Smart Grid Business Case and Technology Roadmap for

Shakopee Public Utilities

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Table of Contents

INTRODUCTION

Shakopee Public Utilities (SPU) currently provides, with its 47 employees, economical and reliable service to both electric and water customers within its jurisdiction through conventional metering technology. Their service territory measures about 40 square miles in and around the City of Shakopee, Minnesota.

Previously, SPU had created a Smart Grid Investment Grant (SGIG) application for installation of smart meters and deployment of other energy saving initiatives such as Home Area Networks (HAN) and Time-of-Use (TOU) rates. In creating the grant application, they used a template provided by Elster, but were unsuccessful in receiving a grant award. Elster is currently SPU's meter supplier.

RW Beck was contracted to provide a roadmap, which included a five-year plan. While providing a certain level of value to SPU, this plan did not contain specific recommendations or sufficiently detail Smart Grid implementation plans. RW Beck also conducted a Smart Grid workshop with the Commission. However, these actions did not lead to establishing a clear leadership direction of this effort at the Commission level related to the Smart Grid investment options for SPU.

Nonetheless, interest in the Smart Grid continued at SPU, with department heads developing a summary of what they believed was needed to implement a Smart Grid and the benefits that might be achieved. It was generally agreed that implementation would need to be a "turnkey project", as the existing staff was focused on the day-to-day operations of the electric and water utility business.

SPU has already moved forward on some aspects of the Smart Grid, which is reflected in their Demand Side Management (DSM) programs. SPU has considered a third party service for informing their electric customers on a quarterly basis of their energy consumption relative to comparable customers. This provides a cost effective means of promoting energy conservation.

There are many aspects of a Smart Grid that can and should be considered when developing a Smart Grid Business Case and Technology Roadmap. Typically, utilities begin by creating a Smart Grid Strategy, but in the process they soon realize they possess insufficient information or knowledge of opportunities that may exist in the evolving Smart Grid marketplace that would enable them to actually develop a workable Smart Grid Strategy. The Smart Grid strategy is then put on hold until a solid Smart Grid Business Case and Technology Roadmap can be developed.

By commissioning this Smart Grid Business Case and Technology Roadmap, SPU has now embarked upon development of the foundation for which financial and operational decisions can knowledgeably be ascertained. As part of the decision process, SPU should consider additional funding outside agencies such as Minnesota Municipal Utilities Association (MMUA). The information provided in this study by West Monroe Partners, LLC, in conjunction with the SPU staff, is specifically designed for the most cost effective development of the SPU Smart Grid over the next 15 years.

STUDY OBJECTIVES

On March 7, 2011, West Monroe Partners provided the Shakopee Public Utilities Commission (SPUC) with a Smart Grid Business Case Analysis presentation.

The content of the presentation addressed the following SPU objectives for initiating this study:

- Identify the benefits and costs associated with fifteen Smart Grid elements;
- Identify an economical combination of Smart Grid elements that meets the Client's needs and resources; and,
- Identify an efficient implementation roadmap that outlines the start and completion dates for the selected Smart Grid elements.

Discussion after the presentation to the Commission focused on the cost benefit of SPUC having this type of business case analysis done by a consulting firm. Funding issues were discussed and explained by Staff. In the end, the Commission agreed this to be an important step in the potential deployment of Smart Grid technologies.

A motion was made by Commissioner Helkamp, seconded by Commissioner McGowan, to fund the WMP proposal as presented and to execute the contract as presented. Motion carried.

As a result of this motion, this study was commissioned. The objectives that SPU has identified will be met through completion of this Smart Grid Business Case and Technology Roadmap.

EXECUTIVE SUMMARY

This Study was pursued to determine if it was cost effective to rollout a Smart Grid at SPU. Furthermore, a Technology Roadmap was to be developed that sequenced installation or implementation of the Smart Grid Elements most efficiently over time.

In conducting the Study it was found that a positive net present value of approximately $1.9 million can be achieved through construction of a Smart Grid at SPU. Detailed costs and benefits are provided within this Study. In brief, when accounting for interest and depreciation, the total project cost of $30.7 million will be incurred. There are $21.1 million in capital costs and an increase of $9.6 million in Operations and Maintenance costs over 15 years.

These capital and O&M costs are offset by benefits in three areas. Operational benefits are $13.0 million and the combined Energy and Demand Savings is $22.8 million. These are the "hard" benefits that come back to SPU's financial bottom line. There are also "soft" or societal benefits amounting to $7.7 million. These are derived from: (1) increased customer reliability; (2) decreased greenhouse gases; and, (3) customer energy savings by driving PHEV/EV vehicles versus traditional gasoline vehicles.

The proposed rollout plan essentially provides for the following steps to occur.

Year 1

- Organize the project and the program management team
- Confirm a rollout schedule
- Develop the required RFPs
- Begin mid-Year 1 with Smart Meter installations (both electric and water – install 20% of total)
- Install the core telecommunication system
- Install the Advanced Metering Infrastructure
- Install the Meter Data Management System
- Begin exploring Direct Voltage Control (25% of distribution system)
- Customer education programs

Year 2

- Install another 40% of the Smart Meters (both electric and water)
- Install the Load Control Management System
- Implement a portion of the DSM programs, including:
    - Prepay
    - Thermal Storage
    - Load Control Program for poly phase customers
    - ePortal
    - Time-of-Use Rate
- Complete Direct Voltage Control (75% of distribution system)

- Install initial Distribution Automation and Substation Automation equipment (10%)
- Expand use of Geographic Information System (25%)

Year 3

- Install the remaining 40% of the Smart Meters (both electric and water)
- Implement more of the DSM programs, including:
  - Home Energy Displays (75%)
  - Programmable Controlled Thermostats (75%)
  - Load Controlled Water Heaters (75%)
  - Load Controlled Air Conditioners (75%)
- Install first part of the Conservation Voltage Reduction program (50%)
- Continue to deploy Distribution Automation and Substation Automation equipment (10%)
- Continue to deploy Geographic Information System (15%)

Year 4

- Implement remaining portion of the DSM programs, including:
  - Home Energy Displays (25%)
  - Programmable Controlled Thermostats (25%)
  - Load Controlled Water Heaters (25%)
  - Load Controlled Air Conditioners (25%)
- Initiate Electric Vehicle (EV/PHEV) program (25%)
- Install remaining portion of the Conservation Voltage Reduction program (50%)
- Continue to deploy Distribution Automation and Substation Automation equipment (10%)
- Install an Outage Management System
- Continue to deploy Geographic Information System (15%)

Year 5 and Beyond

- Complete Electric Vehicle program over Years 5-7
- Complete the Distribution Automation and Substation Automation as needed over Years 5-15
- Complete the Geographic Information System over Years 5-7

The recommended Advanced Metering Infrastructure (AMI) and its associated core technology are discussed in detail within this Study; including the pros and cons of the differing technologies that are commonly used for Internet Protocol (IP) Backbone, Mid-Tier Backhaul, and Advanced Meter Infrastructure (AMI) communications. For the Smart Grid deployment it is recommended that SPU use an Unlicensed Point-to-Point Microwave IP Backhaul solution. Further, SPU should deploy a point to Multi-Point Solution for the Mid-Tier Backhaul.

And, finally, for the AMI, while both the Licensed Tower AMI solution and the Wireless Mesh AMI solution will work very well; due to the higher power output of the licensed solution meters, greater range, licensed spectrum and lower maintenance of the Licensed Tower equipment, WMP recommends the Licensed Tower solution to meet the requirements of SPU at an overall lower cost of ownership.

Smart Grid Elements that were excluded include any costs for upgrading the existing CIS application, implementing an Enterprise Asset Management System, a Distribution Management System, and a Mobile Workforce Management System. The benefits derived from these could not be quantified and they were not required for other applications to better achieve their benefits.

For all the recommended applications within this Study, the technology is sufficiently stable, with existing Standards in place, to deploy.

While this Study was extensive and it contains valid data on which to base both strategic and tactical decisions, it remains a snapshot in time. Moving toward a full Smart Grid implementation at SPU is economically feasible and practical. Additional assistance will be required to effectively implement on the proposed timeline, but such resources are available.

STUDY METHODOLOGY

West Monroe Partners, LLC employed a series of steps to not only gather information, but to share knowledge of Smart Grid implementation at SPU. The information gathering began with collecting statistics about SPU prior to arriving on-site. This information allowed WMP to tailor the initial Smart Grid Workshop for SPU's specific needs and concerns. When on-site, time could be spent more efficiently by first clarifying the information if necessary, but more importantly, discussing the implications of the current position of SPU in respect to the overall Smart Grid development in the United States.

The Smart Grid Workshop served to establish a vision of what Smart Grid consisted of and what Smart Grid Elements were most likely to be of value to SPU, which served to also establish expectations for future deliverables.

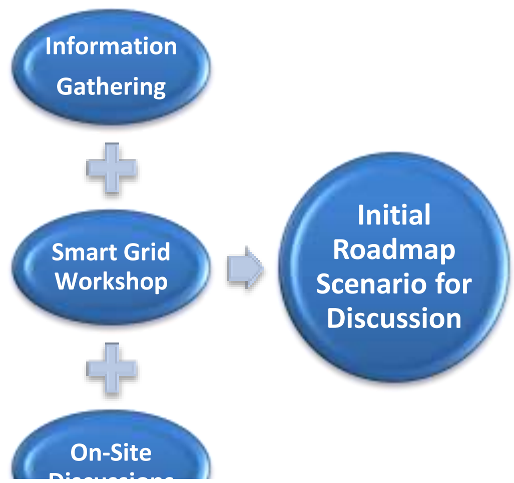


Figure 1 - Information Gathering and Sharing Process

Data Collection – Process Discussions

Upon collection on the statistics, subsequent on-site discussions were held over the course of several days. These series of on-site meetings, and the purpose for these meetings, are shown in the table below. These meetings were in-depth discussions allowing for a fluid exchange of information between WMP consultants and SPU staff. They served to inform SPU leadership of the potential opportunities existing for a utility of their size and customer characteristics.

While each of the sessions had a general focus and theme, participants were allowed to freely drive the discussion in the direction that best served their needs and concerns. In this manner, a rapport was established to allow for efficient and effective dissemination and transfer of knowledge.

Table 1 - On-site Discussions and Information Gathering Sessions

Meeting	Discussion Purpose
Kick-Off Meeting	Introduction to the process and purpose for the subsequent sessions. Include a discussion of the Smart Grid Elements.
Smart Grid Vision	Determine how SPU views the Smart Grid and the history of actions surrounding the Smart Grid. Additional discussion surrounded organizational structure, resources and resource constraints.
Electric Utility Meeting / Meter Data Management System (MDMS)	Discussed potential revenue increases through more accurate meters would be a benefit. Reduction of Labor due to reduction of meter readers. Reduction of vehicle costs due to less truck rolls for customers (*On-Demand Reads, Turn-on/Turn-off, customer no trouble found*). Discussed the requirements of a MDMS and associated costs and benefits.

Meeting	Discussion Purpose
Water Utility Meeting	Understand information about the SPU water utility such as operations, cost of operations, current conservation programs, and leak detection procedures. Also, the benefits of automated meter reading were discussed.
Finance, Accounting, Call Center, and Information Systems	Determine methods of financing at SPU and financing options. Call Center size and metrics were discussed. Other financial issues relative to operations and energy procurement contracts allowed for assessing future opportunities.
Demand Side Management (DSM) and Load Control Management Systems (LCMS)	Focus was on DSM opportunities at SPU including ePortal installation, the impact of Plug-In Hybrid Electric Vehicles (PHEV) /Electric Vehicles (EV) for SPU customers, and potential new rates such as Time-of-Use (TOU) or Critical Peak Pricing (CPP). The use of a Load Control Management System (LCMS) was also discussed.
Enterprise Asset Management (EAM)	This served as an introduction to Enterprise Asset Management (EAM) at SPU. It is a method of managing assets and major capital property units over the entire life-cycle of the asset, from procurement to retirement.
Distribution and Substation Automation (DA / SA)	DA and SA implementation provides improved equipment utilization and remote controlled operation of devices in substations and on the distribution feeders. The current SCADA functionality was discussed, including substation regulation equipment at SPU and operation of regulators and capacitor banks on the feeders and if they were controlled remotely. Potential energy and demand savings were identified.
Direct Voltage Control (DVC) / Conservation Voltage Reduction (CVR)	This was an introduction to DVC and CVR and Distribution Feed Optimization. It included discussion of DVC, a manual procedure for lowering system voltage during peak conditions. Future CVR requirements were gathered.
System Integration	This meeting focused on the pros / cons surrounding point-to-point integrations between systems versus the use of an Enterprise Service Bus (ESB).
Advanced Metering Infrastructure (AMI) / Core Telecommunications	This was an introduction to Advanced Metering Infrastructure (AMI) and Core Telecommunications. WMP gathered network and territory diagrams and size as well as discussed the security controls in place surrounding the network. Any known bandwidth requirements were discussed. Preferences were gathered for potential AMI systems and the need for an MDMS.
Outage Management System (OMS) and Distribution Management System (DMS)	This was an introduction to OMS and DMS. The current outage detection and mitigation methodology was discussed. Outage rates were gathered.

Meeting	Discussion Purpose
Geographic Information System (GIS)	GIS attributes were discussed and how they are collected at SPU. There was a discussion on how the water and electric (overhead and underground) utilities utilized GIS and how it integrated to other applications. The number of licenses and other GIS uses were discussed.
Power Production Contracts	This meeting gathered potential locations and methods for increased revenue to be captured. A consensus on Benefits of Conservation Voltage Reduction (CVR) (~2.5% on energy savings and ~3.5% on Demand savings. Information was gathered to construct a model of the power supply costs.

Initial Findings for Discussion

AMI and Core Telecommunication Findings

After examining information gathered at the SPU offices, the WMP consultants were back on-site for a one-day feedback session. Prior to arriving, an in-depth review was undertaken by the WMP consultants to identify a telecommunication infrastructure that would best serve the needs of SPU. This was presented to the SPU leadership team during the second on-site meeting and it is included in the AMI and Core Telecommunication section of this Study.

Power Procurement Opportunity Findings

The WMP consultants also reviewed the power procurement contract to determine the potential for leveraging the existing contract through Smart Grid technologies, including Demand Side Management Programs (DSM). SPU's will work closely with MMPA (Minnesota Municipal Power Agency) related to determining the DSM programs to ensure successful results for both parties and to ensure that the existing contract is not violated.

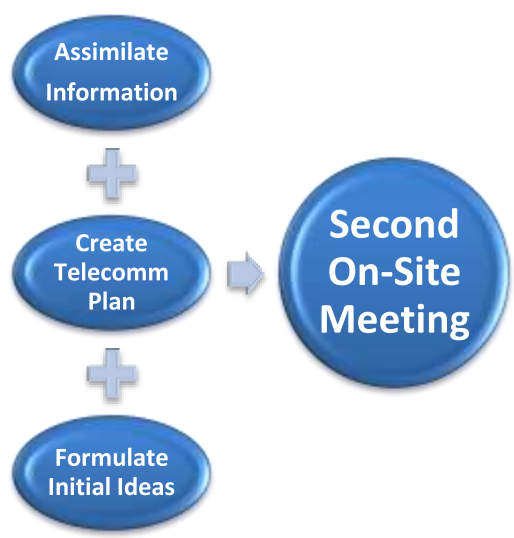


Figure 2 - Feedback and Roadmap Create Session

A demand (kW) rebate was identified within the power procurement contract. If the summer peak demand can be reduced and the winter demand increased overtime, it may be possible to realize a winter demand level that is over 80% of the previous summer peak. Any amount of winter demand over 80% of the previous summer peak will result in a $4.10 per kW credit applied to the winter demand cost.

The figure below illustrates the potential for savings. The previous summer peak was 93 MW. So, 80% of that amount is 74.4 MW. If during any of the seven months from October through April, demand levels exceed 74.4 MW, that amount over 74.4 MW will be credited $4.10 per kW; or $4,100 per MW.

While unattainable at this point in time, if the demand for each month of the year were to be a flat 93 MW, a maximum annual credit could be achieved of over $530,000 (20% x 93 MW x $4,100/MW x 7 months = $533,820).

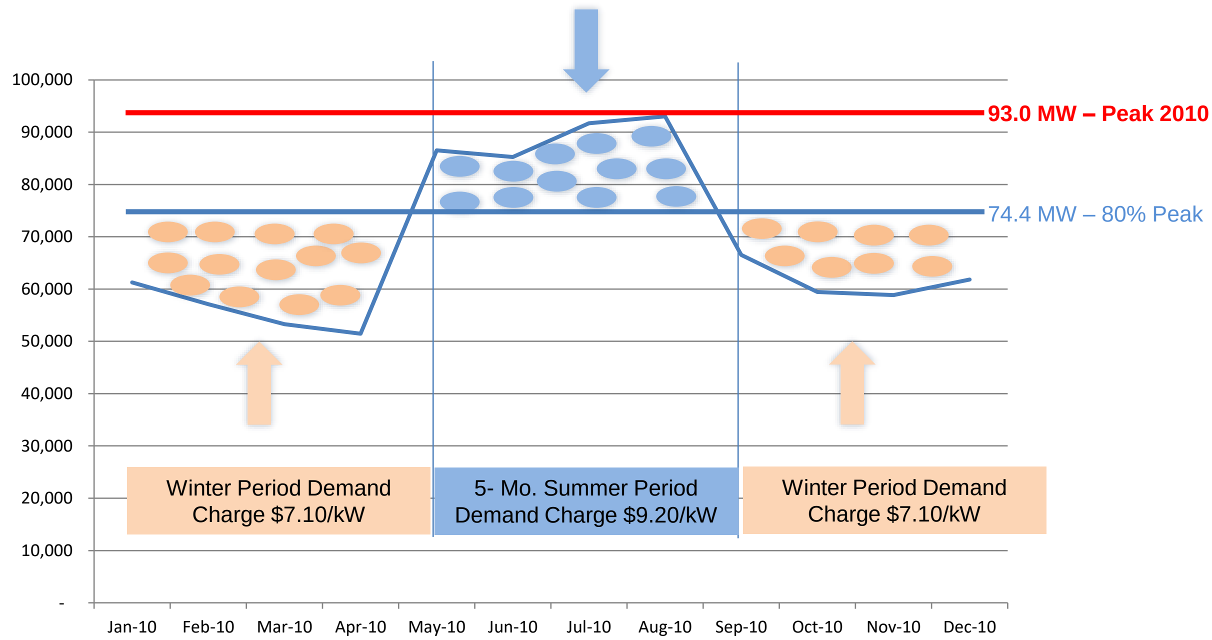


Figure 3 - SPU's 2010 Annual Demand Curve Illustrating Potential for Winter Period Credit

Additionally, there is a significant energy purchase price difference between the off-peak rates ($0.0308/$0.0383) and on-peak rate ($0.0552). The energy sales on Saturday, Sunday, and Holidays have the greatest consumption variation over the year – nearly doubling. The demand credit savings were not included in the Business Case cost / benefit analysis but is important enough to discuss in this document.

