect select investments if warranted.

The estimated 15-year cash flows associated with each approach are charted in Figure 5-1 and Figure 5-2. The categories and 15-year totals of costs and benefits to RPU customers, RPU, and Rochester are summarized in Table 5-1 and Table 5-2 for the Voluntary Rates / Mandatory Technology and Mandatory Rates / Mandatory Technology approaches, respectively. Detailed cash flow analysis supporting these results is located in Appendix C. These estimates include the value of benefits to RPU customers, RPU operations, and the Rochester community.

Estimates and projections prepared by Burns & McDonnell and used in our analyses are based on Burns & McDonnell's experience, qualifications and judgment as a professional consultant. Information from publicly available sources was used by Burns & McDonnell to make assumptions with respect to costs, benefits, and future conditions. Burns & McDonnell has not independently verified such information and cannot guarantee its accuracy or completeness. While Burns & McDonnell believes the assumptions to be reasonable for the purposes of this report, it makes no assurance that the conditions assumed will, in fact, occur. Additionally, the estimates and projections prepared by Burns & McDonnell and contained herein reflect screening level assumptions. To the extent that actual future conditions differ from those assumed herein, the actual results will vary from those forecasted.

Figure 5-1: Cost Benefit Analysis Results (RPU Direct Benefits)

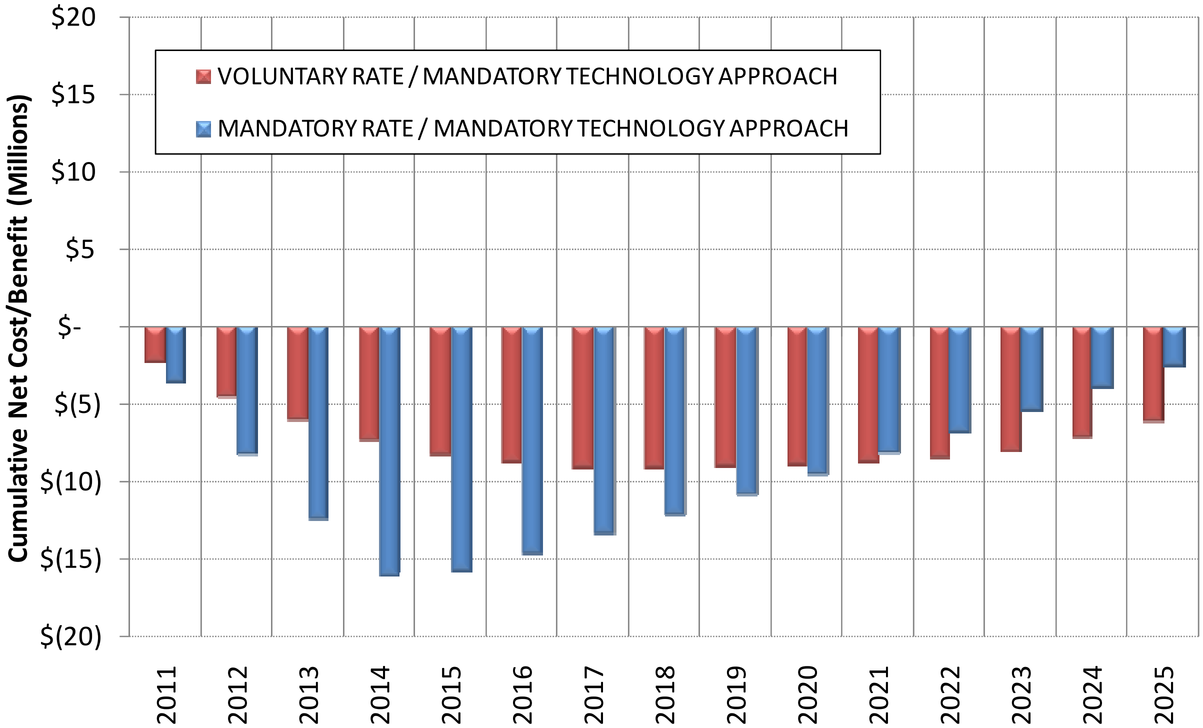

Figure 5-2: Cost Benefit Analysis Results (RPU & Customer Benefits)

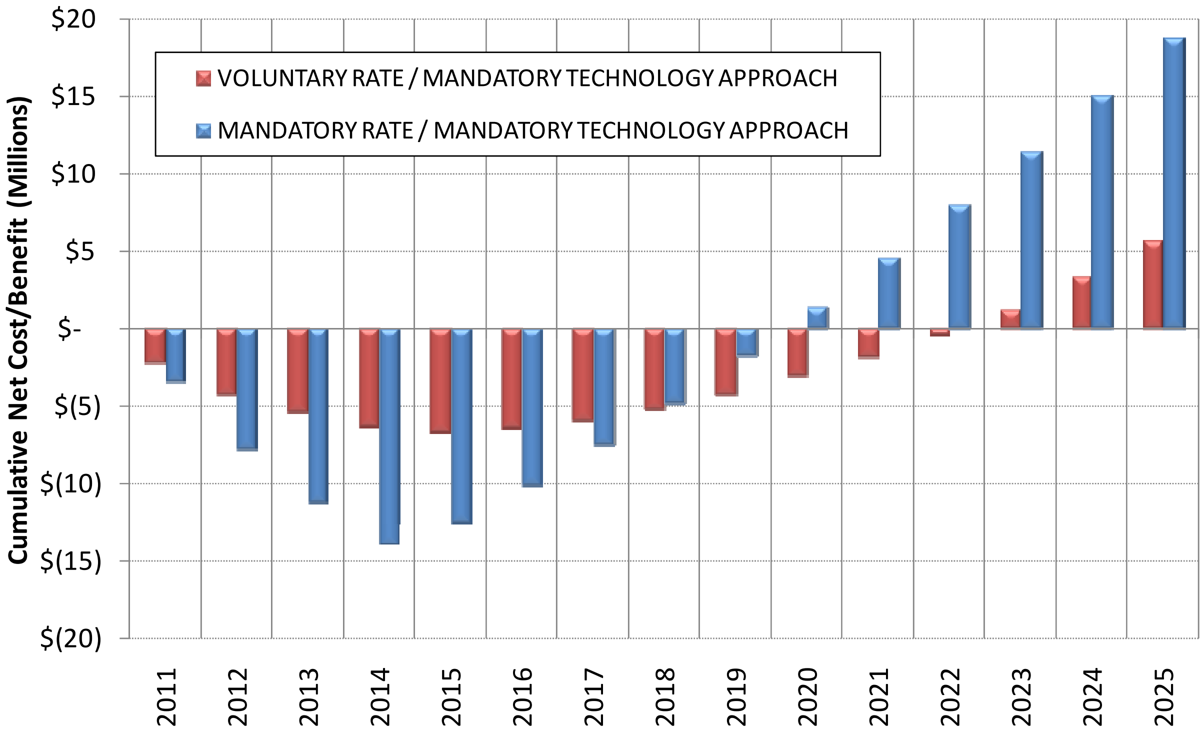

Table 5-1: Cost Benefit Results for Voluntary Rates / Mandatory Technology Approach