DSM Program Discussion

The question posed to the group was, "When considering all of the DSM Programs, are there many "must haves" regardless of cost – otherwise, WMP will select and recommend relevant DSM Programs to fit SPU Purchase Power Contract and Load Demand Curve." The consensus was to include all DSM Programs known at this time and WMP will evaluate them based upon associated costs and benefits, rather than force any single program. Nothing was excluded from consideration.

Scenario Definitions

There were three scenarios agreed upon to be modeled. The scenarios varied by the length of time smart meters were installed. Scenarios modeled a one-year rollout, a three-year rollout and a five-year rollout.

The SPU preferred solution was a three-year smart meter rollout period. This preferred scenario, upon being selected, was examined through the remaining in-depth analysis of this report. The following is a more detailed description of each of the three scenarios. As one might imagine, the smart meter rollout impacts the timeframe in which various other Smart Grid Elements are installed. The figure below illustrates the phased rollout process.

The Advanced Metering Infrastructure (AMI) and how it relates to the associated Core Telecommunication method are defined based upon the needs of SPU, including the amount of data and the latency of information transmission. Cost is a factor and needed to be used in weighing the most functionality at a reasonable cost to SPU. The DSM Programs followed. As mentioned earlier, all were left within the study for examination.

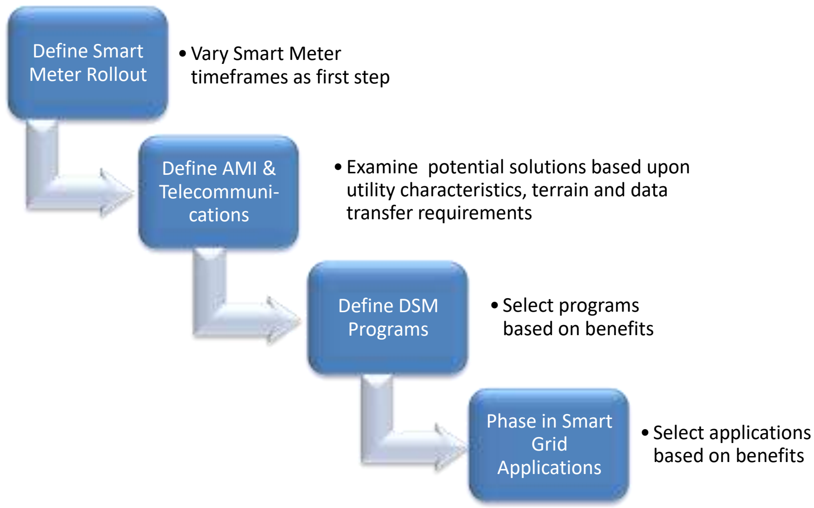


Figure 4 - Steps for Creating a Technology Roadmap

Finally, the actual Smart Grid related software applications were also placed on the Technology Roadmap based upon the earliest time they might be implemented. In general, most Smart Grid elements must be phased in with, or after, the Smart Meters are installed. While they function under the old way of doing business, they cannot provide additional benefits until the data is captured and housed in the MDMS.

A short description is provided of each Smart Meter timeframe. The recommended scenario is a three-year Smart Meter rollout. All of the financials are based on such a Smart Grid Technology Roadmap.

Scenario #1 – Using contract or turnkey installation: One-year meter installation and second year DSM program creation – fastest plan

The first scenario is to install the electric and water meters as soon as possible, which is the first year. The meter installation would need to be outsourced to get this accomplished in this timeframe. Then, in the second year, all of the Demand Side Management Programs are implemented to secure benefits as soon as possible.

Scenario #2 – Use internal resources: Three-year meter installation and second and third year DSM program creation – Mid Speed plan

This scenario is the preferred electric and water Smart Meter rollout timeframe. It is staged to allow for 20% of the Smart Meters to be installed in the first year and 40% in each consecutive year. The lower amount of meter installations in the first year provides time to create the necessary Request for Proposals for Smart Grid Elements selected by SPU. The meter installation would be accomplished solely with SPU internal employees. The infrastructure would be installed during the first year as well.

Scenario #3 – Using internal resources: Five-year meter installation and second, third and fourth year DSM program creation – Slowest plan

This scenario use only internal resources to replace electric and water meters over five years. It was assumed that no meter reading costs would be reduced during the first year, as all would continue to be needed to read those meters not changed out. The meter installation would be accomplished solely with SPU internal employees. The infrastructure would be installed during the first year as well.

The table below compares the three Scenarios. In general, due to the benefits that can be achieved through putting in the Smart Meters, DSM and other applications earlier (i.e., under Scenario #1), the NPV is a bit higher. Such benefits rise faster, offsetting the increased O&M costs by a small margin during those early years.

SCENARIO COMPARISION

SUMMARY #1: CAPITAL

Category	1 Year SM Implementation Years 1 - 15	3 Year SM Implementation Years 1 - 15	5 Year SM Implementation Years 1 - 15
Capital Cost	$ 16,564,156	$ 17,087,497	$ 17,160,622
O&M Costs	$ 10,225,087	$ 9,618,850	$ 9,618,011
Total Costs	$ 26,789,243	$ 26,706,347	$ 26,778,633
Operational Benefits	$ 14,004,145	$ 13,006,373	$ 11,962,192
Energy / Demand Benefits	$ 22,877,557	$ 22,852,561	$ 22,506,621
Total Hard Benefits	$ 36,881,702	$ 35,858,934	$ 34,468,813
Net Hard (Costs) / Benefits	$ 10,092,459	$ 9,152,587	$ 7,690,180
Net Present Value (NPV)	$ 2,457,522	$ 1,813,355	$ 611,776
Societal Benefits	$ 7,917,171	$ 7,600,594	$ 7,455,073
Total Soft Benefits	$ 7,917,171	$ 7,600,594	$ 7,455,073
Net Hard and Soft (Cost) / Benefits	$ 18,009,630	$ 16,753,181	$ 15,145,253
Net Present Value (NPV)	$ 7,523,208	$ 6,615,897	$ 5,267,619

SUMMARY #2: FINANCING (PRINCIPLE & INTEREST)

Category	1 Year SM Implementation Years 1 - 15	3 Year SM Implementation Years 1 - 15	5 Year SM Implementation Years 1 - 15
Capital Cost	$ 20,297,664	$ 20,473,258	$ 20,423,546
O&M Costs	$ 10,225,087	$ 9,618,850	$ 9,618,011
Total Costs	$ 30,522,751	$ 30,092,108	$ 30,041,557
Operational Benefits	$ 14,004,145	$ 13,006,373	$ 11,962,192
Energy / Demand Benefits	$ 22,877,557	$ 22,852,561	$ 22,506,621
Total Hard Benefits	$ 36,881,702	$ 35,858,934	$ 34,468,813
Net Hard (Costs) / Benefits	$ 6,358,951	$ 5,766,826	$ 4,427,256
Net Present Value (NPV)	$ 3,012,291	$ 2,634,134	$ 1,499,528
Societal Benefits	$ 7,917,171	$ 7,600,594	$ 7,455,073
Total Soft Benefits	$ 7,917,171	$ 7,600,594	$ 7,455,073
Net Hard and Soft (Cost) / Benefits	$ 14,276,122	$ 13,367,420	$ 11,882,329
Net Present Value (NPV)	$ 8,077,977	$ 7,436,677	$ 6,155,372

SUMMARY #3: FINANCING (DEPRECIATION & INTEREST)

Category	1 Year SM Implementation Years 1 - 15	3 Year SM Implementation Years 1 - 15	5 Year SM Implementation Years 1 - 15
Capital Cost	$ 20,807,254	$ 21,088,378	$ 21,082,479
O&M Costs	$ 10,225,087	$ 9,618,850	$ 9,618,011
Total Costs	$ 31,032,341	$ 30,707,228	$ 30,700,490
Operational Benefits	$ 14,004,145	$ 13,006,373	$ 11,962,192
Energy / Demand Benefits	$ 22,877,557	$ 22,852,561	$ 22,506,621
Total Hard Benefits	$ 36,881,702	$ 35,858,934	$ 34,468,813
Net Hard (Costs) / Benefits	$ 5,849,361	$ 5,151,706	$ 3,768,323
Net Present Value (NPV)	$ 2,372,455	$ 1,940,485	$ 782,471
Societal Benefits	$ 7,917,171	$ 7,600,594	$ 7,455,073
Total Soft Benefits	$ 7,917,171	$ 7,600,594	$ 7,455,073
Net Hard and Soft (Cost) / Benefits	$ 13,766,532	$ 12,752,300	$ 11,223,396
Net Present Value (NPV)	$ 7,438,140	$ 6,743,027	$ 5,438,315

Figure 5 - Scenario Comparison

Areas Benefits May Be Achieved

Operational Savings

Operational benefits are measured by the savings from the utility capital and operational budgets. These benefits should result in reductions of the utility capital or expense budgets. These benefits impact the utility directly and may change not only the financial bottom line, but also the business practices. SPU should be aware of the potential need to review current business processes and consider undertaking Business Process Optimization techniques as required.

Energy and Demand Reduction Benefits from DVC/CVR

Energy and demand reduction benefits from DVC/CVR result in lower energy and demand that the utility needs to generate and/or purchase to serve their distribution customers. Typically, the benefit is derived from an optimized distribution network, rather than a change in customer behavior or direct control of customer loads. The source of these benefits is related to increased system efficiency through optimizing Voltage/VARS during on-peak and off-peak periods, as new equipment and conductors with lower losses are utilized. These benefits occur both before and after the meter. This means that some of these benefits are realized by the utility without impacting the customer's bill and some of these benefits are realized by the customer seeing a lower electric bill. It is important to quantify these benefits and if the customer benefits are large enough the utility may need to consider a new cost of service study to determine if they are collecting enough revenue to cover their distribution costs with the decrease in energy and demand due to the DVC/CVR efforts.

Energy and Demand Benefits from DSM Programs

Energy and demand benefits from DSM programs are measures by the decreased amount of energy and demand that the utility needs to generate and/or purchase to serve their distribution customers. Typically the benefit is derived from changes in customer behavior or direct control of customer loads. These benefits occur both before and after the meter. This means that some of these benefits are realized by the utility without significantly impacting the customer's bill and some of these benefits are realized by the customer with a lower electric bill. It is important to quantify these benefits and if the customer benefits are large enough the utility may need to consider a new cost of service study to determine if they are collecting enough revenue to cover their distribution costs with the decrease in energy and demand due to the DSM program efforts. It is also important to note that the utility needs to look at the relative benefits to the customer and utility for each program to determine what are the appropriate incentives that the utility needs to offer the customers to enroll in each of the DSM programs. The customer incentives are not built into the business case cost as they are currently unknown and need to be examined by SPU as each of the programs are created. Typically, increased incentives provide the increased penetration of the DSM program. This along with TOU rates needs to be taken into account in establishing each of the programs.

Societal Benefits

These benefits are more difficult to measure in hard dollars, but are realized almost entirely by the customer and society at large. WMP's methodology looks at three types of societal benefits in this Study: (1) increase customer reliability; (2) decreased greenhouse gases; and, (3) customer energy savings by driving PHEV/EV vehicles versus traditional gasoline vehicles. WMP used several studies authored by Electric Power Research Institute (EPRI) to translate decreases in greenhouse gases and reduced minutes of outage to dollar savings for a utility. The reduced cost of energy needed to drive a PHEV/EV versus a traditional gasoline vehicle does not take into account the difference in vehicle costs, the federal incentives available, or the difference in maintenance cost of the PHEV/EV versus gasoline vehicle.

RECOMMENDED SMART GRID PLAN AND ROADMAP OVERVIEW

The recommended Smart Grid Plan and Technology Roadmap are shown below. It represents a three-year meter rollout timeframe. This allows sufficient time for creation of the necessary RFPs and establishment of Vendor contracts.

3-YEAR METER SCENARIO
SMART GRID ROADMAP - IMPLEMENTATION BY YEAR (INPUT)

Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Total
Smart Meters - Electric (Residential)	20%	40%	40%													100%
Smart Meters - Electric (Single Phase C&I)	20%	40%	40%													100%
Smart Meters - Electric (Poly Phase C&I)	20%	40%	40%													100%
Smart Meters - Electric (Power Quality C&I)																0%
Smart Meters - Electric (Other C&I)																0%
Smart Meters - Water (Residential)	20%	40%	40%													100%
Smart Meters - Water (Commercial)	20%	40%	40%													100%
System Integration (SI)	40%	40%	10%	10%												100%
Meter Data Management System (MDMS)	100%															100%
Core Telecommunications	100%															100%
Advanced Metering Infrastructure (AMI)	100%															100%
Load Control Management System (LCMS)		100%														100%
DSM - Prepay (Residential)		100%														100%
DSM - Thermal Storage Program (Poly Phase C&I)		100%														100%
DSM - Load Control Relay (Poly Phase C&I)		100%														100%
DSM - ePortal (Residential, Single Phase C&I)		100%														100%
DSM - TOU (All customers)		100%														100%
DSM - HED (Residential, Single Phase C&I)			75%	25%												100%
DSM - PCT (Residential, Single Phase C&I)			75%	25%												100%
DSM - LCR - Water Heaters (Residential, Single Phase C&I)			75%	25%												100%
DSM - LCR - Air conditioners (Residential, Single Phase C&I)			75%	25%												100%
DSM - EV / PHEV (Residential)				25%	25%	25%	25%									100%
Customer Information System (CIS)																0%
Direct Voltage Control (DVC)	25%	75%														100%
Conservation Voltage Reduction (CVR)			50%	50%												100%
Distribution Automation (DA) / Substation Automation (SA)		10%	10%	10%	7%	7%	7%	7%	6%	6%	6%	6%	6%	6%	6%	100%
Enterprise Asset Management (EAM)																0%
Outage Management System (OMS)				100%												100%
Distribution Management System (DMS)																0%
Geographic Information System (GIS)		25%	15%	15%	15%	15%	15%									100%
Program Management	45%	40%	10%	5%												100%

Figure 6 - Recommended Smart Grid Technology Roadmap

The waterfall diagram below illustrates the financial impact to SPU over the course of the SPU Smart Grid development.

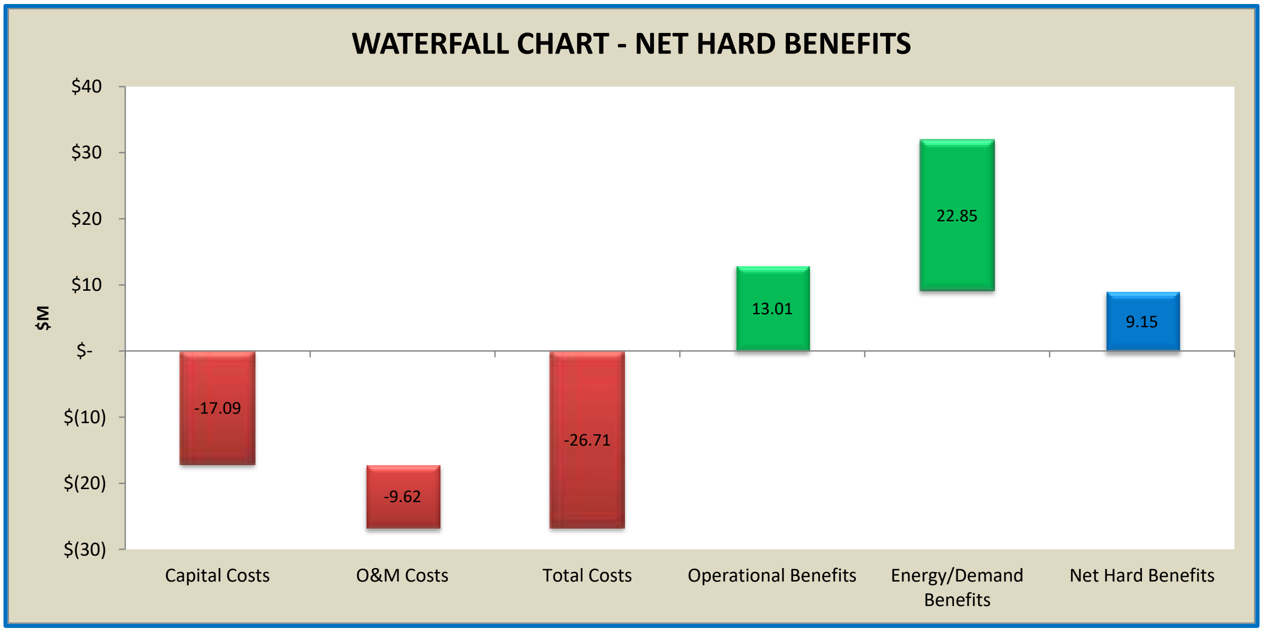


Figure 7 - Waterfall Chart (Net Hard Benefits)

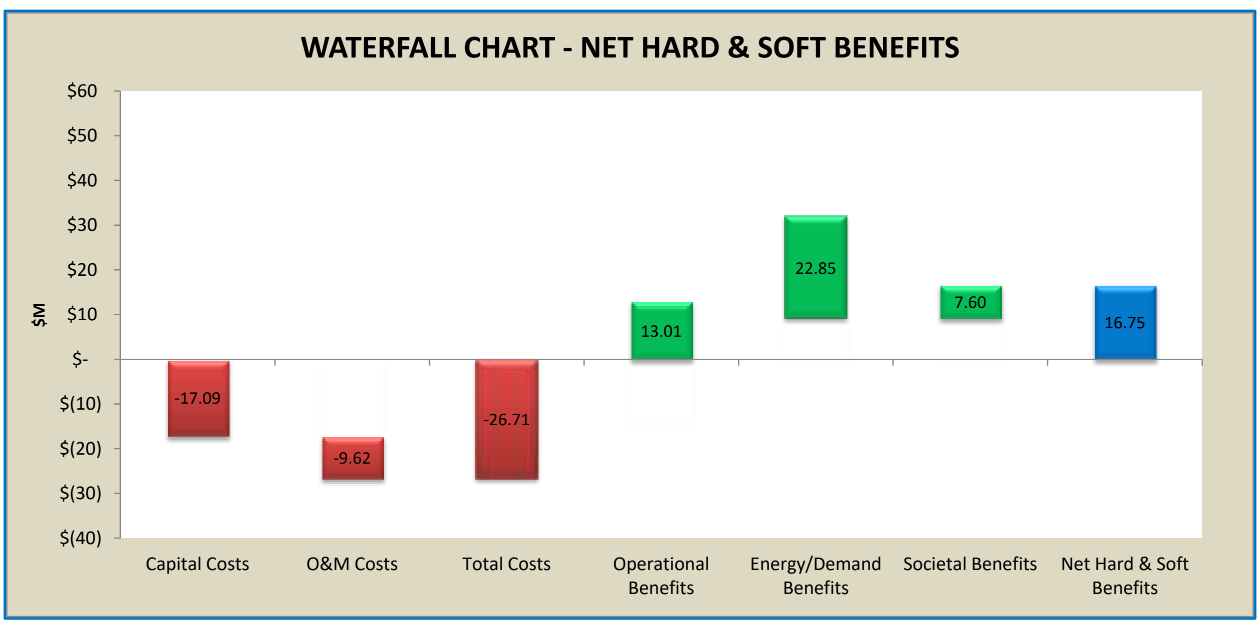


Figure 8 - Waterfall Chart (Net Hard and Soft Benefits)

Economic Analysis Methodology

The economic summary of the scenarios can be viewed in three different ways, depending upon how one considers the use of principle payment, depreciation and interest expense, the manner in which the debt is financed, and other variables. WMP has calculated the capital investment without respect to principle payment, interest and depreciation. This method reflects the amount of capital that will be required in any particular year. Such a presentation of the financials is useful when determining the annual financing requirements over the next 15 years for development of the Smart Grid at SPU. This financial representation provides SPU a "hard" net present value (NPV) of $1.81 million. The "hard benefits", which is sometimes referred to as "operational benefits", includes areas such as increase in revenue, decrease in salary and vehicle expenses, etc. The "hard" NPV excludes "soft" or what is sometimes referred to as "intangible" societal benefits. These benefits are significant and include such items as reduced carbon emissions from fewer trips to disconnect customers in arrears.

SUMMARY #1: CAPITAL

Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
Capital Costs	$ 6,249,971	$ 3,721,818	$ 2,820,440	$ 1,532,462	$ 405,871	$ 200,053	$ 17,087,497
O&M Costs	$ 203,472	$ 496,673	$ 604,872	$ 608,741	$ 617,708	$ 799,665	$ 9,618,850
Total Costs	$ 6,453,442	$ 4,218,491	$ 3,425,311	$ 2,141,203	$ 1,023,579	$ 999,718	$ 26,706,347
Operational Benefits	$ 112,699	$ 391,241	$ 641,348	$ 825,688	$ 850,609	$ 1,176,964	$ 13,006,373
Energy / Demand Benefits	$ 49,786	$ 220,982	$ 562,589	$ 953,995	$ 1,096,127	$ 2,932,048	$ 22,852,561
Net Hard (Costs) / Benefits	$ (6,290,958)	$ (3,606,268)	$ (2,221,374)	$ (361,520)	$ 923,156	$ 3,109,294	$ 9,152,588
Net Present Value (NPV)	$ 1,813,355						
Societal Benefits	$ 14,412	$ 93,291	$ 161,584	$ 282,325	$ 325,087	$ 1,211,311	$ 7,600,594
Total Soft Benefits	$ 14,412	$ 93,291	$ 161,584	$ 282,325	$ 325,087	$ 1,211,311	$ 7,600,594
Net Hard and Soft (Cost) / Benefit	$ (6,276,546)	$ (3,512,977)	$ (2,059,790)	$ (79,195)	$ 1,248,243	$ 4,320,604	$ 16,753,182
Net Present Value (NPV)	$ 6,615,897						

The second method of presenting the financial picture is to show the capital and impose on it the payment and interest costs, of which 4.50% has been chosen by SPU to be conservative. This financial picture is used for determining cash flow requirements, which can be compared to an amortized home mortgage payment. By representing the financial in this manner, the "hard" NPV is $2.63 million.

SUMMARY #2: FINANCING (PRINCIPLE & INTEREST)

Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
Capital Costs (Debt Service)	$ 581,959	$ 928,511	$ 1,191,133	$ 1,333,826	$ 1,371,619	$ 1,591,082	$ 20,473,258
O&M Costs	$ 203,472	$ 496,673	$ 604,872	$ 608,741	$ 617,708	$ 799,665	$ 9,618,850
Total Costs	$ 785,430	$ 1,425,184	$ 1,796,005	$ 1,942,567	$ 1,989,327	$ 2,390,747	$ 30,092,108
Operational Benefits	$ 112,699	$ 391,241	$ 641,348	$ 825,688	$ 850,609	$ 1,176,964	$ 13,006,373
Energy / Demand Benefits	$ 49,786	$ 220,982	$ 562,589	$ 953,995	$ 1,096,127	$ 2,932,048	$ 22,852,561
Net Hard (Costs) / Benefits	$ (622,946)	$ (812,961)	$ (592,068)	$ (162,885)	$ (42,591)	$ 1,718,265	$ 5,766,827
Net Present Value (NPV)	$ 2,634,134						
Societal Benefits	$ 14,412	$ 93,291	$ 161,584	$ 282,325	$ 325,087	$ 1,211,311	$ 7,600,594
Total Soft Benefits	$ 14,412	$ 93,291	$ 161,584	$ 282,325	$ 325,087	$ 1,211,311	$ 7,600,594
Net Hard and Soft (Cost) / Benefit	$ (608,534)	$ (719,670)	$ (430,484)	$ 119,441	$ 282,496	$ 2,929,575	$ 13,367,421
Net Present Value (NPV)	$ 7,436,677						

A third manner of examining the financials is to include interest of 4.50% and depreciation of 15 years for all capital which includes hardware, software and labor costs associated with the SG implementation. This financial view of the SPU Smart Grid Technology Roadmap provides a "hard" NPV of $1.94 million. This method of presenting the financial view is the estimated costs that will be recorded each year on the SPU financials.

SUMMARY #3: FINANCING (DEPRECIATION & INTEREST)							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
Capital Cost (Debt Service + Depreciation)	$ 697,913	$ 1,100,390	$ 1,393,772	$ 1,536,253	$ 1,548,510	$ 1,352,254	$ 21,088,378
O&M Costs	$ 203,472	$ 496,673	$ 604,872	$ 608,741	$ 617,708	$ 799,665	$ 9,618,850
Total Costs	$ 901,385	$ 1,597,063	$ 1,998,644	$ 2,144,994	$ 2,166,219	$ 2,151,919	$ 30,707,227
Operational Benefits	$ 112,699	$ 391,241	$ 641,348	$ 825,688	$ 850,609	$ 1,176,964	$ 13,006,373
Energy / Demand Benefits	$ 49,786	$ 220,982	$ 562,589	$ 953,995	$ 1,096,127	$ 2,932,048	$ 22,852,561
Total Hard Benefits	$ 162,485	$ 612,223	$ 1,203,937	$ 1,779,683	$ 1,946,736	$ 4,109,012	$ 35,858,935
Net Hard (Costs) / Benefits	$ (738,901)	$ (984,840)	$ (794,707)	$ (365,311)	$ (219,483)	$ 1,957,093	$ 5,151,707
Net Present Value (NPV)	$ 1,940,485						
Societal Benefits	$ 14,412	$ 93,291	$ 161,584	$ 282,325	$ 325,087	$ 1,211,311	$ 7,600,594
Total Soft Benefits	$ 14,412	$ 93,291	$ 161,584	$ 282,325	$ 325,087	$ 1,211,311	$ 7,600,594
Net Hard and Soft (Cost) / Benefits	$ (724,489)	$ (891,549)	$ (633,123)	$ (82,986)	$ 105,604	$ 3,168,403	$ 12,752,301
Net Present Value (NPV)	$ 6,743,027						

Interest Rate Impact

The impact of the cost of money was examined to determine the variance in NPV for financing (depreciation and interest) over a range of interest rates. This is shown in the table below. As interest rates increase, with all other things remaining the same, the NPV will decline.

Impact of Interest Rates	
Annual Interest Rates	NPV*
3.0%	$3,593,153
3.5%	$3,050,320
4.0%	$2,499,379
4.5%	$1,940,485
5.0%	$1,373,795
5.5%	$799,472
6.0%	$217,680
* Financing (Depreciation and Interest)	

Figure 9 - Impact of Interest Rates on Project NPV

While outside the scope of this Study, it is possible that Federal or State grants or low interest loans could be obtained for a portion of the required capital investments for Smart Grid development. Some of these may focus on educating the customers, promoting Demand Side Management programs, and even providing information to other municipal organizations.

RESOURCE REQUIREMENTS

In general, Smart Grid implementation involves increasing levels of technology within the utility and correspondingly increasing the knowledge and skill base of its employees. Current human resources will require additional training to perform new job responsibilities.

Information Technology

Currently there is one IT Coordinator who provides network administration, desktop installations, maintenance and installation of printers, and various technician responsibilities. The mainframe computer is an IBM AS/400 that has the Daffron & Associates, Inc. suite of applications operating on it. Daffron runs maintenance patches for an annual maintenance fee.

Call Center

There is one dispatcher in the main office, for dispatching trouble crews. The SPU Call Center is headed by a Marketing / Customer Relations Director.

- 2 Customer Service Representatives who take payments and field incoming calls
- 2 Billing Clerks
- 1 Customer Service Supervisor
- 1 Billing Clerk Supervisor
- 4 Meter Readers who work 90% of the time (36 hours per week)

SPU currently has an email address, so customers can contact them via emails. There is also an Internet website available, but it is not interactive.

SPU is currently considering upgrading their phone system. It does not allow for tracking or recording of incoming calls. Included in the business case, is $161,824 in costs to support the increased call volume of customers first being introduced to AMI. This is a short-term labor requirement, as call volume actually decreases over time on a per customer basis.

PROGRAM MANAGEMENT CONSIDERATIONS – MANAGING RISK

As a project this large is implemented, there are numerous project related management issues that require attention before, during and after the project is completed, including planning for on-going maintenance support. The proper project management level has been provided for in this Study.

PROGRAM MANAGEMENT (INPUTS)							
SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	INPUT	INPUT	INPUT	INPUT	FALSE	FALSE	
Capital Costs	$ 1,073,280	$ 763,766	$ 343,137	$ 237,515	$ -	$ -	$ 2,417,698
O&M Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Costs	$ 1,073,280	$ 763,766	$ 343,137	$ 237,515	$ -	$ -	$ 2,417,698
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Hard and Soft (Costs) / Benefits	$ (1,073,280)	$ (763,766)	$ (343,137)	$ (237,515)	$ -	$ -	$ (2,417,698)
Net Present Value (NPV)	$ (2,226,326)						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

The following functional issues are essential to overall project success and their costs have been estimated and included within the scope of this Study.

Program Management

To fulfill Project Management responsibilities, the Project Management Body of Knowledge (PMBOK) model for managing Projects is recommended. It's a collection of processes and knowledge areas generally accepted as best practice within the project management discipline.

As an internationally recognized standard (IEEE Standard 1490-2003) it provides the fundamentals of project management, irrespective of the type of project be it construction, software, engineering, automotive etc. PMBOK recognizes five basic process groups and nine knowledge areas typical of almost all projects. The basic concepts are applicable to projects, programs and operations. The five basic process groups are:

1. Initiating
2. Planning
3. Executing
4. Monitoring and Controlling
5. Closing

Managing and executing a successful project that spans across multiple departments and includes both internal and external stakeholders is a very challenging endeavor. With so many moving pieces, the project takes on a life of its own and can result in the project being delivered late, over budget, or both.

A Certified **Project Management Professionals (PMP)** specializes in managing these multi-faceted and multi-dimensional projects within the utility industry and in other industries as well.

Providing ongoing Project Management and resource mobilization support to make certain the Project progresses as expected is essential. The continued execution of proper Project Management approach and best practices minimizes Project risk and quickly resolves challenges before they become significant issues. A PMP will actively manage and assess the estimated time to completion for Project deliverables and milestones as well as Project trends to provide on-time and on budget Project delivery.

A PMP leading the projects increase the success rate of the projects across. The PMBOK is the international standard for Project Management practices and provides the framework for performing Project Management services. As shown in the figure below, Project Management is comprised of the following elements: Time Management, Resources Management, Risk & Issue Management, Scope & Change Management, Communications Management, Quality Management, Integration Management, and Cost Management.

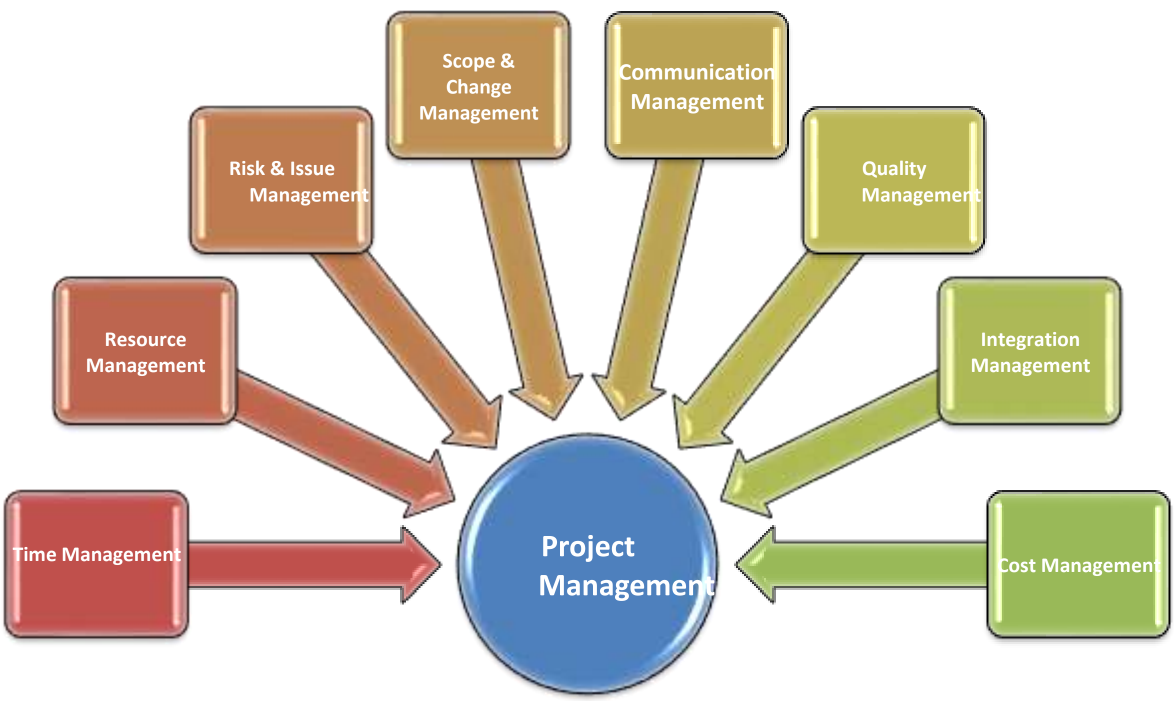


Figure 10 - Project Management Elements

Change Management

Change management is the process of making changes in a planned and managed, or systematic fashion. The goal is to more effectively implement new methods, systems, and designs in an organized, ongoing fashion. Any and all changes that occur within the change management system are audited and associated with an appropriate member of the organization.

- The number one success factor to implementing change management is strong sponsorship within an organization – leadership from the top, by example.
- The number one obstacle to successful change management is employee resistance.

One meaning of "managing change" refers to the making of changes in a planned and managed or systematic fashion. The aim is to more effectively implement new methods and systems in an ongoing organization. The changes to be managed lie within and are controlled by the utility. Perhaps the most familiar instance of this kind of change is the change or version control aspect of Information Technology development projects. However, these internal changes might have been triggered by events originating outside the organization, in what is usually termed "the environment." Hence, the second meaning of managing change, namely, the response to changes over which the utility exercises little or no control (e.g., legislation, social and political upheaval, the actions of competitors, shifting economic tides and currents, and so on). Researchers and practitioners alike typically distinguish between a knee-jerk or reactive response and an anticipative or proactive response.

Business Process Optimization (BPO)

A proven approach to business process optimization consists of several discrete steps:

Assess your current state. Assess and document all of the characteristics of and steps involved in your current process. Then, document constraints, gaps, and desired capabilities.

Eliminate waste. Analyze each aspect of the current process and ask critical questions to determine whether the element adds value or is necessary. Look at the numbers of people and hand-offs involved in the process and the amount of time required to complete the activity.

Re-design the process. Work with your team to re-design the process by removing unnecessary or redundant steps, automating steps within the process, and reducing the number of hand-offs.

Identify solutions. Work to identify and put in place the tools, systems, and people to support your new business processes.

Deploy the process. Train your team to measure and maintain new processes and to ensure a successful transition.

Throughout all elements of this approach, the overriding focus should be on guiding the creation of processes that sustain efficiencies and enable continuous improvement. This is done by considering issues such as:

- Scope and complexity of the redesign effort
- Impact on customer-facing activities
- Opportunities for quick wins versus longer-term benefits
- Management support and sponsorship for key changes
- Interdependencies among processes
- Risks associated with process change
- Other ongoing initiatives that may impact change

Quality Assurance (QA)

The purpose is to identify the quality standards that are relevant to the project and determine how to satisfy them. Most organizations have Quality Policies, Information Technology standards, and regulatory agency standards for compliance. True Quality Management involves not only testing and standards, but also whether the standards are being followed.

During the quality planning process, it is a critical success factor to review the Requirements Specification for the specific requirements for quality related to this development project. It may be also necessary to review the requirements for quality embedded in a Request for Procurement (RFP) or even add quality requirements to an outgoing RFP when managing a project that has a procurement component.

There are expenses associated with quality management activities. These were included in the project estimates of this Study; however, it is sometimes required, during the quality planning process, to redo the project cost/benefit analysis or feasibility study.

The Quality Assurance Plan is developed describing the process for managing project and product quality. This plan describes the major processes for ensuring project quality – project and product review process (project, client, team, and technical), the configuration management process (version control, promotion, and distribution), and the testing process. The process and goals for measurements must be either described or reference another document source such as the organization's Quality Manual. The benefits of this approach are that you will achieve: (1) A product that meets client/customer/project sponsor expectations; and, (2) A project work effort that is successful.

Capturing Additional Potential Benefits

There are several additional steps that SPU might consider to increase the NPV of their Smart Grid Technology Roadmap. The items mentioned above include: (1) obtain excellent project managers and use proven Project Management techniques; (2) manage the changes that will impact SPU from implementation of the Smart Grid Elements; (3) take the time to understand the business processes that will be changing at SPU as a result of newly acquired technology and information; and, (4) set up the quality standards and track progress against those pre-determined metrics.

The additional actions that can be taken include the following:

Creation of a Smart Grid Strategic Vision

SPU had previously begun work on creation of the SPU Smart Grid Strategic Vision. Yet, without sufficient information relative to opportunities and associated costs and benefits, full development of the Strategic Vision could not be achieved. With this Study, SPU does have the information to proceed on development of their Smart Grid Strategic Vision.

Creation of a Strategic Communication Plan

This Study presents a complete Smart Grid Technology Roadmap for SPU's implementation. It clearly defines what year various actions can be undertaken. This means that SPU knows when new applications, systems, and customer programs will impact the various stakeholders. A Strategic Communication Plan will identify all stakeholders who are impacted throughout the 15-year timeframe and, most importantly, determine how the stakeholders will be contacted and what message will be delivered to them.

Steps taken to properly communicate to stakeholders will mitigate possible issues or misunderstandings within the community. Proper communications also will aid in getting the community confortable with the change and allow them an opportunity to ask questions and raise concerns.

ELECTRIC ENERGY CONSUMPTION AND DEMAND FORECASTS

There are two components to the utilization of electricity, energy and demand. This is best understood by considering a light bulb. If it's a 100 watt bulb, it requires a "demand" of 100 watts to operate. If it operates for one hour it consumes 10 kilowatt-hour (kWh) of "energy". Hence, no matter how much one would use the bulb, the "demand" would never exceed 100 watts, but the energy consumption continues to rise with each hour of use.