COSTS		15-YR TOTAL
DA Annual Capital Expenditures (Voluntary)	$	4,489,500
Advanced Meter Deployment Costs (Voluntary)	$	12,668,715
Itron Fixed Network Installation Costs (Voluntary)	$	696,000
Fiber Integration & Upgrade for Backhaul (Voluntary)	$	250,000
Back Office/Data Management Costs (Voluntary)	$	3,047,000
Marketing & Education Expenses	$	300,000
Total Cost	**$**	**21,451,215**

RPU DIRECT BENEFITS		15-YR TOTAL
Operational Savings		
Realized Savings from Avoided AMR (Voluntary)	$	4,582,072
Revenue from Increased Meter Accuracy (Voluntary)	$	2,905,824
Savings from Reduction in Outage Related Calls (Voluntary)	$	8,969
Savings from Reduced Outage Truck Rolls (Voluntary)	$	694,175
Savings from Reduced Transformer Oversizing (Voluntary)	$	619,799
Energy Savings		
Realized Savings from Reduced System Losses (Voluntary)	$	6,504,683
Demand Savings		
Realized Savings from Reduced System Losses (Voluntary)	$	-
Total RPU Direct Benefits	**$**	**15,315,523**
Net Cost/Benefit (Without Customer or Community Benefits)	**$**	**(6,135,692)**

RPU CUSTOMER BENEFITS		15-YR TOTAL
Energy Savings		
Energy Savings from Volt/VAR Optimization (Voluntary)	$	8,208,174
Energy Savings from Residential HEDs (Voluntary)	$	2,640,596
Energy Savings from Residential PCTs (Voluntary)	$	950,653
Demand Savings		
Demand Reduction from Volt/VAR Optimization (Voluntary)	$	-
Demand Reduction from Residential TOU (Voluntary)	$	-
Total RPU Customer Benefits	**$**	**11,799,423**
Net Cost/Benefit (Without Community Benefits)	**$**	**5,663,731**

RPU COMMUNITY BENEFITS		15-YR TOTAL
Environmental Value		
Value from Reduced AMR Emissions (Voluntary)	$	3,498
Value from Reduced Outage Response Emissions (Voluntary)	$	344
Value from Reduced Generation Emissions (Voluntary)	$	2,939,513
Service Value		
Enhanced Residential Service Value from Reduced Outage Time (Voluntary)	$	88,510
Enhanced Small C&I Service Value from Reduced Outage Time (Voluntary)	$	3,347,734
Enhanced Large C&I Service Value from Reduced Outage Time (Voluntary)	$	3,089,634
Total Community Benefits	**$**	**9,469,232**
Net Cost/Benefit	**$**	**15,132,962**

Table 5-2: Cost Benefit Results for Mandatory Rates / Mandatory Technology Approach

COSTS	15-YR TOTAL
DA Annual Capital Expenditures (Mandatory)	$ 4,489,500
Advanced Meter Deployment Costs (Mandatory)	$ 12,353,939
Itron Fixed Network Installation Costs (Mandatory)	$ 696,000
Fiber Integration & Upgrade for Backhaul (Mandatory)	$ 250,000
Back Office/Data Management Costs (Mandatory)	$ 3,326,500
Marketing & Education Expenses	$ 300,000
Total Cost	**$ 21,415,939**

RPU DIRECT BENEFITS	15-YR TOTAL
Operational Savings	
Realized Savings from Avoided AMR (Mandatory)	$ 4,582,072
Revenue from Increased Meter Accuracy (Mandatory)	$ 4,611,122
Savings from Reduction in Outage Related Calls (Mandatory)	$ 8,969
Savings from Reduced Outage Truck Rolls (Mandatory)	$ 861,625
Savings from Reduced Transformer Oversizing (Mandatory)	$ 769,308
Energy Savings	
Realized Savings from Reduced System Losses (Mandatory)	$ 8,047,182
Demand Savings	
Realized Savings from Reduced System Losses (Mandatory)	$ -
Total RPU Direct Benefits	**$ 18,880,278**
Net Cost/Benefit (Without Customer or Community Benefits)	**$ (2,535,661)**

RPU CUSTOMER BENEFITS	15-YR TOTAL
Energy Savings	
Energy Savings from Volt/VAR Optimization (Mandatory)	$ 10,154,632
Energy Savings from Residential HEDs (Mandatory)	$ 7,922,119
Energy Savings from Residential PCTs (Mandatory)	$ 3,168,756
Demand Savings	
Demand Reduction from Volt/VAR Optimization (Mandatory)	$ -
Demand Reduction from Residential TOU (Mandatory)	$ -
Total RPU Customer Benefits	**$ 21,245,507**
Net Cost/Benefit (Without Community Benefits)	**$ 18,709,846**

RPU COMMUNITY BENEFITS	15-YR TOTAL
Environmental Value	
Value from Reduced AMR Emissions (Mandatory)	$ 5,889
Value from Reduced Outage Response Emissions (Mandatory)	$ 432
Value from Reduced Generation Emissions (Mandatory)	$ 4,607,754
Service Value	
Enhanced Residential Service Value from Reduced Outage Time (Mandatory)	$ 110,953
Enhanced Small C&I Service Value from Reduced Outage Time (Mandatory)	$ 4,196,603
Enhanced Large C&I Service Value from Reduced Outage Time (Mandatory)	$ 3,873,867
Total Community Benefits	**$ 12,795,497**
Net Cost/Benefit	**$ 31,505,343**

Regardless of implementation approach, RPU would achieve greater information about their load, more efficient operations, improved customer service, increased choice for customers, and various other benefits for the Rochester community.

5.2 ADDITIONAL BENEFITS OF SMART GRID TECHNOLOGIES

Implementing Smart Grid technologies on the RPU distribution system will provide additional benefits to the organization, customers, and the community that are not quantified in this cost benefit analysis.