The demand component of electricity is associated with the capital investment an energy provider commits to developing their generation stations and transmission infrastructure. This infrastructure is needed to meet the maximum demand of the customers served. On the other hand, the energy consumed by the customers is associated with the day-to-day operations and fuel costs of the energy provider. The energy that is consumed is directly related to the amount of fuel that must be purchased.

Hence, the most economical operating costs are achieved when the generation plant is running near capacity, meaning that the most energy is produced for the amount of capital invested. The ideal energy curve over time would be flat. This is rarely achieved, except in locations like Las Vegas, where the casinos are the largest customers and have a near continuous energy load. Their lights never get turned off!

As one might expect, SPU's energy consumption over the typical year is not a flat line. Instead, if one were to examine the 2010 annual energy consumption curve, it would appear as shown in the figure below. Sales were lowest in April at 29,398 MWH and highest in August at 44,768 MWH. Energy purchases ranging over this spectrum are not unusual for an electric utility. Higher demand tends to correlate with higher energy consumption, but not directly. In fact, when graphing these together, there's a correspondingly higher summer demand than one might expect.

Such information indicates opportunities may exist for either reducing or shifting summer demand to off-peak periods.

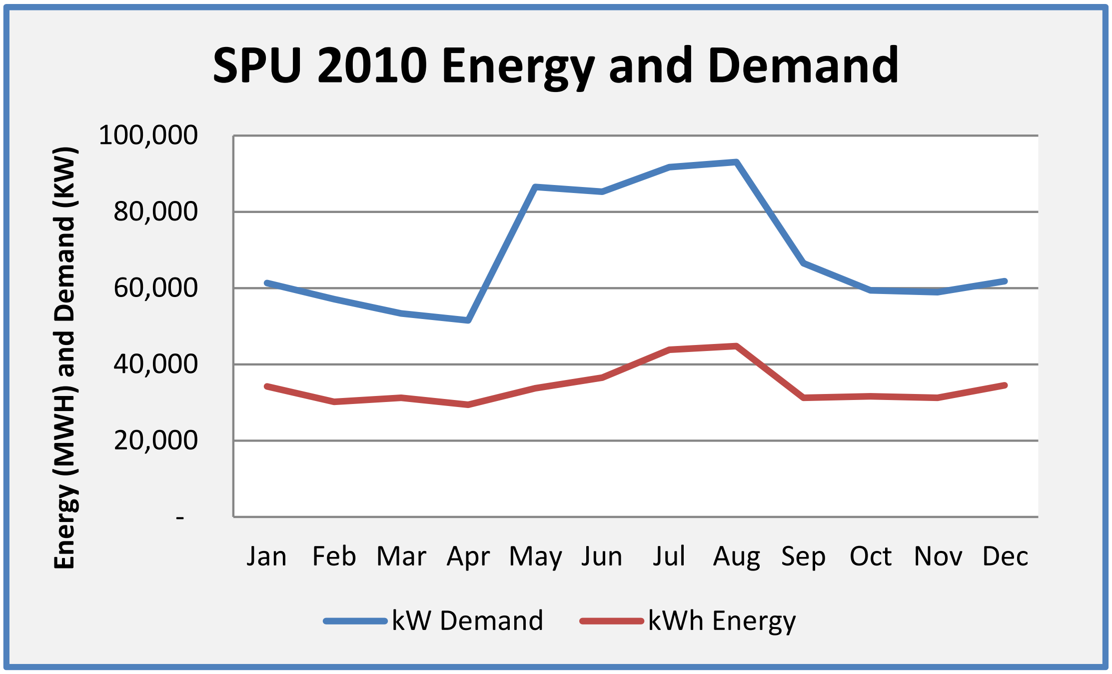


Figure 11 - SPU's 2010 Energy and Demand Curves by Month

The historical growth of energy and demand is another consideration. In plotting these over a 12-year period and using linear regression analysis to plot a "best-fit" curve, the following two graphs have been constructed. This figure may be atypical due to implementation of conservation programs as well as the worsening economy and cooler summer season than normal.

The historical energy growth at SPU has been 4.0% over the past 12 years, while historical demand growth over the same period has been 3.6%. This is positive, as it indicates SPU's load curve is improving; i.e., selling more energy for the same demand level.

Upon discussion with SPU staff, it was determined that a more conservative average demand and energy growth rate of 2.3% would be used for the purposes of this Study.

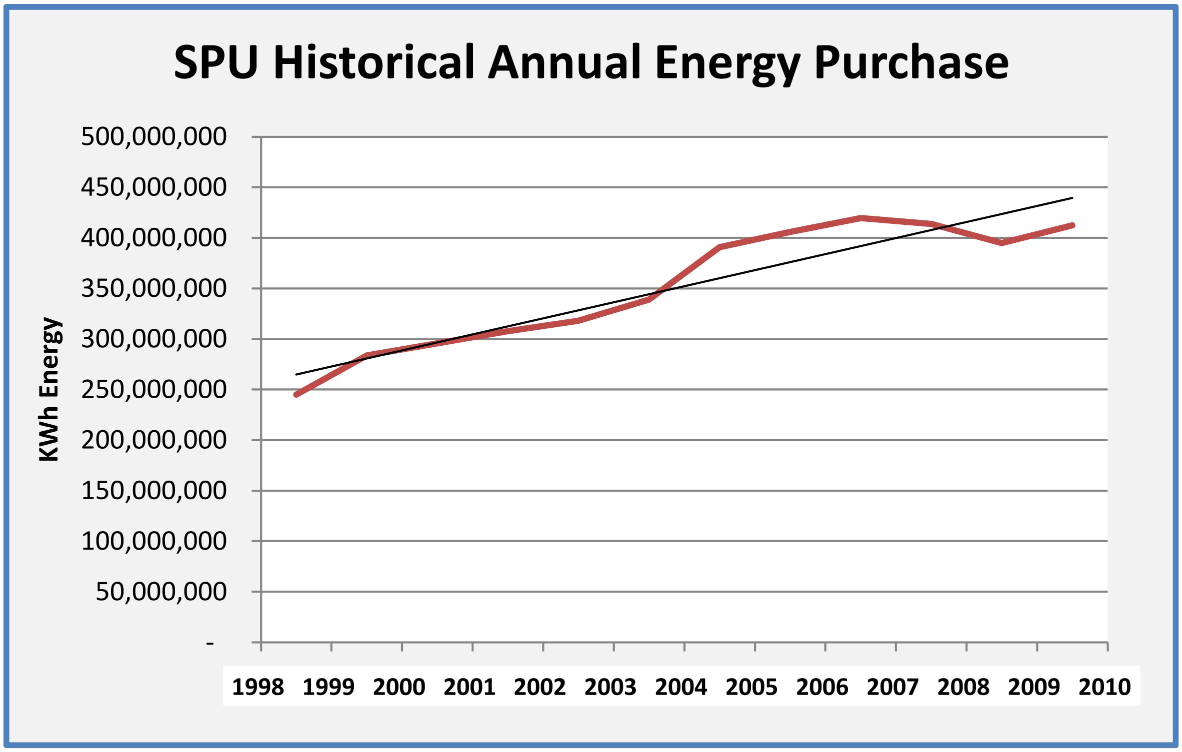


Figure 12 - SPU's Historical Energy Growth over 12 Years is 4.0%

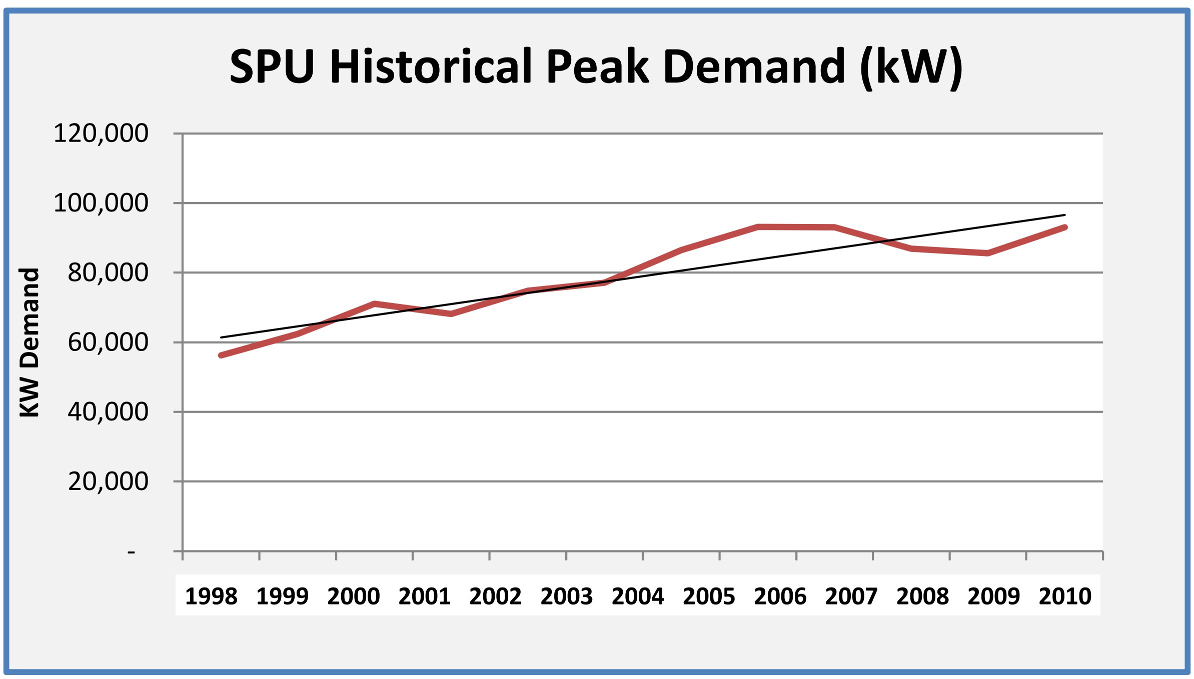


Figure 13 - SPU's Historical Demand Growth over 12 Years is 3.6%

POWER PROCUREMENT OPPORTUNITIES

SPU currently purchases electric energy from the Minnesota Municipal Power Agency (MMPA). The figure below shows the energy consumption of the SPU customers during the three timeframes defined by the existing power procurement contract. The left axis is in megawatt-hours over the year 2010.

The highest purchases were during the most costly time period, the Week Day On-Peak period. This presents an opportunity to SPU in the event DSM programs can be created to motivate customers to reduce or shift energy consumption to off-peak periods.

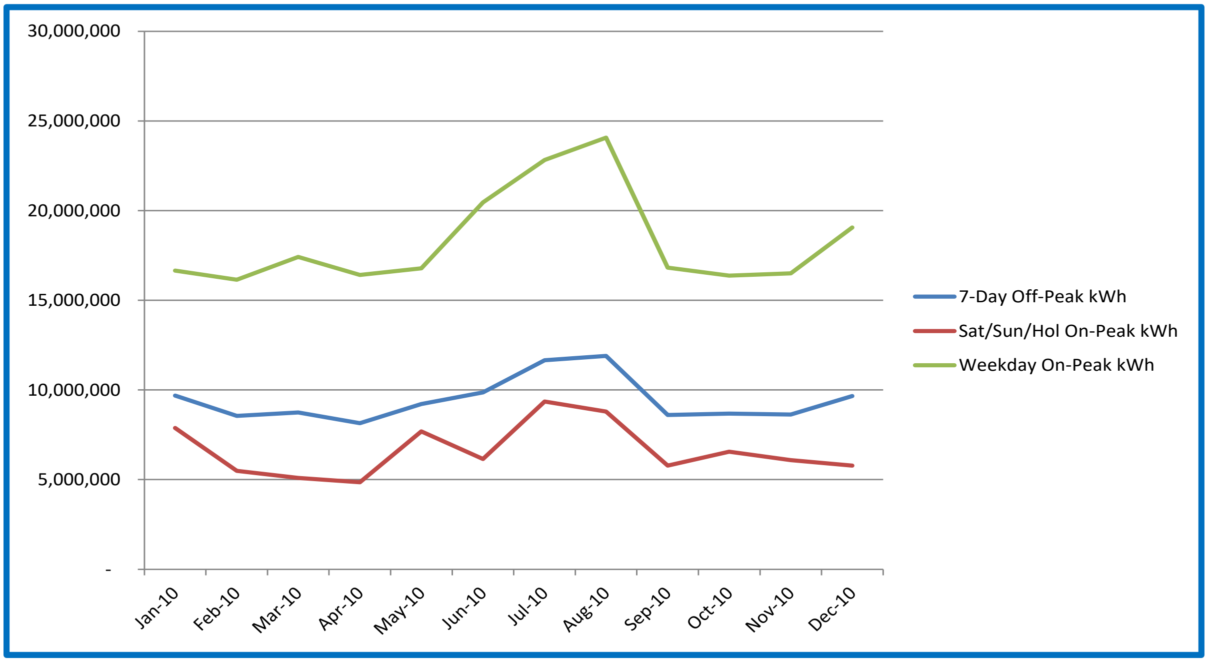


Figure 14 – 2010 Annual Energy Purchases by Period

The figure below illustrates how implementation of the Smart Grid Elements will impact the demand and energy baseline amounts over the next fifteen years.

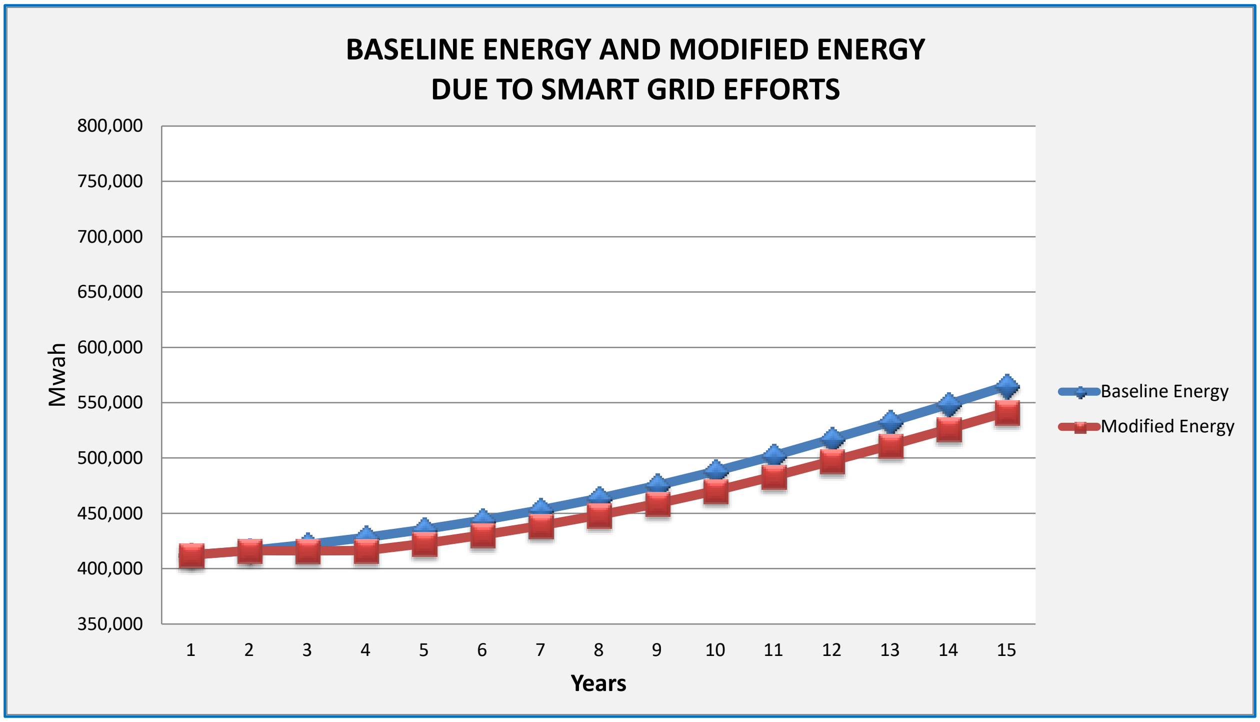


Figure 15 - Baseline Energy & Modified Energy Due to SG Efforts

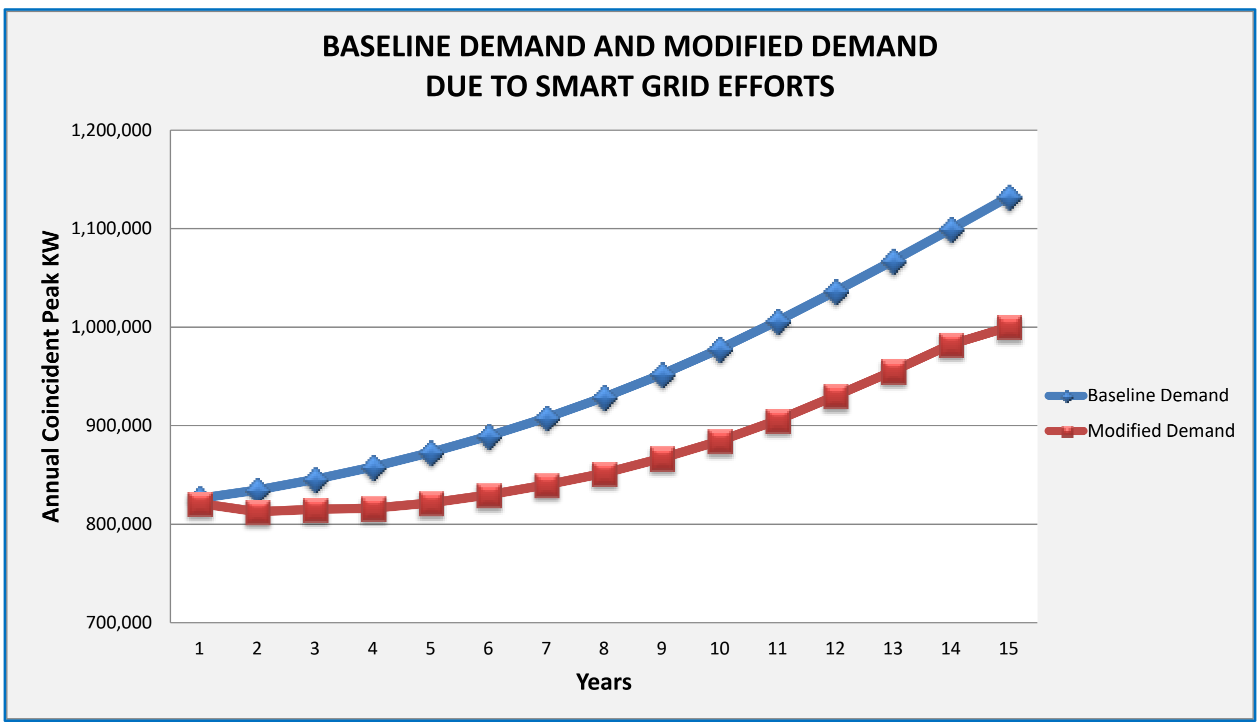


Figure 16 - Baseline Demand and Modified Demand Due to SG Efforts

Another perspective on this is to view it as dollar savings associated with energy and demand for each of the major cost reduction measures: DSM, CVR and DVC. Note that DVC drops off as CVR is implemented.

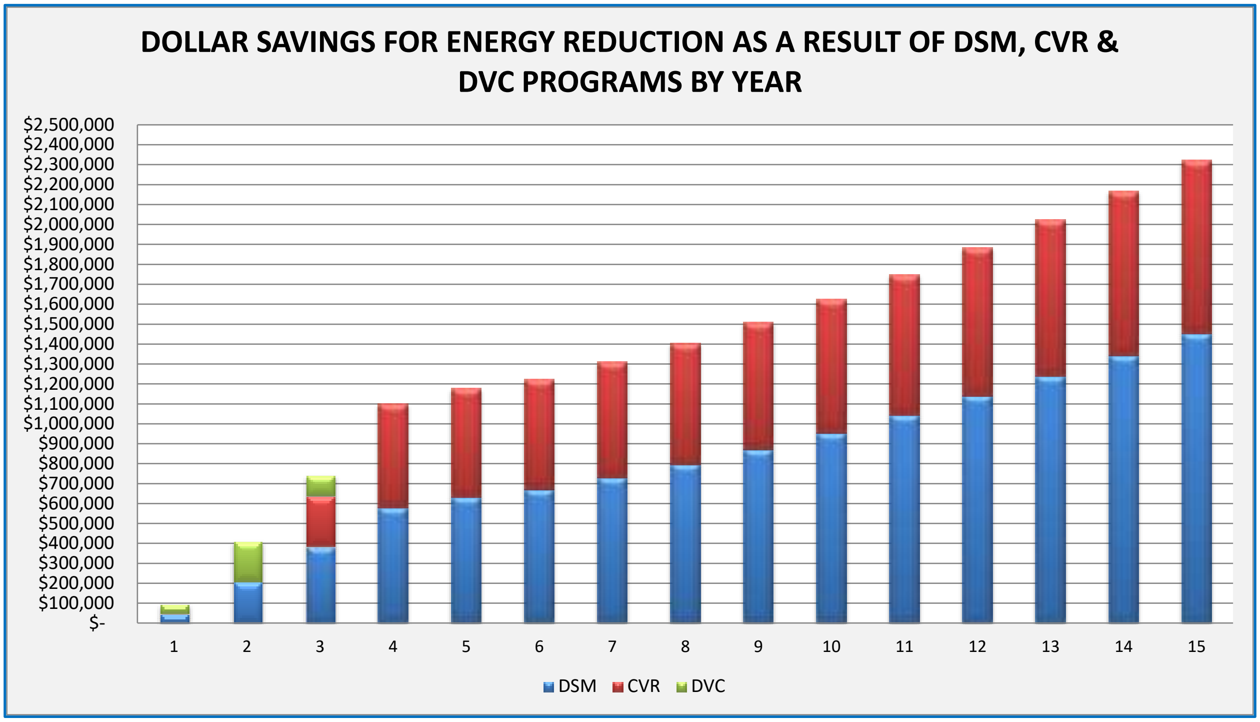


Figure 17 - Dollar Savings for Energy Reduction

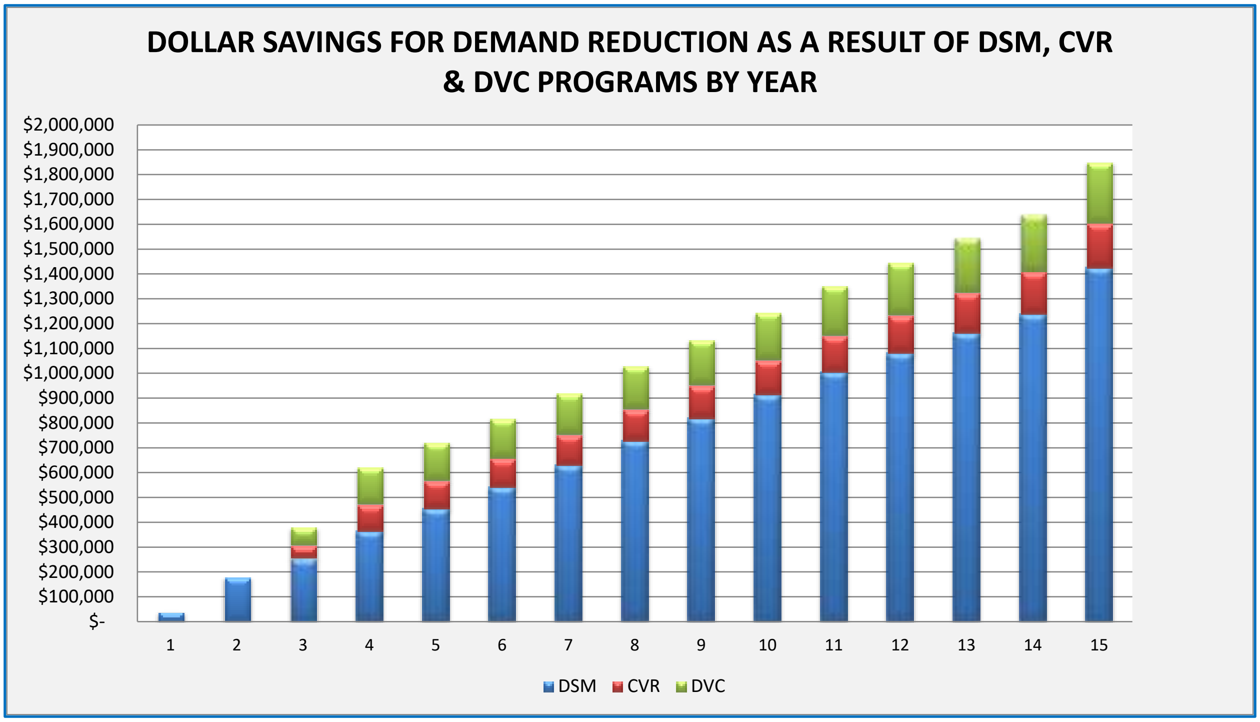


Figure 18 - Dollar Savings for Demand Reduction

ADVANCED METER INFRASTRUCTURE / CORE TELECOMMUNICATION

SPU's deployment of their Smart Meter Communications Network will serve to carry the data streams from a new AMI System. This network will be deployed across SPU's Electric Service Area, which is approximately 40 square miles and will serve 26,787 electric and water meters, as well as their distribution (DA) and substation automation (SA) devices.

There was a comparison made of different technologies for Smart Grid communication support and a preferred set of technologies to model for this Smart Grid Business Case was chosen. The information provided in this section of the Study will describe the pros and cons of the differing technologies that are commonly used for Internet Protocol (IP) Backbone, Mid-Tier Backhaul, and Advanced Meter Infrastructure (AMI) communications. The requirements and key applications for each of these communication solutions will be described.

Why do we need Smart Grid Communications?

Currently in Smart Utility deployments, there is a need to exchange data between utility control center and the personnel and new equipment in the field. This exchange of two way data and control signals has expanded beyond the conventional SCADA information and control that have been used for many decades. Smart Grid applications such as Advanced Metering Infrastructure (AMI), Distribution Automation (DA), Substation Automation (SA), video surveillance at substations and other critical infrastructure, and Workforce Management all require two way communications. The emerging trend in two way communications has been moving toward an Internet Protocol (IP)-Based communications infrastructure to standardize the communication architecture allowing for an efficient convergence of multiple streams of data traffic..

IP is a packet-based technology that offers many advantages over the traditional Time division Multiplex (TDM) network using T1's from the telephone company. Unlike the TDM technology, messages are separated into variable-length segments and transmitted individually across dynamically created connections. The nature of this technology results in the flexible use of bandwidth providing a more bandwidth efficient network and simpler/lower cost equipment.

IP Backbone

The IP Backbone network provides a highly reliable wide area network that will interconnect many of the utilities key locations (i.e. control center) to the Mid-Tier backhaul and AMI networks. The IP backbone is capable of operation after sustaining a single point of failure in the network as well. All the smart grid devices requiring two-way connectivity to the Smart Grid IT applications in the control center have their traffic routed to the control center over the IP Back bone network.

Mid-Tier Backhaul

A Mid-Tier Backhaul solution is needed to facilitate communication from the Distribution Automation end devices, Substation Automation end devices, and AMI Collectors/Gatekeepers back to the Microwave IP Backhaul transport. The technology modeled in the Shakopee business case is a Point to Multi-Point system that can aggregate many end devices back to one tower. This allows for the most efficient transport of information/data from the customer premises or electric grid back to the Front End/MDM solution. Several different solutions for Mid-Tier Backhaul were evaluated for the Shakopee business case.

AMI (Advanced Meter Infrastructure)

Advanced Meter Infrastructure combines interval data measurement with continuously available remote communications of the smart meters, Home Area Network (HAN) Devices and possibly Distribution Automation devices. AMI systems enable measurement of detailed, time-based information and frequent collection and transmittal of such information to various parties. The AMI system refers to the measurement and data collection system that includes smart meters at the customer premises, two-way communications network between the customer and the utility, and data reception and management systems that make the information available to the utility. The Advantages of deploying an Advanced Meter Infrastructure System are:

1. System Operation Benefits
2. Customer Service Benefits
3. Enabling advanced time of use (TOU) rates – Reducing demand and enabling lower cost off peak energy
4. Control of load control and energy efficiency HAN devices
5. Control and Monitoring of Distribution Automation devices

System Operation Benefits are primarily associated with:

- Reduction in meter reads
- Reduction of associated management and administrative support,
- Increased meter reading accuracy
- Improved utility asset management
- Easier energy theft detection
- Easier outage management

Customer Service Benefits are primarily associated with:

- Early detection of meter failures
- Billing accuracy improvements
- Faster service restoration
- Flexible billing cycles

- Providing a variety of time-based rate options to customers, and creating customer energy profiles for targeting Energy Efficiency/Demand Response programs

Financial Benefits to the utility come from:

- Reduced equipment and equipment maintenance costs
- Reduced support expenses
- Faster restoration and shorter outages
- Improvements in inventory management

Business Drivers for a Smart Grid Communications Network

There are two key business drivers that were considered for SPU's Smart Grid Communications Network as design criteria.

1. Build an end-to-end Smart Grid Communications Network utilizing multiple advanced wireless technologies and expand the existing SPU Wide Area Network (WAN) and Information Technology (IT) network infrastructure to provide backhaul communication for the Smart Grid components.
2. The communications network selected must scale and evolve in a manner that meets the requirements of SPU's Smart Grid Roadmap.

Partnering Opportunities

The City of Shakopee has existing fiber in the area and this was discussed with Shakopee Public Utilities (SPU) in depth discussion. A decision was made not to pursue this option for now for the following reasons:

- The Fiber Optic currently does not run to the Shakopee Sub-Stations
- Client preferred a stand-alone wireless backhaul solution to get the baseline pricing estimate
- This approach would get the client in the ball park with a final solution coming once a vendor had been selected

There is a large natural gas supplier in the area, CenterPoint Energy. They currently operate an Automatic Meter Reading (AMR) Drive-By Gas Metering system for reading their gas meters. CenterPoint Energy was contacted to determine if they had any interest in participating or sharing in the construction of the Telecommunication Infrastructure with SPU. As a natural gas provider, they may require a wired or wireless connection from their meter to the electric meter on the premise. The signal would be moved wirelessly to a local collector, then to local substation and on to SPU's office. In this process data would need to be maintained separately and securely.

William E. Grey, of CenterPoint Energy, stated that they had already invested in an AMR system, which is used throughout Minnesota, including the area served by the SPU. In the event SPU moves forward with Smart Grid development, CenterPoint Energy stated that they would be willing to share technical information related to their AMR system and evaluate any proposals put forth by SPU that would ultimately benefit CenterPoint Energy rate payers. CenterPoint Energy does not have an interest in participating in the construction of a telecommunications infrastructure at this time.

Business Objectives

The SPU Business Objectives that were considered for SPU's Smart Grid Communications Network are:

1. **Reliability** – Provide reliable coverage across the SPU's electric and water service area by utilizing multiple wireless and fiber network technologies.
2. **Reliability** – The IP Backbone must be designed to support 99.999% uptime and operate during extreme weather events.
3. **Pervasive Connectivity** – Provide two way communications for 100% coverage of SPU's Smart Grid end points (i.e., Smart Meters, Home Area Network (HAN) devices, DA and SA Devices).
4. **Performance** – Provide required data throughput capacity for operational (e.g., Smart Meter reads) and non-operational (e.g., software downloads) data exchange.
5. **Secured** – Comply with SPU's IT Network Security Standards, as well as the NERC and NIST Cyber Security Standards.
6. **Scalable** – System components to have bandwidth scalability and have the ability to expand to meet future usage requirements and service territory expansion (service territory expansion information provided by SPU).
7. **Return on Investment** – The chosen Smart Grid Communications Network will be cost effective as compared to other viable solutions.

Design Assumptions

The following SPU facilities can be utilized to build communications facilities as needed for the Smart Grid Communications Network:

1. Shakopee Service Center
2. Blue Lake Substation
3. Dean Lake Substation
4. Pike Lake Substation
5. Shakopee Substation
6. South Shakopee Substation
7. Pump House #2 Golf Ball Water Tower
8. Pump House #3
9. Pump House #4
10. Pump House #6
11. Pump House #9
12. Dominion Avenue Water Tower
13. Pump House #15 Control House
14. Pump House #16

15. Pump House #20
16. Booster Station
17. Canterbury Road Tower
18. Standpipe Water Tower
19. Kelley Circle Tanks 5 and 6

The image in the figure below shows the SPU facilities (referred to as "assets") that were used in the Smart Grid Network Design.

red	City of Shakopee Service Territory	yellow	IP Backhaul Microwave Path
teal	Proposed Township of Jackson Annexation	green	Mid-Tier Backhaul WiMax
magenta	Proposed Township of Louisville Annexation	orange	AMI Solution

Figure 19 – SPUC Service Territory for Communication Site Assets

Private versus Public Networks Discussion

There is an ongoing debate as to whether a utility should build a private communications network or partner with a Public Carrier for its IP Backhaul, Mid-Tier and even AMI communication solutions. When considering private vs. public networks one must consider the following six key requirements: Availability, Survivability, Coverage, Latency, Security and Life Cycle. Each of these is discussed in more detail in order to fully understand the issue as it pertains to SPU. The Six Key Requirements are all equally important and they were not placed in the document in any particular order. Security can definitely be considered most important to a critical communications network.

Availability is a measure of how reliable a system performs over an extended period of time. Mission-critical communications — those that are required for operation of the power grid — are needed to support a network availability of 99.999% or higher. That equates to only just over five minutes of unplanned downtime per year.

The availability of public networks has improved in recent years. Large networks such as AT&T and Verizon Wireless have added redundant capabilities into their systems, but at times experience network congestion problems.

Survivability is critical to utilities. The network infrastructure must survive, or withstand, environmental problems, accidents and long power outages. Utilities deploying a private network can increase survivability by adding redundancy and power generation backup solutions to their communications networks.

Historically, reliance on public networks has left utilities with little recourse other than to "call the carrier and submit a trouble ticket"; however, in recent years large networks have added redundant wireless capability and increased their survivability for natural disasters such as tornadoes and ice storms.

Coverage or the extent of communications service within a given area is specified to be ubiquitous across the utility's service territory. Specifically, the utility requires communications coverage to its Smart Meters and to its DA and SA infrastructure. The utility needs to cover a large service territory, regardless if there are customers or devices located there. A Service provider focuses on covering customers. Covering territory and population is not the same thing. Public Carrier communication networks have been built to provide mobile phone service. Their towers are oriented to highways, shopping malls, sporting venues and downtowns. A private utility network gives the utility the flexibility to design the coverage area to meet its territory coverage requirements. The positive aspect of public network coverage is that it is nearly ubiquitous and therefore may serve utilities fairly well.

Latency requirements for utilities vary by applications. AMI solutions currently do not require very low latency communications. Today's DA and SA solutions do require much lower latency to support a Self-Healing Electrical Grid. This can require computer controlled switching along the distribution system and in the substation. With the advent of 4G technologies the public carriers do have a lower latency solution. However, due to the requirement to share their new 4G network resources with other customers, the utility will suffer some degradation in service due to busy hour network congestion. This could be addressed through a uniquely constructed Service Level Agreement (SLA) between the utility and their Carrier.

Security requirements for utilities continue to grow. Both private networks and public networks provide information security and protection. Access to critical systems and protection of sensitive data is needed to ensure system integrity and availability even under adverse conditions.

This is typically addressed by deploying end-to-end tunneling solutions that encrypt data between the utility control center and the device in the field.

Life Cycle is a problem with public carriers due to the speed at which they modernize their infrastructure. A public carrier will completely upgrade its infrastructure every four to six years, while a utility implement communication capital investment upgrades approximately every 15 years. A utility using a public carrier for its network communication needs will have to upgrade the meters and radios when forced by the cellular company. This imposes a greater cost to the utility.

One possible way to address this upgrade timeframe disparity is to establish an agreement with the potential public network provider and request equipment upgrades at a predetermined price structure, thereby avoiding financial and operational surprises.

Data Transport Discussion

Utilities deploying Smart Grid networks have several options for transporting data collected from customer and the electric grid. The information herein is provided as an overview of those options for the following three key applications.

- IP Backhaul (high speed, low latency, point to point, and very reliable)
- Mid-Tier Backhaul (broadband speed, coverage for entire service area and supports 1-3 devices per square mile)
- AMI Solutions (coverage for all the water and electric meters as well as Distribution Automation devices throughout the service territory)

IP Backhaul Options for Smart Grid Communications

The IP Backhaul segment of Smart Grid Communications can be owned by the utility or provided by third party service providers. Its main function is to aggregate and transport customer data, distribution automation data, substation automation data and mobile workforce data from the utility head end to the mid-tier backhaul and AMI networks. The IP backbone must be very reliable, very high bandwidth, low latency, very secure and with strong Quality of Service (QOS) support.

Utilities deploying Smart Grid networks have several options available for an IP Backbone solution. There are several factors that have to be considered for each technology, including:

- Licensed Point to Point Microwave
- Unlicensed Point to Point Microwave
- Fiber Optic Communications

- Leased Backbone Capacity

The main function of the IP Backhaul is to aggregate and transport customer data, distribution automation data, substation automation data and mobile workforce data from the utility head end to the mid-tier backhaul network. The data rates required for a utility such as SPU can range from 50 Mbps to 300 Mbps depending on the amount of traffic expected. There are four main technologies that may be implemented by utilities for IP Backhaul of Smart Grid. In the figure below “Summary of Backhaul Options for Smart Grid Communications” there is a detailed description of the options available and pros and cons of each of them.

Leased Backbone

As mentioned earlier, selection of either a private or public networks requires consideration of six key requirements: Availability, Survivability, Coverage, Latency, Security and Life Cycle. The positives to using Leased IP Backbone include virtually unlimited capacity, low latency and no risk to interference.

The items that weigh on the negative side include high cost of ownership and a high cost for maintenance expenses. Additionally, the utility has to deal with a lack of control as the infrastructure is owned by another company.

Note: A leased IP Backbone will not support Transmission Substation Relay Protection schemes.