With improved visibility and real-time feedback of system health, RPU may have the opportunity to operate with less reserve margin due to improved accuracy of projected daily load profiles. Readily accessible historical load data and forecasting would lead to enhanced future planning and more efficient due diligence on future investments. In addition, RPU outage times would decrease due to improved source detection and response deployment, which would improve System Average Interruption Duration Index (SAIDI).

Smart meters and real-time communications allow for extensive support of distributed generation (DG) and customer owned renewable generation resources on the RPU system through net metering. System operators will have the capability to adapt the system to variable influx of DG power, whereas currently, this influx would be difficult to manage. Smart and net metering would also support Plug-in Hybrid Electric Vehicles (PHEV) and Electric Vehicles (EV) on the RPU system. In fact, the system could possibly utilize PHEV/EVs as distributed storage resources to meet capacity needs during peak demand periods.

RPU customers will benefit from Smart Grid technologies too. They will have access to their detailed energy usage information and have greater flexibility in paying for electricity. Real-time usage data will be provided through enhancing billing and various communication technologies such as In-Home-Displays (IHD) and web-based Energy Dashboards that will communicate directly with RPU's Meter Data Management System. With interval metering, RPU will offer customers choice and flexibility of energy rates and empower them to better manage their energy consumption. Conscious consumers would have the opportunity to shift and/or reduce energy usage to achieve lower bills and preserve the Earth's finite resources.

Customers will also receive higher customer satisfaction, be billed more accurately for the energy they use, and pay for only the energy they consume when they consume it. Real-time information and control to customer service representatives will improve the overall service that customers receive as problems will be resolved more quickly and requested changes will be enacted immediately. New digital meters will measure energy consumption more accurately and in greater detail. Automated communication of customer usage will eliminate estimated bills.

The Rochester community as a whole will benefit from Smart Grid technologies implemented on the RPU distribution system. TOU energy rates and improved energy consumption awareness will result in less energy consumption during peak periods and, likely, less total energy consumption on the RPU system. This will reduce the utilization of inefficient generating facilities and lower fossil fuel consumption resulting in reduced local and regional carbon (CO_2) emissions.

Power on the RPU system will be more reliable and of a higher quality due to enhanced voltage and power flow monitoring and controls. The system will experience less local outages and contribute to regional grid stability. Smart systems will more efficiently share power and relieve grid congestion. A reliable and high quality power system will support 21st century commerce in the Rochester area, potentially attracting and retaining innovative businesses.

5.3 COST BENEFIT ANALYSIS SUMMARY AND CONCLUSIONS

The decision on whether to transition customers to time varying pricing has a significant impact on the deployment strategy of devices on the system. The advanced meters used for obtaining billing information for time varying pricing provide many of the functions necessary to support other RPU smart grid objectives. Deployment of advanced meters can avoid the use of multiple separate add on devices to existing meters or separate devices from other manufacturers to provide desired functions.

The communication system necessary to support either approach presented in this analysis is the same. Under the Voluntary Rates / Mandatory Technology approach, the utilization of the system evolves slower, however it still provides value relative to alternatives. Either approach would allow for easy expansion of the system should RPU’s customer density increase or its territory expand.

The Smart Grid objectives identified and pursued by RPU can provide benefits to RPU, its customers and the community but will require capital investments.

* * * * *

SECTION 6

RECOMMENDATIONS

6.0 RECOMMENDATIONS

Based on Burns & McDonnell's experience and analysis, the following recommendations should be considered:

1) RPU should consider AMI technology (smart meters and communication network) as the best technology solution in order to achieve customer information and empowerment, power quality monitoring, outage detection, remote connect/disconnect, and demand side management capabilities. The alternative would be to pursue dedicated equipment for each function which would result in greater expense, less flexibility, and little to no future interoperability.

2) The industry is currently demonstrating that the average electricity consumer is not prepared to adopt TOU or any other time varying rate structures. More education and outreach must be accomplished to inform consumers on the costs to provide electrical service, how their behaviors impact that cost, and what they can do to reduce electricity consumption. Only after successful education should RPU consider mandatory TOU rate structures.

3) Future maintenance and upgrade activities on the RPU distribution system should support a long-term RPU Smart Grid vision. That is, upgrades and equipment replacements should consider technologies that will be compatible with RPU future Smart Grid objectives, should be scalable, and should be interoperable across vendors and other RPU systems.

4) Under either a voluntary or mandatory approach, RPU should consider the impacts of new quantities of information generated. The processes and capabilities to store and manage this data within the RPU information systems should be developed prior to field device installation.

5) Education and empowerment of the RPU customers may begin immediately. While RPU considers investment in technology and tools to improve system capabilities, education regarding the daily costs associated with generating and delivering electricity should begin immediately. Additionally, RPU could begin promoting the use of home energy information devices such as the Cisco home energy controller which can wirelessly read RPU's current electricity meters (ERT compatible) and are compatible with advanced meters (ZigBee).

6) RPU should upgrade their CIS to SAP CRM. This upgrade will enable RPU to utilize and bill according to additional usage information that will be generated by future technology implementations.

SECTION 7

IMPLEMENTATION PLAN

7.0 IMPLEMENTATION PLAN

In addition to the above recommendations, Burns & McDonnell recommends the following, high-level, implementation plan in accordance with a voluntary Smart Grid implementation approach:

Year 1:	– Consumer Education & Outreach on daily costs of energy generation – Begin marketing technology upgrades, smart meter/HED availability, new rate structures, and DSM programs – Begin Smart Meter & HED deployment to customers who demand real-time energy usage information on a cost-share basis – AMR Fixed Network & Fiber Backhaul Design – DA System Upgrade Design – MDMS Strategy (remote or local) and Design, if required – Customer Service Option Design (TOU rates, DSM programs, Smart Meter/HED technology acquisition, etc.)
Year 2:	– Continue marketing technology upgrades, smart meter availability, new rate structures, and DSM programs – Install AMR Fixed Network & Fiber Backhaul Upgrades – Begin Smart Meter deployment to strategic customer locations – Continue Smart Meter & HED deployment to cost-share customers – MDMS Initiation or Installation – Upgrade CIS with SAP Expansion Pack 5 – Begin DA System upgrade installations on poor performing feeders
Year 3:	– Evaluate performance of metering and DA deployments – Continue Smart Meter deployment to strategic customer locations – Continue Smart Meter & HED deployment to cost-share customers – Continue DA System upgrade installations – Interface MDMS with CIS and OMS – Upgrade to Telvent DMS and interface it with OMS – Offer new rate structures (TOU and/or CPP) and DSM Programs to customers on a voluntary basis
Year 4:	– Evaluate performance of metering and DA deployments – Continue Smart Meter deployment to strategic customer locations – Continue Smart Meter & HED deployment to cost-share customers – Continue DA System upgrade installations – Offer new rate structures (TOU and/or CPP) and DSM Programs to customers on a voluntary basis
Year 5+:	– Evaluate performance of metering and DA deployments – Continue technology deployments on voluntary and cost-share basis – Continue technology deployments on strategic and retirement basis