Fiber Optic Communications

Fiber Optic Communications offers virtually unlimited capacity, low latency and no risk to interference due to spectrum issues. Additionally, this technology can be engineered for very high availability. The main negative of fiber optics is a very high cost to deploy the technology. Costs vary according to terrain and morphology and range anywhere from $10,000 to $250,000 per mile. The City of Shakopee does have some existing fiber in the area and this was discussed with Shakopee Public Utilities (SPU) in depth discussion. The Fiber Optic currently does not run to the Shakopee Sub-Stations and for now Shakopee Public Utilities (SPU) preferred a stand-alone wireless backhaul solution to get the baseline pricing estimate. This approach would get the client in the ball park with a final solution coming once a vendor had been selected

Licensed Point to Point Microwave

Point-to-Point Microwave is a well-proven technology delivering 99.999% availability, advanced security and encryption, and low latency for the most critical communication requirements in Smart Grid networks. The negatives to Licensed Point-to-Point Microwave include a high deployment cost of $35,000 to $110,000 per link.

Unlicensed Point to Point Microwave

Point-to-Point Microwave is a well-proven technology delivering 99.999% availability, advanced security and encryption, and low latency for the most critical communication requirements in Smart Grid networks. Additionally, the deployment cost of unlicensed microwave is much lower than licensed microwave. Those costs range from $5,000 to $30,000 per link. The negative in using unlicensed microwave versus licensed microwave is the risk of interference in using an unlicensed frequency band. This risk can be minimized with proper Radio Frequency (RF) engineering techniques.

Recommended IP Backhaul Solution

For their Smart Grid deployment West Monroe Partners recommends SPU to use an Unlicensed Point-to-Point Microwave IP Backhaul solution. Overall, the use of microwave over fiber comes down to a financial one. Unlicensed microwave solutions are cheaper to own than licensed solutions and due to encryption techniques available the option of unlicensed microwave is just as secure as a licensed option.

Compared to leasing bandwidth from a carrier a private microwave IP Backbone network delivers immediate operational expense (OpEx) reduction and shortened return on investment timeframe.

It is recommended that the final selection to deploy and install a particular type of technology and vendor should be made based on the results of a formal Request for Proposal (RFP) process.

Summary of Backhaul Options for Smart Grid Communications

	Category	Shakopee Requirements	PTP Microwave - Licensed	PTP Microwave - Unlicensed	Fiber	Leased Backbone Capacity
Critical Application	**Support Transmission Substation Relay Protection?**	**Not Required**	yes	No	yes	No
Cost of Ownership	**Total Cost of Ownership**	**Lower is better**	Good	Very Good	OK, Expensive upfront	Very Expensive; limited capital investment coupled with long term OpEx expenditures
	Deployment Cost (Capital)		$45 to $125 per Link for Equipment (Radio + Antenna System + Installation+Spectrum) not including tower / civil)	$5K to $30K per Link	Cost Increase per Foot/Meter, Very expensive if it requires trenching/burial ($10K to $250K per mile)	$500 to $2500 for upfront capital
	Maintenance Expenses		5% of Capital Cost (Equipment and Installation)	5% of Capital Cost	5% of Capital Cost	$200 to $1000 per T1 per Month, $2000 to $5000 per DS3 per Month
Additional Communication Characteristics	**Legacy Backbone**	**Narrowband SCADA**	All Environments	Suburban - Rural	All Environments	Any
	Populations Density	**Suburban**	All Environments	Suburban - Rural	All Environments	Any
	Terrain and Foliage	**River Valley, South Shakopee Substation has some coverage challenges,**	Requires Line of Sight (LOS)	Requires Line of Sight (LOS)	Potential cost increase with difficult terrain: Water, Mtns, Deserts	No issue as Leased Lines have already been deployed
	Capacity	**Need about 50 Mbps on the uplink**	10 Mbps to 700 Mbps (Full Duplex)	10 Mbps to 300 Mbps (Half Duplex)	Virtually Unlimited (Dense Wave Division Multiplex (DWDM), multi-fiber Cable, 10 Gbps/frequency)	Virtually Unlimited (Just buy more, it just costs money)
	Latency/Jitter		150-500 nsec per hop/Low Jitter	2-30 ms per hop/low-medium Jitter	5 ns per meter/Very Low Jitter	P2P t1 circuit = 5 ns to 8 ms / Very Low Jitter
	FCC Spectrum Requirements		Requires Licensed Spectrum (6GHz, 11GHz, 18GHz, 23GHz and 80GHz)	Free Spectrum (5.3GHz, 5.4GHz, 5.8GHz, 5.9GHz, 24GHz, 60GHz)	No Spectrum but Requires Right of Ways	Regulation/Procurement Issues Taken care of by Service Provider
	Spectrum Interference Risk		Extremely Low Risk to Interference	Interference Risk, Can be minimized with proper RF Planning, Adaptive Modulation, Technology Selection (Far Field: Highly directional High Gain Antennas, Near Field: RF coordination at Radio sites)	No Risk to Interference	No Risk to Interference
	Civil Engineering Impacts and Real Estate Requirements	**Leverage the 3 Water Towers**	Need High Spot Locations - Might need to put in towers, Back-up Power Generators, Local Permitting May be required for new Tower	Need High Spot Locations-might need to put in towers, Back-up Power Generators, Local Permitting May be required for new Tower	Construction Work if trenching required	Construction Work if trenching required
	Deployment time		Fast Deployment time	Fast Deployment time	Time increases with distance	Quick (30 days) if capacity is available
	Equipment Relocation		Equipment can be moved if necessary	Equipment can be moved if necessary	Fiber Relocation is Very Expensive	Cannot be relocated
	Climate Impact		Adaptive Modulation and proper link planning required to reduce climate effects	Adaptive Modulation and proper link planning required to reduce climate effects	No influence from climate (susceptible to major outages due to backhoes, animals, and trees)	No influence from climate (susceptible to major outages due to backhoes and trees)
	Joint Use/Collocation		May collocate antenna on an existing tower owned by a third party	May collocate antenna on an existing tower owned by a third party	May need to install fiber on Telco poles; may need to perform make-ready work on own poles prior to installing fiber.	No direct Joint Use issues.
	Link Availability	**Looking for (5) 9's**	Can be Engineered for Very High Availability	Can be Engineered for Very High Availability	Can be Engineered for Very High Availability	Can be Engineered for Very High Availability
Recommendations	**PTP Microwave - Unlicensed meets the Requirements at a much lower price.**		**Effective Solution, but much more expensive than unlicensed solution. This will deliver a reliable Ring of Bandwidth that will deliver broadband to/from the substations, pump houses and DA devices.**	**Most Cost Effective solution for a reliable Ring of Bandwidth that will deliver broadband to/from the substations, pump houses and DA devices.**	**Too expensive for TCO, slower deployment, and more expensive maintenance.**	**Too expensive for TCO and does not meet availability requirements.**

Figure 20 - Summary of Backhaul Options for SG Communications

KEY	
Green	Perferred Solution and Best Meets Requirements
Yellow	Optional Solution and Still Meets Requirements
Red	Least Preferred Solution and Doesn't Meet Requirements

Mid-Tier Backhaul for Smart Grid Communications

The Mid-Tier Backhaul segment for Smart Grid Communications supports real-time two-way broadband communications between the IP Backhaul locations and the utility's DA and SA devices. This mid-tier backhaul can also be used to backhaul the data traffic from the AMI collectors and base stations.

The Mid-Tier Backhaul network can be owned by the utility or provided by third party service providers. There are three main categories of Mid-Tier backhaul solutions available to the utility. They include:

- Fixed Wireless Point to Multi-Point Technology
- Wireless Mesh Technology
- Public Carrier (3G/4G Mobile Data Solutions)

The Mid-Tier Backhaul segment of Smart Grid Communications supports real-time two-way broadband communications between the Microwave tower and the customer's DA and SA devices. This mid-tier backhaul can also be used to support Cell Relays and Collectors in AMI Mesh Technologies. In the figure below a summary of Mid-Tier Backhaul Options for Smart Grid Communications is shown. This represents a detailed description of the options available and the pros and cons of each.

Public Carrier

The previously mentioned public versus private discussion is valid for Mid-Tier Backhaul. The same factors must be considered: Availability, Survivability, Coverage, Latency, Security and Life Cycle.

Specifically for Mid-Tier backhaul the utility should consider Cost of Ownership and Control. The utility does not control the Carrier's Communications Network. So, in effect a utility is held hostage to the public carrier's performance standards. Another major factor to consider is the cost. A utility that uses public carrier facilities for its Mid-Tier Backhaul will incur monthly payments to the carrier for each device. Over time this will outweigh the cost of deploying a private network.

The positive of a public carrier for Mid-Tier Backhaul is that the carrier's network is already built and awaiting use. This approach may work well for non-critical communications applications.

Unlicensed Wireless Mesh

A wireless mesh network used as a Mid-Tier Backhaul has many positive attributes. The mesh network consists of many network nodes all spaced apart approximately every ¼ mile. Utilities that have deployed such networks often use streetlight poles and/or electric distribution poles to mount the network nodes, as this technology does not require the construction of towers. What is required for a wireless mesh network is bandwidth injection. So, in effect, utilities that have numerous locations providing broadband, such as fiber or existing microwave links, can deploy a mesh network and avoid the cost of new tower infrastructure.

The positives of a wireless mesh include: self-healing network, low latency, high availability and control by the utility. The negatives associated with this technology are: Bandwidth injection is required. So, a utility may have to construct a microwave tower or install fiber to many points in their service territory. It also takes much more time to properly optimize this network.

Wireless mesh as a Mid-Tier Backhaul becomes more favorable when mobile data services are also required as this technology supports that application.

Point to Multi-Point

The most cost effective solution for delivering broadband to/from the substations, pump houses and DA devices. There are several spectrum options for this approach ranging from 900 MHz to 5 GHz. One very popular Point to Multi-Point network utilizes Worldwide Interoperability for Microwave Access (WiMAX) technology operating at 3.65 GHz.

The positive aspects of this type of network are large bandwidth, low latency, and high capacity. This solution is excellent for DA and SA operation. Point to Multi-Point also supports fixed video. However, the negative aspect of Point to Multi-Point technology is the lack of coverage that is encountered in difficult terrain areas. The higher a signal's operating frequency the harder it is for that signal to penetrate dense foliage. While lower frequencies have been deployed, they suffer from a lack of bandwidth which fails to adequately support video and some event data being developed for DA technologies.

Recommended Mid-Tier Backhaul Solution

For this Smart Grid deployment West Monroe Partners recommends SPU deploy a point to Multi-Point Solution for Mid-Tier Backhaul.

Once again the use of a Point to Multi-Point solution comes down to a financial one. The Total Cost of Ownership (TCO) is lowest for a Point to Multi-Point network in comparison to a Wireless Mesh or Public Carrier solution and the bandwidth that solution provides is sufficient for DA and SA use, as well as potential AMI support.

Compared to leasing bandwidth from a carrier a private mid-tier point to multi-point network delivers immediate OpEx reduction and shortened ROI timeframes.

It is recommended that the final selection to deploy and install a particular type of technology and vendor should be made based on the results of a formal RFP process.

Summary of Mid-Tier Back Haul Options for Smart Grid Communications

	Characteristic	Utility Requirements	Fixed Wireless	Unlicensed Mesh	Public Carrier
Critical Application and Characteristics	Types of Technologies		Fixed WiMAX (2.3 GHz, 2.5GHz, 3.65GHz, 5 GHz), 900 MHz & 5 GHz, Soon TV White space (500 MHz - 700 MHz)	900 MHz/2.4GHz/5 GHz Mesh	3G (EVDO, HSPA) 4G (WiMAX, LTE)
	Typical Deployment	Suburban	Urban, Suburban, Rural	Urban, Suburban	Urban, Suburban
	Mobile Data Support	Nice, but not required	No	Yes	Yes
	DA Communications	Include	OK	Good	Tough in Rural and in Storm
	Fixed Video Support	Include	Very Good	OK	Poor- Upstream Bandwidth is limited
	Substation SCADA	Include	Very Good	OK	Poor - Can't Control Availability
	Capacity	Need up to 4 Mbps per Substation on the uplink to Support SCADA, AMI, and Video services	2Mbps - 15 Mbps	1 Mbps - 15Mbps	250Kbps - 3 Mbps
	Round Trip Message Latency	Consistent Latency is better for VOIP at the Substations and Pump Houses	20 ms - 40 ms	10 ms - 250 ms	100 ms - 5 seconds
Cost of Ownership	Total Cost of Ownership	Lowest is Best!	Lowest	Good for Urban, Expensive suburban, very Expensive Rural	Very Expensive
	Infrastructure Cost (Capital)		$15K - $50K/Base Station (Need 1 per 5 to 50 Square Miles)	$2500/AP (Need 2-10 AP's per square mile)	None (Service Provider takes care of infrastructure)
	Number of Base stations/Access Points		1 Base Station/AP cluster per 2-5 Square Miles	2-15 Access Points per Square Mile	Utility Does not control the RF Coverage with Additional equipment deployment
	Coverage		Can be Problem in Urban Canyons and Heavy foliage	Requires lots of AP's but easy to customize coverage	Cover Issue in Rural Areas since Utility Does not control the RF Coverage with Additional equipment deployment
	Maintenance Cost		5% of Capital Costs	5-10% of Capital Costs (Much more if battery back-up required at the APs)	Very Expensive, $25-$50/Month per Connection
Additional Communication Characteristics	Regulation	Flexible	Licensed (2.3 GHz, 2.5 GHz), Licensed Lite (3.65 GHz), Free Spectrum (500-700MHz, 900MHz, 2.4 GHz, 5GHz ISM Band)	Free Spectrum (900MHz, 2.4 GHz, 5GHz ISM Band)	Not Required
	Spectrum Interference Risk	Lower is Better	Radio Interference in Unlicensed Band, Low in 3.65GHz Band, very low in 5 GHz	Radio Interference Risk, Can be minimized with proper RF Planning, Adaptive Modulation, Technology Selection	Very Low
	Civil Issues	Have 3 Water towers and SCADA Poles at substations	Need High Spot Locations - Might need to put in Towers, and Back-up Power Generators Recommended	Need 24 X 7 Power to the Street Lights for collectors.	No Issues, managed by carrier
	Deployment time	Would like this rather Quickly to see Benefits	Fast Deployment time for initial coverage, might have to adjust Subscriber modules and put in Repeaters to tune coverage	Takes time to tune the Network to get good coverage	Fast Deployment Time, if coverage is available
	Terrain and Foliage	Suburban, River Valley, Deciduous Trees	Heavy Foliage and Terrain can Require more Infrastructure	Heavy Foliage and Terrain can Require more Infrastructure	Heavy Foliage and Terrain can create coverage holes, can't tune coverage though
	Expandability		Additional Base Stations and Frequencies Can Be Added. Fewer locations mean easier Hardware upgrades and maintenance and power generation backup.	Can add more APS for capacity, but expensive for hardware upgrade and battery backup	At the mercy of the carrier.
	Recommendations	**Fixed WiMAX is Best if Mobile Data Services are Not Required**	**Most Cost Effective solution for delivering broadband to/from the substations, pump houses and DA devices.**	**Much more cost for required capabilities. Usually an interesting solution when mobile data is needed.**	**Too expensive for TCO and does not meet availability requirements.**

Figure 21 - Summary of Mid-Tier Backhaul Options for SG Communications

KEY	
Green	Perferred Solution and Best Meets Requirements
Yellow	Optional Solution and Still Meets Requirements
Red	Least Preferred Solution and Doesn't Meet Requirements

AMI Technology Solutions

Advanced Meter Infrastructure (AMI) technology options provide utilities improved and efficient access to electric, gas and water utility meters. This occurs through a dual process of placing Smart Meters in customer premises and building a two-way AMI communications network to remotely read and control the meters, execute service disconnects and reconnects, retrieve interval energy and power quality data retrieval, remote software downloads and configuration changes, and serve as the gateway to the customer Home Area Network.

The technologies evaluated in this document include:

- Narrowband PLC AMI
- Wideband PLC AMI
- Fiber Optic AMI
- Public Carrier AMI
- Unlicensed Wireless Mesh AMI
- Licensed Tower AMI

The AMI technology solutions discussed below provide the utility with improved and efficient access to both electric and water utility meters. They are described with their pros and cons with respect to the utility. The figure below summarizes the AMI Options for Smart Grid Communications in detail, describing the options available, with the pros and cons for each solution.

Narrowband PLC

Narrowband Power Line Carrier is a technology where the utility's power lines are used in the transmission of telecommunications signals. This is made possible thru the injection of a low energy signal into the power line. The frequency range used for communication is 3 KHz to 148.5 KHz.

The main advantage of Narrowband Power Line Carrier technology is that the utility already owns the power lines carrying the information. There is a cost savings, as the utility does not have to deploy communications towers and added communications cabling.

The drawback associated with Narrowband PLC is that power lines are inherently hostile to signal propagation. The power line is electrically "contaminated", which makes reliable data communications difficult. The power line acts as a large radiator, creating and inducting interference.

Wideband PLC

Wideband Power Line Carrier is similar to Narrowband PLC in that it is a technology where the utility's power lines are used in the transmission of telecommunications signals. This is made possible thru the injection of a low energy signal into the power line. The frequency range used for Wideband PLC is 1.7MHz to 30MHz.

The advantage of Wideband PLC technology is the higher throughput available from Orthogonal Frequency Division Multiplexing (OFDM) modulation techniques. Throughput speeds greater than 100

Mbps have been tested in the latest technology. A big advantage to this technology is that there is no RF attenuation from the meter to the devices inside the home.

The disadvantages are that this is still a newer technology. It is noisy and suffers from strong fades due to multi-path. Additionally, there is a high cost associated with this new technology. Interference is still a problem as well because the main conductor, the power line, is unshielded and untwisted and acts as an antenna.

Fiber Optic Communications

As stated in a section above, fiber optic communications offers virtually unlimited capacity, low latency and no risk to interference due to spectrum issues. Additionally, this technology can be engineered for very high availability. The main negative of fiber optics is a very high cost to deploy the technology. Costs vary according to terrain and morphology and range anywhere from $10,000 to $250,000 per mile. The City of Shakopee does have some existing fiber in the area and this was discussed with Shakopee Public Utilities (SPU) in depth discussion. The Fiber Optic currently does not run to the Shakopee Sub-Stations and for now Shakopee Public Utilities (SPU) preferred a stand-alone wireless backhaul solution to get the baseline pricing estimate. This approach would get the client in the ball park with a final solution coming once a vendor had been selected

Public Carrier

The same public versus private discussion listed above applies to use of Public Carriers for AMI solutions. The same factors must be considered: Availability, Survivability, Coverage, Latency, Security and Life Cycle.

As stated for Mid-Tier backhaul the utility should consider Total Cost of Ownership and Control factors when considering AMI solutions. The utility does not control the Carrier's Communications Network. So, in effect a utility is held hostage to the public carrier's performance standards. Another major factor to consider is the cost. A utility that uses public carrier facilities for AMI solutions will have monthly payments to the carrier for each meter. Over time this will outweigh the cost of deploying a private network.