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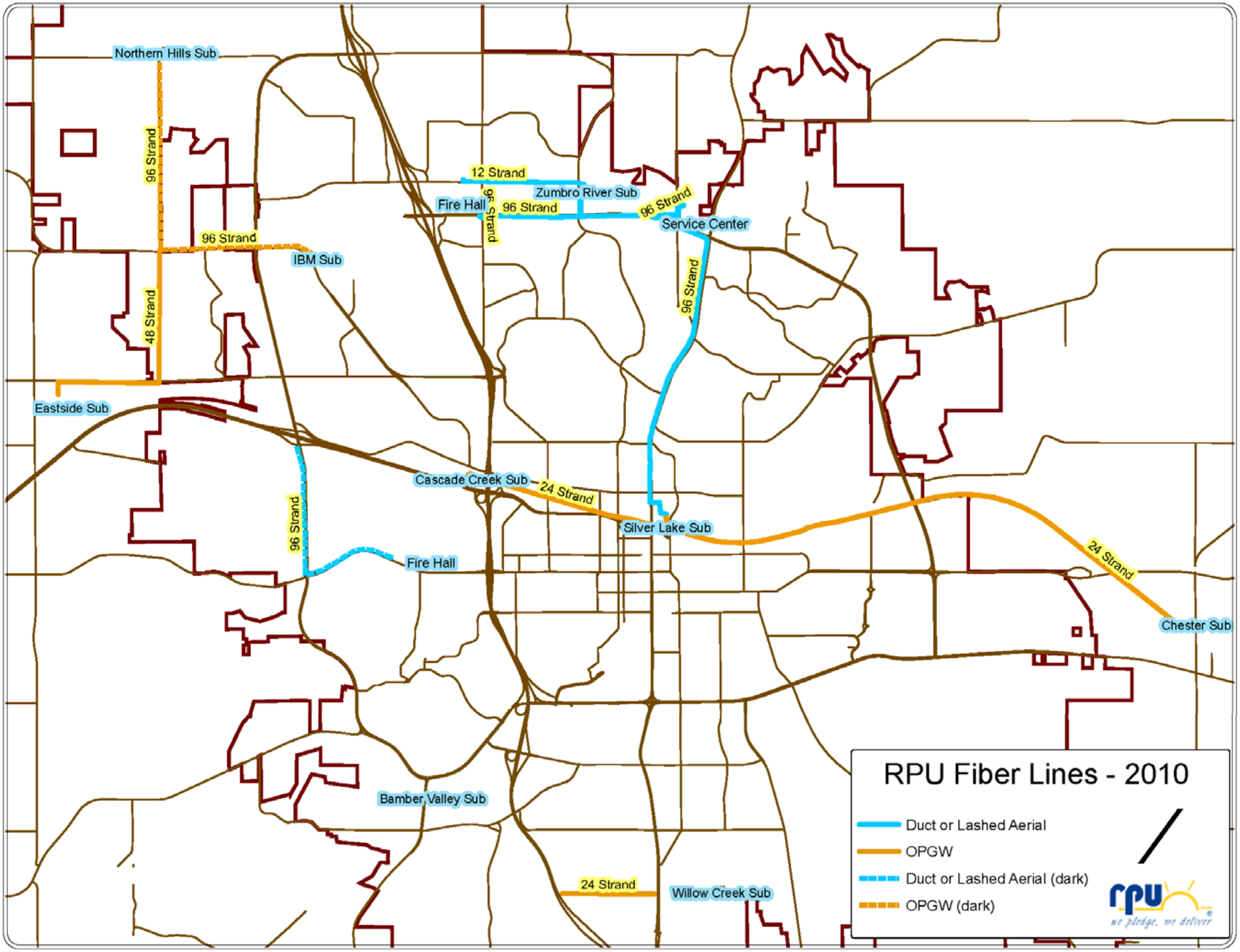
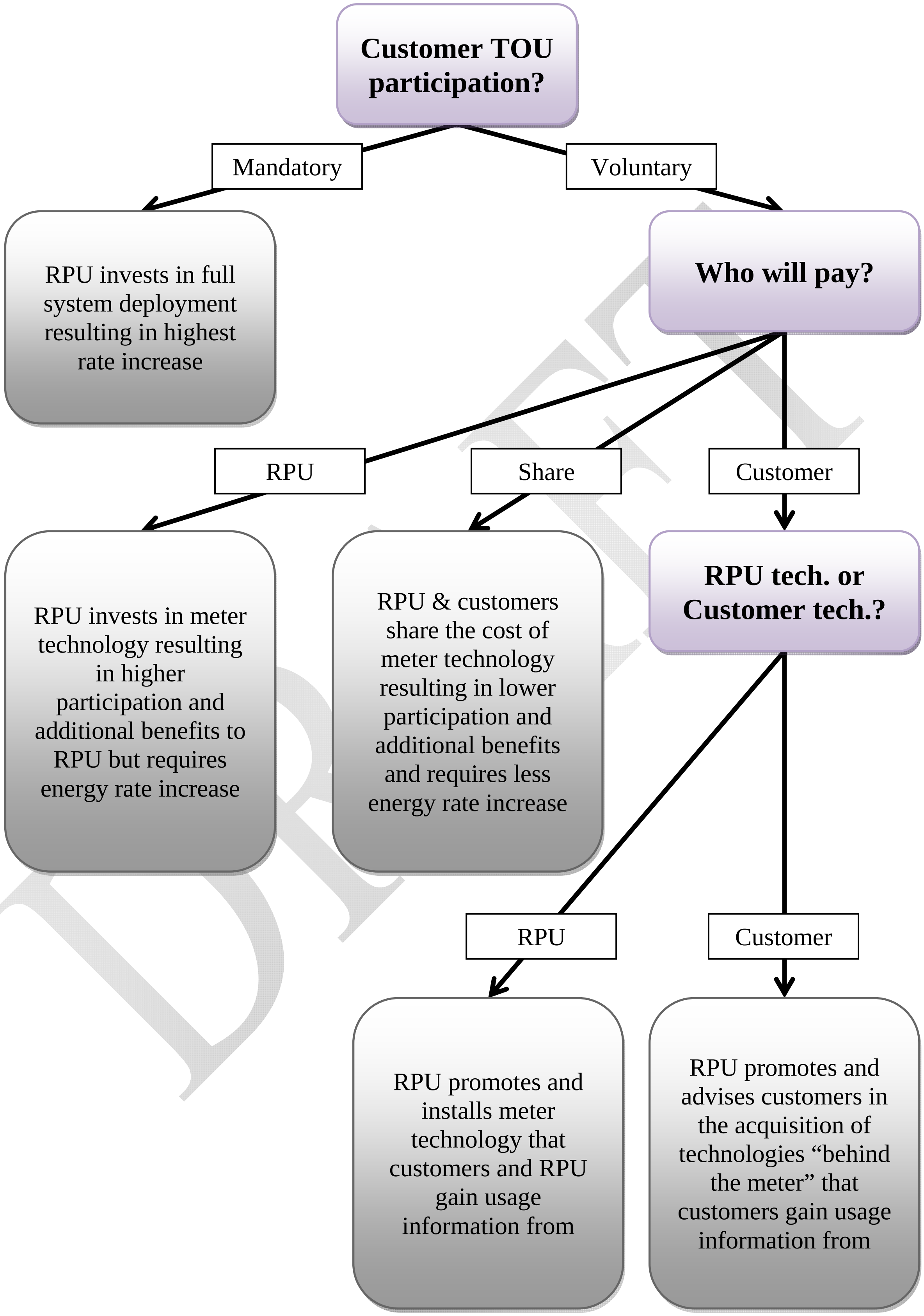
APPENDIX A

RPU FIBER NETWORK LAYOUT


Northern Hills Sub
96 Strand
48 Strand
96 Strand
IBM Sub
Eastside Sub
12 Strand
Zumbro River Sub
Fire Hall
96 Strand
96 Strand
96 Strand
Service Center
96 Strand
Cascade Creek Sub
24 Strand
Silver Lake Sub
96 Strand
Fire Hall
24 Strand
Chester Sub
Bamber Valley Sub
24 Strand
Willow Creek Sub
RPU Fiber Lines - 2010
Duct or Lashed Aerial
OPGW
Duct or Lashed Aerial (dark)
OPGW (dark)
rpu
we pledge, we deliver

APPENDIX B

RPU SMART GRID DECISION TREE


Customer TOU participation?
Mandatory
Voluntary
RPU invests in full system deployment resulting in highest rate increase
Who will pay?
RPU
Share
Customer
RPU invests in meter technology resulting in higher participation and additional benefits to RPU but requires energy rate increase
RPU & customers share the cost of meter technology resulting in lower participation and additional benefits and requires less energy rate increase
RPU tech. or Customer tech.?
RPU
Customer
RPU promotes and installs meter technology that customers and RPU gain usage information from
RPU promotes and advises customers in the acquisition of technologies “behind the meter” that customers gain usage information from

APPENDIX C
RPU COST BENEFIT CASH FLOW ANALYSIS SUMMARY

Economic Impacts from Smart Grid Implementation and Enhanced Operations - VOLUNTARY RATE / MANDATORY TECHNOLOGY APPROACH

VOLUNTARY RATE / MANDATORY TECHNOLOGY APPROACH

COSTS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	15-YR TOTAL
DA Annual Capital Expenditures (Voluntary)	$ 897,900	$ 897,900	$ 897,900	$ 897,900	$ 897,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,489,500
Advanced Meter Deployment Costs (Voluntary)	$ 569,882	$ 630,005	$ 633,442	$ 752,595	$ 872,925	$ 994,440	$ 999,712	$ 1,005,013	$ 1,010,344	$ 1,015,704	$ 1,021,094	$ 1,026,514	$ 1,031,965	$ 551,001	$ 554,080	$ 12,668,715
Itron Fixed Network Installation Costs (Voluntary)	$ 104,400	$ 174,000	$ 208,800	$ 208,800	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 696,000
Fiber Integration & Upgrade for Backhaul (Voluntary)	$ 37,500	$ 62,500	$ 75,000	$ 75,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 250,000
Back Office/Data Management Costs (Voluntary)	$ 745,000	$ 750,000	$ 35,000	$ 40,000	$ 45,000	$ 300,000	$ 340,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 3,047,000
Marketing & Education Expenses	$ 50,000	$ 100,000	$ 100,000	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 300,000
Total Cost	**$ 2,404,682**	**$ 2,614,405**	**$ 1,950,142**	**$ 2,024,295**	**$ 1,815,825**	**$ 1,294,440**	**$ 1,339,712**	**$ 1,104,013**	**$ 1,109,344**	**$ 1,114,704**	**$ 1,120,094**	**$ 1,125,514**	**$ 1,130,965**	**$ 650,001**	**$ 653,080**	**$ 21,451,215**

RPU DIRECT BENEFITS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	15-YR TOTAL
Operational Savings																
Realized Savings from Avoided AMR (Voluntary)	$ 44,288	$ 120,462	$ 215,025	$ 313,322	$ 319,588	$ 325,980	$ 332,499	$ 339,149	$ 345,932	$ 352,851	$ 359,908	$ 367,106	$ 374,448	$ 381,937	$ 389,576	$ 4,582,072
Revenue from Increased Meter Accuracy (Voluntary)	$ 14,258	$ 30,540	$ 47,475	$ 68,109	$ 92,643	$ 121,288	$ 151,050	$ 181,962	$ 214,059	$ 247,376	$ 281,949	$ 317,816	$ 355,013	$ 378,826	$ 403,460	$ 2,905,824
Savings from Reduction in Outage Related Calls (Voluntary)	$ 118	$ 240	$ 367	$ 499	$ 636	$ 649	$ 662	$ 675	$ 689	$ 703	$ 717	$ 731	$ 746	$ 761	$ 776	$ 8,969
Savings from Reduced Outage Truck Rolls (Voluntary)	$ 7,000	$ 14,280	$ 21,848	$ 30,011	$ 38,794	$ 42,043	$ 45,407	$ 48,888	$ 52,490	$ 56,217	$ 60,072	$ 64,059	$ 68,181	$ 70,993	$ 73,891	$ 694,175
Savings from Reduced Transformer Oversizing (Voluntary)	$ 6,250	$ 12,750	$ 19,508	$ 26,796	$ 34,638	$ 37,539	$ 40,542	$ 43,650	$ 46,866	$ 50,194	$ 53,636	$ 57,195	$ 60,876	$ 63,387	$ 65,974	$ 619,799
Energy Savings																
Realized Savings from Reduced System Losses (Voluntary)	$ 62,753	$ 128,657	$ 197,829	$ 273,097	$ 354,790	$ 386,426	$ 419,427	$ 453,841	$ 489,718	$ 527,110	$ 566,071	$ 606,656	$ 648,922	$ 679,068	$ 710,319	$ 6,504,683
Demand Savings																
Realized Savings from Reduced System Losses (Voluntary)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total RPU Direct Benefits	**$ 134,666**	**$ 306,928**	**$ 502,051**	**$ 711,832**	**$ 841,090**	**$ 913,925**	**$ 989,587**	**$ 1,068,166**	**$ 1,149,755**	**$ 1,234,452**	**$ 1,322,353**	**$ 1,413,563**	**$ 1,508,185**	**$ 1,574,972**	**$ 1,643,996**	**$ 15,315,523**
Net Cost/Benefit (Without Customer or Community Benefits)	**$ (2,270,016)**	**$ (2,307,476)**	**$ (1,448,091)**	**$ (1,312,462)**	**$ (974,735)**	**$ (380,515)**	**$ (350,125)**	**$ (35,847)**	**$ 40,412**	**$ 119,748**	**$ 202,259**	**$ 288,049**	**$ 377,220**	**$ 924,971**	**$ 990,916**	**$ (6,135,692)**
Cum. Net Cost/Benefit (Without Customer or Community Benefits)	**$ (2,270,016)**	**$ (4,577,493)**	**$ (6,025,584)**	**$ (7,338,046)**	**$ (8,312,781)**	**$ (8,693,296)**	**$ (9,043,420)**	**$ (9,079,267)**	**$ (9,038,855)**	**$ (8,919,108)**	**$ (8,716,848)**	**$ (8,428,800)**	**$ (8,051,579)**	**$ (7,126,608)**	**$ (6,135,692)**	