Unlicensed Wireless Mesh AMI Technology

The leading technology being deployed by utilities for AMI solutions in the United States today is wireless mesh. There are several vendors; however, all of them operate similarly due to open wireless mesh standards. Another reason for wireless mesh popularity is that it is a mature, proven technology that has proven to be manageable, robust, capable of high performance, and secure.

Most importantly, wireless mesh is ready to meet the evolving needs of future smart grid applications through an ongoing innovation roadmap and established collaborative mechanisms (e.g., the Wi-Fi Alliance and IEEE).

The negatives with Wireless Mesh solutions are that they operate in the unlicensed 902-928MHz frequency band. This is one of the most populated frequency bands used in the United States. The power output of wireless mesh meters is restricted to 250 milliwatt, which greatly reduces the range of the meters.

Licensed Tower AMI Technology

Licensed Tower AMI technology is gaining popularity in the United States. The biggest difference in this technology and in the unlicensed mesh technologies is that Licensed Tower uses a secure spectrum and has meters that operate at a higher output power. The meters used in Licensed Tower AMI technologies have an output of 2 Watts. Due to the higher power output this technology works very well in rural environments.

The operating frequencies of Licensed Tower AMI technology are also in the 900 MHz range. The biggest difference is that this spectrum is secure. Another advantage to using Licensed Tower AMI is the simpler network. The meters communicate directly with the tower. This eliminates the need for Gateways, Cell Relays and Collectors. This technology is very good for utilities that can use existing infrastructure such as water tanks and existing communications towers.

Recommended Solutions for AMI Communications

The two AMI Technology Solutions that best fit Shakopee Public Utilities requirements are: (1) Licensed Tower AMI; and, (2) Unlicensed Wireless Mesh AMI. In comparing the two solutions, the following key items have been considered.

- **HAN Network** – Both solutions place smart meters in the customer premises and utilize ZigBee Home Area Network technology (2.4 GHz).
- **Bandwidth** – Licensed Tower has up to 172 Kbps per channel full-duplex. Unlicensed has 8 Kbps after hops.
- **Latency** – Licensed Tower has less than 100 millisecond of latency due to the direct tower to the endpoint communications and no interference. Unlicensed has several seconds of latency proportional to the number of hops required and interference encountered.
- **Range** – Licensed Tower has extensive range between end points and network nodes due to the greater power output at the meter. Unlicensed systems average approximately ¼ mile due to an output power of 250 mW.
- **Total Cost of Ownership** – Licensed Tower AMI systems have a low cost of ownership in urban, sub-urban and rural environments. Unlicensed Wireless Mesh AMI systems have low cost of ownership in urban and sub-urban environments but a high cost in rural environments due to the difficulty of the mesh nodes to communicate at great distances. They require additional hardware such as range extenders or more towers.

Both the Licensed Tower AMI solution and the Wireless Mesh AMI solution will work very well; however, due to the higher power output of the licensed solution meters, greater range, licensed spectrum and lower maintenance of the Licensed Tower equipment, West Monroe Partners feels that the Licensed Tower solution will meet the requirements of the Utilities at an overall lower cost of ownership. So, for SPU's Smart Grid deployment West Monroe Partners recommends a Licensed tower AMI Solution.

The final selection of vendor and technology should be done as part of a formal RFP process, to assure the best value to the Utilities.

Summary of AMI Options for Smart Grid Communications

	Characteristic	Utility Requirements	Licensed Tower	Unlicensed Mesh	Narrow Band PLC	Wide Band PLC	Public Carrier	Fiber
Critical Application and Characteristics	**Typical Deployment**	**Suburban**	All Terrain	Urban, Suburban	Rural	Urban or 220 V Systems (e.g. EU)	All Terrain (used as hole filler for Mesh Systems sometimes)	Municipalities already deploying voice, Video, data to the home
	Example Vendors		Sensus, Aclara - Hexagram, Tantalus	Cooper (Eka Systems), Itron, SSN, L&G, Elster	Cooper (Turtle), Aclara - TWACS, L&G (Hunt)	Echelon	Smart Sync - GSM, GE/Grid net WiMAX, Trilliant Cell Readers, Elster GSM, etc.	Tantalus
	AMI Interval Energy Read Success Rate		Excellent (>99%)	Good (96%-99%)	Lower (95%) and troublesome in dense deployments	Excellent (>99%)	OK (~95%) depends on carrier coverage	Excellent (>99%)
	Support for Water and Gas on Same AMI Network	**Water and Electric**	Yes	Yes, but need electric close by to connect to Mesh to the collector	Very poor	No	No	No
	Support for DA Communications	**Want DA Communications as well as AMI**	Excellent	OK, but shared bandwidth with AMI and can be questionable during Storm due lack of power to collectors	Poor, very slow and would be questionable during an outage if meters are sending outage messages	NONE	OK	NONE
	Capacity	**Future Expansion is Important**	50 kbps - 500 kbps	17.6kbps - 250 kbps	Very, Very Low	~200kbps	50 kbps - 500 kbps	Virtually Unlimited
Cost of Ownership	**Total Cost of Ownership**	**Cost Effective Is Important**	Lowest for Urban/Suburban, Good for Rural	OK for Urban and Suburban, Expensive for Rural	Lowest for Very Rural	Very Expensive	Very Expensive	Very Expensive
	Meter Cost (Capital)	**Cost Effective Is Important**	Competitive meters with integrated communications	Competitive meters with integrated communications	Expensive - No Integrated Meters and Communications	Competitive Residential meters with integrated communications, limited choice for Commercial Meters	Expensive AMI Card - Best as hole filler or higher end C&I Meters	Expensive - No Integrated Meters and Communications
	Multiple Meter Manufactures?		Yes	Yes	Yes	No	Yes	Yes
	AMI Maintenance Cost	**Lower is Better!**	5% of AMI Capital Costs	10% of AMI Capital Costs (Much more if battery back-up required at the Collectors)	5% of Capital Costs	5% plus ~$40/month per Transformer for Carrier Backhaul	Very Expensive (Monthly Payments to Carrier per meter)	5% of Capital Costs, but may have much shorter life span due fast carrier technology change out

Figure 22 - Summary of AMI options for SG Communications (Part 1 of 2)

Summary of AMI Options for Smart Grid Communications

	Characteristic	Utility Requirements	Licensed Tower	Unlicensed Mesh	Narrow Band PLC	Wide Band PLC	Public Carrier	Fiber
Additional Communication Characteristics	**Latency for On-Demand Read**	**3-5 Seconds**	3-5 seconds	5-60 seconds	30 seconds	3-5 seconds	500ms -5 seconds	2-3 seconds
	FCC Spectrum Requirements	**Flexible**	Requires Spectrum (900 MHz Spectrum for Sensus, 400 MHz for Aclara)	Free Spectrum (900MHz and 2.4 GHz ISM Band)	Not Required	Not Required	Carrier owns frequency	Legislative concerns with municipal entities building additional broadband networks
	Spectrum Interference Risk	**Don't want to have to deal with Interference**	Extremely Low Risk to Radio Interference	Radio Interference Risk, Can be minimized with proper RF Planning, Adaptive Modulation, Technology Selection	Power Line Interference with Many homes on a feeder.	Low Risk of Power Line Interference	Very Low	No Risk to Interference
	Civil Issues	**Can leverage existing SCADA Poles and Water Towers**	Need High Spot Locations - Might need to put in Towers, and Back-up Power Generators Recommended	Need 24 X 7 Power to the Street Lights for collectors.	No Significant Issues, Equipment is located in Substation.	Need to locate backhaul at the distribution transformer. Tricky with underground distribution	None	May require trenching fiber to the NID/Meter.
	Deployment time	**Cost Effective Is Important**	Fast Deployment time	Takes time to tune the Network to get high read success rate	Fast Deployment Time	Takes time to tune the Network to get high read success rate	Very Fast - Where there is coverage (great for C&I and trials)	Longer - Takes time to install Fiber between NID and Meter at every Home....
	Terrain and Foliage	**Suburban, River Valley, Deciduous Trees**	Heavy Foliage and Terrain can Require more Infrastructure	Heavy Foliage and Terrain can Require more Infrastructure	No Impact	Need to get back haul to the Distribution Transformers	at the mercy of the carrier	Potential cost increase with difficult terrain: Water, Mtns, Deserts. Not affected by foliage.
	Expandability	**This is important**	Additional Base Stations and Frequencies Can Be Added. Fewer locations mean easier upgrades.	Can add more collectors for capacity, but expensive for hardware upgrade	Capacity upgrade very difficult	Capacity upgrade very difficult and lots of equipment	at the mercy of the carrier	Virtually Unlimited
	Interoperability		System only works with Same Vendors Endpoints	System only works with Same Vendors Endpoints	System only works with Same Vendors Endpoints	System only works with Same Vendors Endpoints	Works with multiple carries of same technology (GSM, CDMA, LTE, WiMAX)	System only works with Same Vendors Endpoints
	Equipment Relocation		Equipment can be moved if necessary	Equipment can be moved if necessary	Cannot be relocated	Cannot be relocated	Can be Relocated	Very Difficult to Re-Locate
Recommended Solutions		**Licensed Tower and Unlicensed Mesh are good options!**	**Good selection (cost effective, very good performance)**	**Good selection (cost effective, very good performance in Shakopee Environment)**	**Shakopee Meters may be too Dense for this AMI solution, Water is a problem with this AMI Technology, More expensive**	**Water Meters are a problem with this AMI Technology and this option is Much More expensive**	**Water Meters are a problem with this AMI Technology and this option is Much More expensive**	**Water Meters are a problem with this AMI Technology and this option is Much More expensive**

Figure 23 - Summary of AMI Options for SGI Communications (Part 2 of 2)

KEY	
Green	Perferred Solution and Best Meets Requirements
Yellow	Optional Solution and Still Meets Requirements
Red	Least Preferred Solution and Doesn't Meet Requirements

Shakopee Public Utilities Preliminary Design

The two figures below show preliminary network designs for Shakopee Public Utilities and correlate to the Technology Options discussed in this Study.

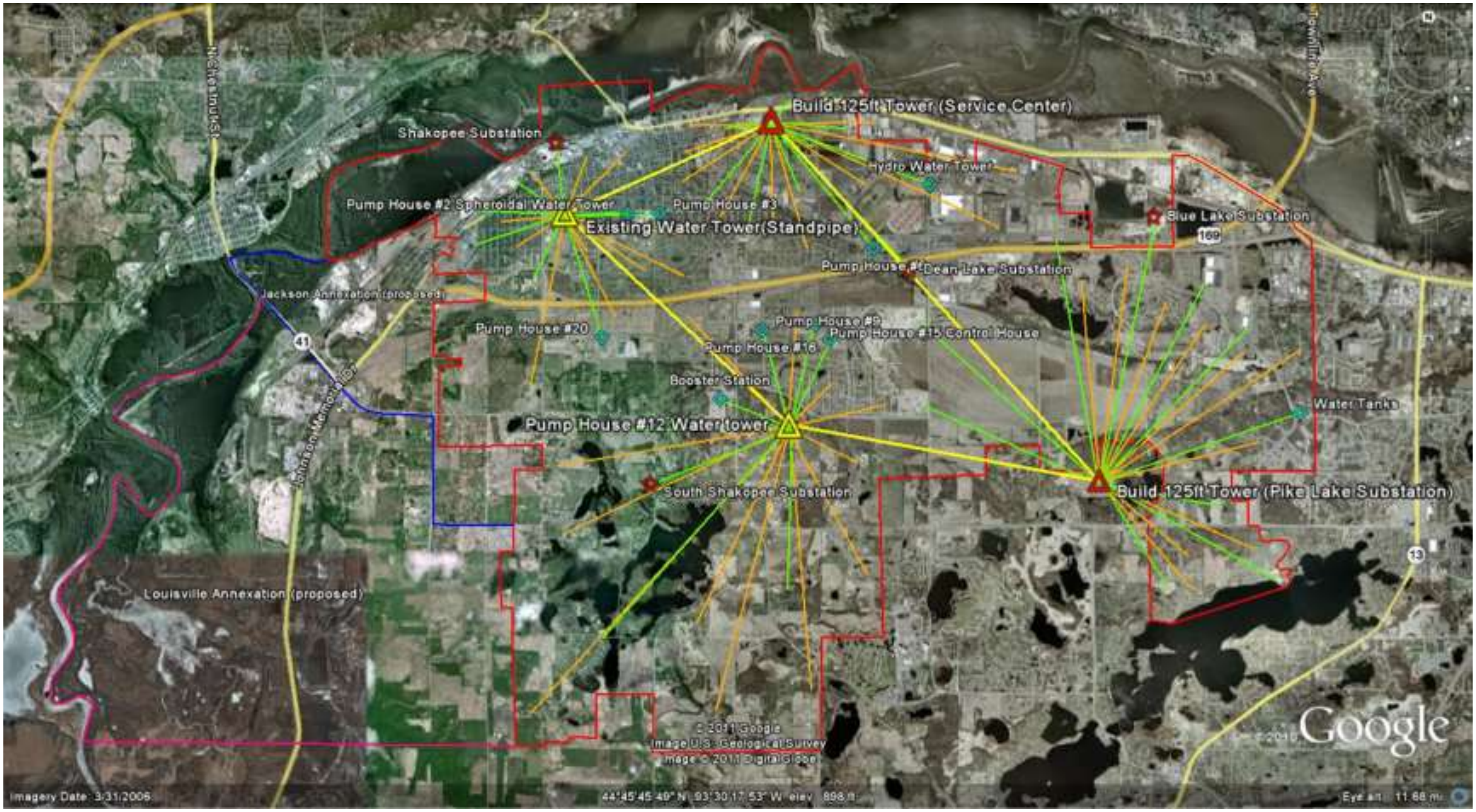
It is recommended that SPU utilize the existing Water Tanks; the Standpipe and the Dominion Avenue Water Tower, construct two towers at the Service Center and Pike Lake Substation, and create a microwave ring that will add redundancy to the network and provide at least 50 Mbps of data capacity.

To provide service to the Townships of Jackson and Louisville, an additional Communications Site will be required. In an effort to minimize cost we have selected a Transmission tower located high on a hill that will provide coverage to both townships and be added to the microwave ring. The new microwave ring will grow from four sites to five sites.

Shakopee Public Utilities would be required to construct two 125-foot towers at the Service Center and Pike Lake Substation. This Service Center would be the main front end for the network. A total of two water tanks would be utilized in the IP Backhaul Microwave network prior to annexation of the townships. Each of the four sites would have microwave dishes and equipment, Mid-Tier Backhaul Point to Multi-Point equipment and Licensed Tower AMI equipment and antennas. Those sites are highlighted in red and yellow on the map and the microwave ring is also in yellow.

The Mid-Tier Backhaul equipment is also at the Water Tanks and the Microwave site built at the Service Center. This equipment serves to tie in the RTUs located at the sub-stations, the field devices used for Distribution Automation and the devices located at the water facilities back to the IP Backhaul. These links are shown in a green color on the map.

The Licensed Tower AMI network also uses the Water Tanks and the Microwave site built at the Service Center. Each electric and water meter will communicate with base station equipment located at the Water Tanks. These links are shown in a caramel color on the map. There are only a few lines shown, as it was not feasible to show lines to thousands of meters.



City of Shakopee Service Territory
Proposed Township of Jackson Annexation
Proposed Township of Louisville Annexation
IP Backhaul Microwave Path
Mid-Tier Backhaul WiMax
AMI Solution

Figure 24 – SPUC Service Territory Network Design (without annexations)

City of Shakopee Service Territory
Proposed Township of Jackson Annexation
Proposed Township of Louisville Annexation
IP Backhaul Microwave Path
Mid-Tier Backhaul WiMax
AMI Solution

Figure 25 – SPUC Service Territory Network Design (with Annexations)

Core telecommunication and advanced metering infrastructure costs and benefits are shown on the following two tables below.

CORE TELECOMMUNICATIONS (INPUTS)							
SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	INPUT	FALSE	FALSE	FALSE	FALSE	FALSE	
Capital Costs	$ 1,619,410	$ -	$ -	$ -	$ -	$ -	$ 1,619,410
O&M Costs	$ 69,401	$ 162,528	$ 165,749	$ 169,067	$ 172,485	$ 212,838	$ 2,676,194
Total Costs	$ 1,688,811	$ 162,528	$ 165,749	$ 169,067	$ 172,485	$ 212,838	$ 4,295,604
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Hard and Soft (Costs) / Benefits	$ (1,688,811)	$ (162,528)	$ (165,749)	$ (169,067)	$ (172,485)	$ (212,838)	$ (4,295,604)
Net Present Value (NPV)	$ (3,410,858)						

Telecommunication Costs

The Telecommunication O&M costs of $2.676 million are categorized into three areas: 1) Additional internal labor costs of $1.584 million. This cost is for SPU to hire a new resource to maintain the telecommunications network; 2) annual software maintenance fees of $278,893 related to the new IP backbone and Mid-Tier back haul management systems; and, 3) additional O&M cost of $813,308 related to the new hardware that will be installed as a result of this build-out.

ADVANCED METERING INFRASTRUCTURE (AMI) (INPUTS)							
SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	INPUT	FALSE	FALSE	FALSE	FALSE	FALSE	
Capital Costs	$ 736,787	$ -	$ -	$ -	$ -	$ -	$ 736,787
O&M Costs	$ 54,906	$ 55,448	$ 56,007	$ 56,582	$ 57,174	$ 64,167	$ 888,618
Total Costs	$ 791,693	$ 55,448	$ 56,007	$ 56,582	$ 57,174	$ 64,167	$ 1,625,404
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ 14,412	$ 88,484	$ 147,473	$ 147,473	$ 147,473	$ 147,473	$ 2,020,041
Total Hard and Soft Benefits	$ 14,412	$ 88,484	$ 147,473	$ 147,473	$ 147,473	$ 147,473	$ 2,020,041
Net Hard and Soft (Costs) / Benefits	$ (777,281)	$ 33,035	$ 91,466	$ 90,891	$ 90,299	$ 83,305	$ 394,637
Net Present Value (NPV)	$ 66,913						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

AMI Costs

The AMI O&M costs of $888,618 and is related to annual software maintenance fees of AMI head end as well as costs associated with equipment out of warranty.

SMART METERS

General Discussion

Smart meters identify detailed consumption information and transfer it back to the utility for monitoring, customer data presentation, and billing purposes. Different models of smart meters are available for electric and water utilities. Some vendors offering Smart Meters are shown to the right. Meters that have an integrated communication card in them are the lowest cost solution. As most utilities choose this lower cost solution, the pricing for these types of meters were used in the Study. However, if SPU desires to purchase multiple vendor meters, the integrated communication card would not be acceptable and the cost would be a bit more expensive. This is a strategic decision that can be determined at or prior to the time an RFP is issued. It can also be included as a part of the RFP construct, allowing the decision to be made after the Vendor Proposals are returned for SPU analysis.

Figure 26 - Potential Smart Meter Vendors

The meters will be replaced at the rate of 20% in Year 1, and 40% in the following two years. Implementation at this rate allows for creation, issuance of required RFPs, and selection of vendors. The electric and water meters will be discussed separately below.