year$	2011
discount rate	5.0%

NPV (2011$)	**$ (6,703,442)**
Simple Payback Period	**Over 15 yrs**

RPU CUSTOMER BENEFITS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	15-YR TOTAL
Energy Savings																
Energy Savings from Volt/VAR Optimization (Voluntary)	$ 79,188	$ 162,350	$ 249,638	$ 344,617	$ 447,705	$ 487,626	$ 529,269	$ 572,696	$ 617,969	$ 665,154	$ 714,318	$ 765,531	$ 818,866	$ 856,907	$ 896,342	$ 8,208,174
Energy Savings from Residential HEDs (Voluntary)	$ 5,563	$ 23,632	$ 55,348	$ 77,158	$ 100,859	$ 126,530	$ 154,349	$ 184,455	$ 216,999	$ 252,085	$ 263,546	$ 275,581	$ 288,157	$ 301,300	$ 315,034	$ 2,640,596
Energy Savings from Residential PCTs (Voluntary)	$ 2,006	$ 8,504	$ 19,930	$ 27,782	$ 36,314	$ 45,545	$ 55,577	$ 66,404	$ 78,107	$ 90,744	$ 94,877	$ 99,230	$ 103,744	$ 108,460	$ 113,428	$ 950,653
Demand Savings																
Demand Reduction from Volt/VAR Optimization (Voluntary)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Reduction from Residential TOU (Voluntary)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total RPU Customer Benefits	**$ 86,756**	**$ 194,487**	**$ 324,916**	**$ 449,557**	**$ 584,877**	**$ 659,702**	**$ 739,195**	**$ 823,555**	**$ 913,075**	**$ 1,007,982**	**$ 1,072,741**	**$ 1,140,342**	**$ 1,210,766**	**$ 1,266,667**	**$ 1,324,804**	**$ 11,799,423**
Net Cost/Benefit (Without Community Benefits)	**$ (2,183,260)**	**$ (2,112,990)**	**$ (1,123,175)**	**$ (862,906)**	**$ (389,857)**	**$ 279,187**	**$ 389,070**	**$ 787,708**	**$ 953,487**	**$ 1,127,730**	**$ 1,275,000**	**$ 1,428,390**	**$ 1,587,986**	**$ 2,191,638**	**$ 2,315,720**	**$ 5,663,731**
Cum. Net Cost/Benefit (Without Community Benefits)	**$ (2,183,260)**	**$ (4,296,250)**	**$ (5,419,425)**	**$ (6,282,330)**	**$ (6,672,188)**	**$ (6,393,001)**	**$ (6,003,930)**	**$ (5,216,222)**	**$ (4,262,735)**	**$ (3,135,005)**	**$ (1,860,004)**	**$ (431,614)**	**$ 1,156,372**	**$ 3,348,011**	**$ 5,663,731**	

NPV (2011$)	**$ 994,670**
Simple Payback Period	**12.3 yrs**

RPU COMMUNITY BENEFITS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	15-YR TOTAL
Environmental Value																
Value from Reduced AMR Emissions (Voluntary)	$ 22	$ 44	$ 67	$ 93	$ 124	$ 160	$ 196	$ 231	$ 267	$ 302	$ 338	$ 373	$ 409	$ 427	$ 444	$ 3,498
Value from Reduced Outage Response Emissions (Voluntary)	$ 4	$ 8	$ 12	$ 17	$ 21	$ 22	$ 24	$ 25	$ 26	$ 28	$ 29	$ 30	$ 32	$ 32	$ 33	$ 344
Value from Reduced Generation Emissions (Voluntary)	$ 29,239	$ 61,519	$ 96,933	$ 131,351	$ 167,428	$ 182,245	$ 197,397	$ 212,887	$ 228,727	$ 244,919	$ 256,516	$ 268,254	$ 280,117	$ 287,337	$ 294,647	$ 2,939,513
Service Value																
Enhanced Residential Service Value from Reduced Outage Time (Voluntary)	$ 1,016	$ 2,042	$ 3,078	$ 4,166	$ 5,306	$ 5,665	$ 6,029	$ 6,395	$ 6,766	$ 7,140	$ 7,517	$ 7,898	$ 8,282	$ 8,497	$ 8,714	$ 88,510
Enhanced Small C&I Service Value from Reduced Outage Time (Voluntary)	$ 38,419	$ 77,213	$ 116,409	$ 157,560	$ 200,688	$ 214,302	$ 228,042	$ 241,908	$ 255,900	$ 270,018	$ 284,262	$ 298,701	$ 313,272	$ 321,416	$ 329,625	$ 3,347,734
Enhanced Large C&I Service Value from Reduced Outage Time (Voluntary)	$ 35,535	$ 71,415	$ 107,640	$ 145,652	$ 185,472	$ 198,002	$ 210,643	$ 223,394	$ 236,256	$ 249,228	$ 262,310	$ 275,503	$ 288,806	$ 296,176	$ 303,600	$ 3,089,634
Total Community Benefits	**$ 104,235**	**$ 212,241**	**$ 324,139**	**$ 438,838**	**$ 559,039**	**$ 600,397**	**$ 642,331**	**$ 684,841**	**$ 727,941**	**$ 771,634**	**$ 810,972**	**$ 850,759**	**$ 890,918**	**$ 913,884**	**$ 937,063**	**$ 9,469,232**
Net Cost/Benefit	**$ (2,079,025)**	**$ (1,900,749)**	**$ (799,036)**	**$ (424,067)**	**$ 169,181**	**$ 879,584**	**$ 1,031,401**	**$ 1,472,549**	**$ 1,681,428**	**$ 1,899,364**	**$ 2,085,972**	**$ 2,279,150**	**$ 2,478,904**	**$ 3,105,523**	**$ 3,252,783**	**$ 15,132,962**
Cumulative Net Cost/Benefit	**$ (2,079,025)**	**$ (3,979,774)**	**$ (4,778,810)**	**$ (5,202,877)**	**$ (5,033,695)**	**$ (4,154,112)**	**$ (3,122,711)**	**$ (1,650,162)**	**$ 31,266**	**$ 1,930,631**	**$ 4,016,603**	**$ 6,295,753**	**$ 8,774,657**	**$ 11,880,179**	**$ 15,132,962**	

IRR ($)	**16.2%**
NPV (2011$)	**$ 7,309,917**
Simple Payback Period	**9 yrs**

Economic Impacts from Smart Grid Implementation and Enhanced Operations - MANDATORY RATE / MANDATORY TECHNOLOGY APPROACH

MANDATORY RATE / MANDATORY TECHNOLOGY APPROACH

COSTS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	15-YR TOTAL
DA Annual Capital Expenditures (Mandatory)	$ 897,900	$ 897,900	$ 897,900	$ 897,900	$ 897,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,489,500
Advanced Meter Deployment Costs (Mandatory)	$ 1,709,646	$ 2,920,930	$ 3,511,418	$ 3,529,265	$ 59,013	$ 59,605	$ 60,202	$ 60,806	$ 61,415	$ 62,031	$ 62,653	$ 63,281	$ 63,915	$ 64,556	$ 65,203	$ 12,353,939
Itron Fixed Network Installation Costs (Mandatory)	$ 104,400	$ 174,000	$ 208,800	$ 208,800	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 696,000
Fiber Integration & Upgrade for Backhaul (Mandatory)	$ 37,500	$ 62,500	$ 75,000	$ 75,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 250,000
Back Office/Data Management Costs (Mandatory)	$ 970,000	$ 1,069,500	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 99,000	$ 3,326,500
Marketing & Education Expenses	$ 50,000	$ 100,000	$ 100,000	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 300,000
Total Cost	**$ 3,769,446**	**$ 5,224,830**	**$ 4,892,118**	**$ 4,859,965**	**$ 1,055,913**	**$ 158,605**	**$ 159,202**	**$ 159,806**	**$ 160,415**	**$ 161,031**	**$ 161,653**	**$ 162,281**	**$ 162,915**	**$ 163,556**	**$ 164,203**	**$ 21,415,939**

RPU DIRECT BENEFITS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	15-YR TOTAL
Operational Savings																
Realized Savings from Avoided AMR (Mandatory)	$ 44,288	$ 120,462	$ 215,025	$ 313,322	$ 319,588	$ 325,980	$ 332,499	$ 339,149	$ 345,932	$ 352,851	$ 359,908	$ 367,106	$ 374,448	$ 381,937	$ 389,576	$ 4,582,072
Revenue from Increased Meter Accuracy (Mandatory)	$ 42,773	$ 117,795	$ 210,643	$ 307,165	$ 314,875	$ 322,779	$ 330,880	$ 339,185	$ 347,699	$ 356,426	$ 365,372	$ 374,543	$ 383,944	$ 393,581	$ 403,460	$ 4,611,122
Savings from Reduction in Outage Related Calls (Mandatory)	$ 118	$ 240	$ 367	$ 499	$ 636	$ 649	$ 662	$ 675	$ 689	$ 703	$ 717	$ 731	$ 746	$ 761	$ 776	$ 8,969
Savings from Reduced Outage Truck Rolls (Mandatory)	$ 9,800	$ 22,848	$ 37,871	$ 53,485	$ 60,616	$ 61,829	$ 63,065	$ 64,326	$ 65,613	$ 66,925	$ 68,264	$ 69,629	$ 71,022	$ 72,442	$ 73,891	$ 861,625
Savings from Reduced Transformer Oversizing (Mandatory)	$ 8,750	$ 20,400	$ 33,813	$ 47,754	$ 54,122	$ 55,204	$ 56,308	$ 57,434	$ 58,583	$ 59,755	$ 60,950	$ 62,169	$ 63,412	$ 64,680	$ 65,974	$ 769,308
Energy Savings																
Realized Savings from Reduced System Losses (Mandatory)	$ 87,855	$ 205,851	$ 342,904	$ 486,707	$ 554,359	$ 568,273	$ 582,537	$ 597,159	$ 612,147	$ 627,512	$ 643,263	$ 659,409	$ 675,960	$ 692,927	$ 710,319	$ 8,047,182
Demand Savings																
Realized Savings from Reduced System Losses (Mandatory)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total RPU Direct Benefits	**$ 193,582**	**$ 487,596**	**$ 840,622**	**$ 1,208,932**	**$ 1,304,197**	**$ 1,334,714**	**$ 1,365,952**	**$ 1,397,930**	**$ 1,430,664**	**$ 1,464,172**	**$ 1,498,474**	**$ 1,533,587**	**$ 1,569,532**	**$ 1,606,328**	**$ 1,643,996**	**$ 18,880,278**
Net Cost/Benefit (Without Customer or Community Benefits)	**$ (3,575,864)**	**$ (4,737,234)**	**$ (4,051,496)**	**$ (3,651,033)**	**$ 248,284**	**$ 1,176,109**	**$ 1,206,750**	**$ 1,238,124**	**$ 1,270,248**	**$ 1,303,141**	**$ 1,336,821**	**$ 1,371,306**	**$ 1,406,617**	**$ 1,442,772**	**$ 1,479,793**	**$ (2,535,661)**
Cum. Net Cost/Benefit (Without Customer or Community Benefits)	**$ (3,575,864)**	**$ (8,313,098)**	**$ (12,364,594)**	**$ (16,015,627)**	**$ (15,767,343)**	**$ (14,591,234)**	**$ (13,384,484)**	**$ (12,146,360)**	**$ (10,876,112)**	**$ (9,572,970)**	**$ (8,236,149)**	**$ (6,864,843)**	**$ (5,458,226)**	**$ (4,015,454)**	**$ (2,535,661)**	

year$	2011
discount rate	5.0%

NPV (2011$)	**$ (6,392,035)**
Simple Payback Period	**Over 15 yrs**

RPU CUSTOMER BENEFITS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	15-YR TOTAL
Energy Savings																
Energy Savings from Volt/VAR Optimization (Mandatory)	$ 110,863	$ 259,760	$ 432,706	$ 614,169	$ 699,538	$ 717,097	$ 735,096	$ 753,547	$ 772,461	$ 791,850	$ 811,725	$ 832,099	$ 852,985	$ 874,395	$ 896,342	$ 10,154,632
Energy Savings from Residential HEDs (Mandatory)	$ 16,701	$ 70,922	$ 166,045	$ 231,516	$ 302,532	$ 379,637	$ 463,047	$ 553,366	$ 650,946	$ 756,254	$ 790,695	$ 826,799	$ 864,531	$ 903,961	$ 945,167	$ 7,922,119
Energy Savings from Residential PCTs (Mandatory)	$ 6,685	$ 28,374	$ 66,434	$ 92,606	$ 121,004	$ 151,864	$ 185,209	$ 221,347	$ 260,358	$ 302,480	$ 316,311	$ 330,708	$ 345,812	$ 361,534	$ 378,028	$ 3,168,756
Demand Savings																
Demand Reduction from Volt/VAR Optimization (Mandatory)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Demand Reduction from Residential TOU (Mandatory)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total RPU Customer Benefits	**$ 134,249**	**$ 359,056**	**$ 665,185**	**$ 938,291**	**$ 1,123,074**	**$ 1,248,598**	**$ 1,383,352**	**$ 1,528,260**	**$ 1,683,765**	**$ 1,850,584**	**$ 1,918,731**	**$ 1,989,607**	**$ 2,063,328**	**$ 2,139,891**	**$ 2,219,537**	**$ 21,245,507**
Net Cost/Benefit (Without Community Benefits)	**$ (3,441,615)**	**$ (4,378,178)**	**$ (3,386,311)**	**$ (2,712,742)**	**$ 1,371,358**	**$ 2,424,707**	**$ 2,590,102**	**$ 2,766,384**	**$ 2,954,013**	**$ 3,153,725**	**$ 3,255,552**	**$ 3,360,913**	**$ 3,469,945**	**$ 3,582,663**	**$ 3,699,330**	**$ 18,709,846**
Cum. Net Cost/Benefit (Without Community Benefits)	**$ (3,441,615)**	**$ (7,819,792)**	**$ (11,206,103)**	**$ (13,918,845)**	**$ (12,547,488)**	**$ (10,122,781)**	**$ (7,532,678)**	**$ (4,766,295)**	**$ (1,812,282)**	**$ 1,341,444**	**$ 4,596,995**	**$ 7,957,909**	**$ 11,427,854**	**$ 15,010,517**	**$ 18,709,846**	

NPV (2011$)	**$ 7,597,237**
Simple Payback Period	**9.6 yrs**

RPU COMMUNITY BENEFITS	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	15-YR TOTAL
Environmental Value																
Value from Reduced AMR Emissions (Mandatory)	$ 67	$ 178	$ 311	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 5,889
Value from Reduced Outage Response Emissions (Mandatory)	$ 6	$ 13	$ 21	$ 30	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 432
Value from Reduced Generation Emissions (Mandatory)	$ 43,092	$ 106,347	$ 184,551	$ 255,880	$ 294,202	$ 310,542	$ 327,583	$ 345,399	$ 363,988	$ 383,386	$ 388,305	$ 393,328	$ 398,457	$ 403,680	$ 409,013	$ 4,607,754
Service Value																
Enhanced Residential Service Value from Reduced Outage Time (Mandatory)	$ 1,422	$ 3,267	$ 5,335	$ 7,424	$ 8,290	$ 8,331	$ 8,373	$ 8,415	$ 8,457	$ 8,499	$ 8,542	$ 8,585	$ 8,627	$ 8,671	$ 8,714	$ 110,953
Enhanced Small C&I Service Value from Reduced Outage Time (Mandatory)	$ 53,786	$ 123,540	$ 201,776	$ 280,800	$ 313,575	$ 315,150	$ 316,725	$ 318,300	$ 319,875	$ 321,450	$ 323,025	$ 324,675	$ 326,325	$ 327,975	$ 329,625	$ 4,196,603
Enhanced Large C&I Service Value from Reduced Outage Time (Mandatory)	$ 49,749	$ 114,264	$ 186,576	$ 259,578	$ 289,800	$ 291,180	$ 292,560	$ 293,940	$ 295,320	$ 296,700	$ 298,080	$ 299,460	$ 300,840	$ 302,220	$ 303,600	$ 3,873,867
Total Community Benefits	**$ 148,122**	**$ 347,609**	**$ 578,571**	**$ 804,156**	**$ 906,345**	**$ 925,681**	**$ 945,718**	**$ 966,531**	**$ 988,118**	**$ 1,010,513**	**$ 1,018,430**	**$ 1,026,525**	**$ 1,034,727**	**$ 1,043,023**	**$ 1,051,429**	**$ 12,795,497**
Net Cost/Benefit	**$ (3,293,493)**	**$ (4,030,569)**	**$ (2,807,740)**	**$ (1,908,586)**	**$ 2,277,703**	**$ 3,350,387**	**$ 3,535,820**	**$ 3,732,915**	**$ 3,942,131**	**$ 4,164,239**	**$ 4,273,982**	**$ 4,387,438**	**$ 4,504,672**	**$ 4,625,686**	**$ 4,750,759**	**$ 31,505,343**
Cumulative Net Cost/Benefit	**$ (3,293,493)**	**$ (7,324,062)**	**$ (10,131,802)**	**$ (12,040,388)**	**$ (9,762,686)**	**$ (6,412,298)**	**$ (2,876,478)**	**$ 856,437**	**$ 4,798,568**	**$ 8,962,806**	**$ 13,236,788**	**$ 17,624,226**	**$ 22,128,898**	**$ 26,754,584**	**$ 31,505,343**	

IRR ($)	**18.6%**
NPV (2011$)	**$ 16,365,362**
Simple Payback Period	**7.8 yrs**

APPENDIX D

SELECT VENDOR INFORMATION SHEETS

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