Electric Meter Replacement

Summary Information

SMART METERS - ELECTRIC (INPUTS)							
SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
ROADMAP	INPUT	INPUT	INPUT	FALSE	FALSE	FALSE	
Capital Costs	$ 522,748	$ 1,007,826	$ 992,970	$ 41,362	$ 46,073	$ 77,128	$ 3,293,911
O&M Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Costs	$ 522,748	$ 1,007,826	$ 992,970	$ 41,362	$ 46,073	$ 77,128	$ 3,293,911
Operational Benefits	$ 72,253	$ 221,134	$ 376,422	$ 549,661	$ 563,677	$ 748,146	$ 8,372,152
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ 72,253	$ 221,134	$ 376,422	$ 549,661	$ 563,677	$ 748,146	$ 8,372,152
Net Hard and Soft Benefits / (Costs)	$ (450,495)	$ (786,692)	$ (616,548)	$ 508,300	$ 517,604	$ 671,018	$ 5,078,242
Net Present Value (NPV)	$ 2,863,489						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

NUMBER OF ELECTRIC METERS	
Category	Input
Number of Residential Meters	14,627
Number of Poly Phase C&I meters	484
Number of Single Phase C&I meters	1,028
Number of Power Quality C&I meters	0
Number of Other C&I meters	0
Total Number of C&I meters	**1,512**
Total number of meters	**16,139**

Costs

The total capital costs of $3.293 million consist of smart meters (including installation). Growth rates for new electric meters were estimated to grow from 1% in the first year to up to 3% by Year 15, for an average growth rate of 2.3% for residential, single phase C&I poly phase C&I customers. The table below shows the growth rates used for each year. This growth rate represents an increase of 6,019 new residential meters over the course of 15 years; a 41% increase, which is considered to be a conservative increase over such a long duration of time.

Annual Growth Rate from Year 1 through Year 15														
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1.0%	1.3%	1.5%	1.7%	1.9%	2.1%	2.3%	2.5%	2.7%	2.9%	3.0%	3.0%	3.0%	3.0%	3.0%

Figure 27 - Annual Electric Customer Growth Rate over 15 Years

Electric smart meters will be installed in Years 1 through 3 in accordance with the roadmap. There are no additional O&M costs associated with the installation of electric smart meters.

Benefits

Operational Benefits

The operations benefits of $8.372 million over 15 years consist of the following elements:

- Increase in SPU's current electric meter revenue of 1.0% as a result of improved electric meter accuracy (SPU's current revenue for Residential and Single Phase C&I of $12.574 million and $465,301 respectively)
  - Residential of $2.044 million (replacement of current electromechanical meters with new Smart Meters)
  - Single Phase C&I of $66,000 (replacement of current electromechanical meters with new Smart Meters)
  - SPU currently has digital Poly Phase C&I meters that do not result in inaccurate meter readings, therefore replacing these meters with a Smart Meter will not increase the revenue accuracy
- Increase in SPU's current revenue of 0.5% as a result of early theft detection due to the tamper detection devices on the electric smart meters (SPU's current revenue for Residential and Single Phase C&I of $12.574 million and $465,301 respectively)
  - Residential of $1.022 million
  - Single Phase C&I of $33,000

  - Poly Phase C&I do not result in increased revenue as theft is normally not prevalent in this customer type
- Cost savings related to personnel and vehicle as truck rolls are avoided for customer disconnects and reconnects; these assumptions are based on incremental calculations and may over time not result in the full replacement trucks and / or personnel depending on other factors and realization of these assumptions as well as the re-utilization of these resources for other purposes
  - Labor savings of $2.096 million; This savings was calculated using the following method over 15 years:
    - There are approximately 2,280 disconnects / reconnects each year. Each disconnect / reconnect along with completing the necessary paperwork takes a Meter Reader approximately 1 hour. The average hourly loaded salary rate for a Meter Reader is $53 per hour (and escalates by salary increase of 3% per year for 15 years)
  - Vehicle savings $664,000; This savings was calculated using the following method over 15 years:
    - There are approximately 2,280 disconnects / reconnect each year. Each disconnect / reconnect requires a vehicle to be used. The cost of a vehicle associated with each disconnect / reconnect is $16.75 (and escalates by salary increase of 3% per year for 15 years).
- Cost savings associated with SPU not having to pay meter reader mileage cost to perform a meter readings is $107,640 over 15 years; this number is comprised of $3,000 per meter reader multiplied times 2.6 meter readers that are not needed as electric smart meters are installed.
- Labor savings of $2.338 million related to the reduction of 2.6 meter readers as meter readers are not needed as electric smart meters are installed.

Energy and Demand Benefits

There are no energy and demand benefits associated with the installation of electric smart meters.

Societal Benefits

There are no societal benefits associated with the installation of electric smart meters.

Water Meter Replacement

There are currently 10,648 residential and commercial water meters. The water distribution system is monitored via an Allen Bradley SCADA application. SPU has implemented a Sprinkler Program on odd and even days. SPU has found that neighbors typically keep each other honest. Nonetheless, if individuals do violate the program, there are fines applied.

SPU has been recently deploying the Sensus iPERL, a new concept in water metrology that provides accurate low flow measurements over time, high flow durability, and low maintenance needs. This result allows measurement of water that had otherwise passed through the system undetected. This type of water meter is shown in the figure below.

Figure 28 - Sensus iPERL Water Meter

One can make similar comparisons in accuracy to the Elster Smart Meter. SmartMeter range of AMR-enabled products incorporates no-moving-parts technology to deliver accuracy with intelligent metering features such as tariffs and event monitoring. It is recommended that an RFP be issued to ensure products and pricing can be obtained for the best price and performance.

We assumed that it requires about one hour to change out a water meter (for 3000 – 4000 meters). Additionally, we assumed that two-thirds of the 7,000 water meters are either Sensus or Neptune meters, which are ready for installation of the MIU (wireless operation). Otherwise, it requires gaining access in the homes to run wire from between the meters.

SMART METERS - WATER (INPUTS)

SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	INPUT	INPUT	INPUT	FALSE	FALSE	FALSE	
Capital Costs	$ 876,346	$ 841,112	$ 437,136	$ -	$ -	$ -	$ 2,154,594
O&M Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Costs	$ 876,346	$ 841,112	$ 437,136	$ -	$ -	$ -	$ 2,154,594
Operational Benefits	$ 40,446	$ 126,387	$ 218,751	$ 227,179	$ 235,944	$ 345,314	$ 3,774,454
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ 40,446	$ 126,387	$ 218,751	$ 227,179	$ 235,944	$ 345,314	$ 3,774,454
Net Hard and Soft (Costs) / Benefits	$ (835,900)	$ (714,725)	$ (218,385)	$ 227,179	$ 235,944	$ 345,314	$ 1,619,860
Net Present Value (NPV)	$ 566,296						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

NUMBER OF WATER METERS	
Category	Input
Number of Residential Water Meters	9,770
Number of Normal Capacity commerical meters	804
Number of Large Capacity commerical meters	74
Total Number of commerical meters	**878**
Total number of water meters	**10,648**

Costs

The Capital Costs of $2.155 million consist of smart water meters (including installation). A constant growth rate of 1.0% was used for residential, normal capacity commercial and large capacity commercial meters. Smart water meters will be installed in Years 1 – 3 in accordance with the roadmap. There are no additional O&M costs associated with the installation of smart water meters.

Benefits

Operational Benefits

The operations benefits of $3.774 million consist of following elements:

- Increase in metered gallons due to improved accuracy water meters; currently it is estimated that 4.5% of water losses are a result of unmetered gallons; This is due to older meters running slower that new meters and also inaccurate readings at very low water usage; it was assumed that all of these losses will be recovered through the use of Smart Water meters.
    - Residential and commercial - $3.588 million
- Decrease in leakage as a result of a Leakage detection program; currently it is estimated that 1.5% of water losses are a result of leakage; to be conservation it was estimated that 80% of these losses could be recovered as a result of use of Smart Water meters.
    - Residential and commercial - $186,332

Energy and Demand Benefits

There are no energy and demand benefits associated with the installation of water smart meters.

Societal Benefits

There are no societal benefits associated with the installation of water smart meters.

METER DATA MANAGEMENT SYSTEM (MDMS)

Meter Data Management System (MDMS) enables utilities to manage large volumes of meter data including but not limited to power factor information, voltage and VAR measurements, outage incident data, and theft data. Functionality of MDMS offerings vary widely and require detailed RFPs to be constructed that clearly define what is required. Prices were included to properly construct an RFP that contains functionality specific to SPU's requirements.

Figure 29 - Potential MDMS Vendors

At the low price end, Daffron & Associates, Inc., SPU's current provider of CIS and Financial software, purports to provide the ability to house Smart Meter data within their CIS^{iXp} software offering at approximately $100,000. Daffron's MDMS capabiliy is limited to providing customer viewing of their meter data via a web portal. There would be no integration to other SPU applications. If the only requirement SPU desires is for customers to view their consumption data on the Internet, this solution would be sufficient for SPU's needs.

Nonetheless, there exist commercial services such as DataRacker (see www.dataraker.com) that provide meter data analysis similar to that provided through a high-end MDMS application. There are other Vendors of a similar nature. The data analysis is conducted through cloud computing technology, i.e., the computer performing the analysis is not at SPU, but at the DataRaker facilities or elsewhere. This type of service is priced on a per meter per month basis.

Cloud computing solutions have built in security and redundancy in their network. This solution contains high-level security controls with a choice of IP connections to the platform and redundancy built into the environment to meet the security, performance, and reliability demands of enterprise systems.

Additional benefits can be achieved by adding corresponding functionality within the MDMS application. As one might imagine, more functionality adds more costs. To be conservative, a somewhat more robust MDMS was included in this Study. Also, by adding this more functional MDMS, there are more benefits that can be achieved. West Monroe Partners believes the additional functionality, with accompanying benefits, is a prudent choice. These types of functionalities would include, but is not limited to, the following:

- Realization of Business Intelligence – slice and dice the data to provide "information"
- Ability to detect theft and fraud through examining unusual usage patterns
- Ability to obtain customer feedback awareness

- Ability to edit and track editing of data
- Ability to better estimate bills
- Ability to utilize industry standard estimations
- Error handling abilities
- Auditing and validation abilities
- Aggregation abilities
- Reporting abilities
- Ability to forecast revenue

METER DATA MANAGEMENT SYSTEM (MDMS) (INPUTS)							
SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	INPUT	FALSE	FALSE	FALSE	FALSE	FALSE	
Capital Costs	$ 489,700	$ -	$ -	$ -	$ -	$ -	$ 489,700
O&M Costs	$ 15,000	$ 38,175	$ 38,870	$ 39,586	$ 40,324	$ 49,033	$ 620,976
Total Costs	$ 504,700	$ 38,175	$ 38,870	$ 39,586	$ 40,324	$ 49,033	$ 1,110,676
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Hard and Soft (Costs) / Benefits	$ (504,700)	$ (38,175)	$ (38,870)	$ (39,586)	$ (40,324)	$ (49,033)	$ (1,110,676)
Net Present Value (NPV)	$ (900,624)						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

Costs

The Capital Costs of $489,700 consist of the software cost of $150,000 in Year 1 in accordance with the roadmap and $339,700 in implementation costs. There are additional O&M costs of $620,976 associated with the installation of an MDMS. This is due to:

- Additional SPU labor costs for a database manager estimated to be $395,976 over a 15-year period
- Software maintenance fees of $225,000 over a 15-year period

Benefits

There were no benefits attributed to the MDMS, but benefits for functionality were accounted for in this Study in other areas. For instance, reduced theft was included in the electric and water smart meters.

Operational Benefits

There are no operations benefits associated with installation of an MDMS.

Energy and Demand Benefits

There are no energy and demand benefits associated with the installation of an MDMS.

Societal Benefits

There are no societal benefits associated with the installation of an MDMS.

SYSTEM INTEGRATION/ACCEPTANCE TESTING

System Integration can be accomplished by point-to-point integration or through creation of an Enterprise System Bus (ESB). The later requires the creation of a data dictionary defining the type of data will be passed between applications. In general, it is less costly over the entire software life cycle to utilize an ESB. It is particularly effective when existing applications are modified or upgraded.

For SPU, it is recommended to install an ESB for some, but not all of its SG software solutions outlined in this report. There is a point of diminishing returns when applications are installed that have very little integration requirements. Such applications would use the conventional point-to-point integration. Therefore, a mix of ESB and point-to-point integration is recommended. A point-to-point or ESB integration includes the following three phases:

- Design
- Implementation
- Testing

The Design phase consists of conducting workshops with SPU and the software vendors to determine the interface requirements. Depending on the system integration method, the technical system specifications are needed either before or after the workshops. These documents are critical in Implementation phase of integration. During this phase it is critical that the software vendors be on-site at SPU premise.

The next phase of this effort includes Implementation of the integration. This is where the integration team would perform the coding that meets the business and technical requirements gathered in the Design phase.

The final phase of the integration effort is the Testing phase. There are various types of testing that occur in this phase:

- **Strategy** – Determine the testing strategy, resources needed for testing and the deliverables associated with each testing type.
- **Unit Testing** – Consists of creating independent test scenarios and executing those scenarios to determine that the functionality exists as designed and as expected.
- **End to End Testing** – Consists of creating End to End test scenarios and executing those in a very closely orchestrated method. This phase of testing involves many areas within the organization as is the most important of all testing phases.
- **Acceptance Testing** – This phase of testing gets SPU involved in executing the key test scripts developed for the End to End testing. This will help the users get comfortable with the system and that the system in working as intended.

SYSTEM DESIGN, INTEGRATION AND TESTING (INPUTS)						
SUMMARY						
Category	Year 1	Year 2	Year 3	Year 4	Year 15	TOTAL
	INPUT	INPUT	INPUT	INPUT	FALSE	
Capital Costs	$ 744,500	$ 388,825	$ 73,902	$ 98,848	$ -	$ 1,306,075
O&M Costs	$ 31,800	$ 31,800	$ 31,800	$ 31,800	$ 65,833	$ 801,344
Total Costs	$ 776,300	$ 420,625	$ 105,702	$ 130,648	$ 65,833	$ 2,107,419
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ -	$ -	$ -	$ -	$ -	$ -
Net Hard and Soft (Costs) / Benefits	$ (776,300)	$ (420,625)	$ (105,702)	$ (130,648)	$ (65,833)	$ (2,107,419)
Net Present Value (NPV)	$ (1,765,829)					

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

Costs

The Capital Costs of $1.306 million consist of the hardware and software cost of $159,000 in Year 1 in accordance with the roadmap and $1.147 million in implementation costs (labor). The implementation costs consist of additional FTE for $56,000 and consulting costs of $1.090 million. The consulting costs consist of Design, Implementation and Testing phases. The Design phase involved defining the requirements of the integration. The Implementation phase consists of coding the integration based on those requirements and the Testing Phase consists of testing that integration to ensure they are working as intended. It is assumed that there will be 2 major systems (AMI head end and LCMS / MDMS) and 2 minor systems (CIS and OMS) to integration either to each other or the ESB. Each major system integration costs were estimated to have 25 messages associated with each system and an estimated 40 hours for each message. For the minor system integration it was estimated to have 10 messages associated with each system and an estimated 40 hours for each message. Therefore, the result of these calculations was: Design Phase- $335,000, Implementation Phase - $420,000 and Testing Phase - $335,000.

There are additional O&M costs of $801,344 associated with the on-going system design, integration and testing functions and annual system maintenance costs. These are:

- Additional SPU labor costs for a database manager estimated to be $324,344 over a 15-year period
- Hardware and software maintenance fees of $477,000 over a 15-year period

Benefits

There were no direct benefits attributed to the System Design, Integration and Testing function, but benefits were accounted for in this Study in other areas.

Operational Benefits

There are no operations benefits associated with the System Design, Integration and Testing function.

Energy and Demand Benefits

There are no energy and demand benefits associated with the System Design, Integration and Testing function.

Societal Benefits

There are no societal benefits associated with the System Design, Integration and Testing function.

GEOGRAPHIC INFORMATION SYSTEM (GIS)

The Geographic Information System (GIS) integrates hardware, software, and data for capturing, managing, analyzing, and displaying geographically referenced information. GIS enables utilities to enhance network maps and business information with weather intelligence, topography, rights-of-way, satellite imagery, line-clearing cycles, and field data. Typically, the GIS application is integrated into the other Smart Grid Elements to leverage the spatial component. It is also used during the electric and water Smart Meter rollout process. It would allow for SPU to strategically plan the rollout by the spatial component.

As many utilities commonly have done, SPU currently has implemented the ESRI GIS, beginning about six years ago. For reference purposes only, some competing vendors in this business area are shown on the right.

INTERGRAPH

ESRI

GIS Landmark

Figure 30 - Potential GIS Vendors

SPU currently has two licenses (seats) and plan to secure one more license to map water assets. They are in the process of cleaning up the data within the application. Rolling this out at SPU as a fully integrated solution is planned to be over four years. Below is a conceptual diagram of how GIS might be integrated to other SPU applications.

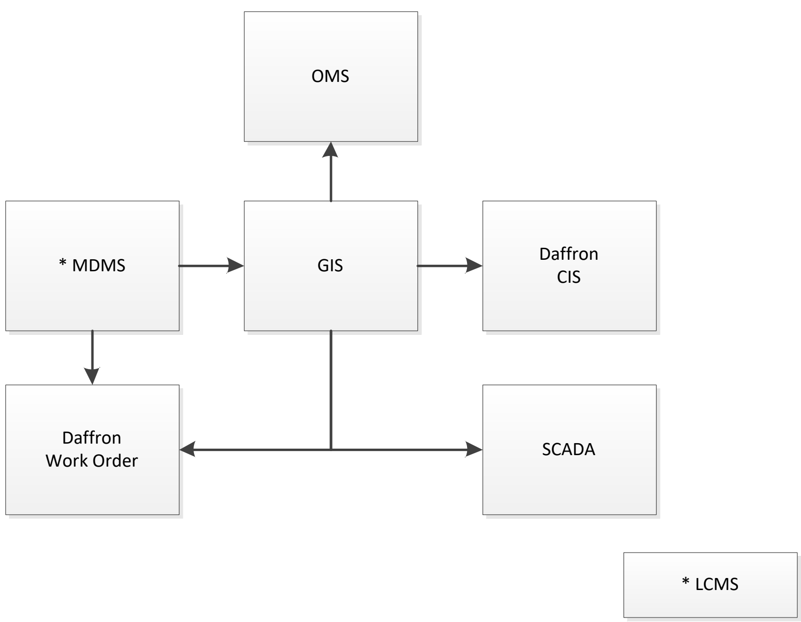


Figure 31 - Conceptual GIS Integrated Solution

GEOGRAPHIC INFORMATION SYSTEM (GIS) (INPUTS)							
SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	FALSE	INPUT	INPUT	INPUT	INPUT	FALSE	
Capital Costs	$ -	$ 156,737	$ 29,322	$ 29,752	$ 30,194	$ -	$ 307,775
O&M Costs	$ -	$ 2,000	$ 3,200	$ 4,400	$ 5,600	$ 28,420	$ 241,642
Total Costs	$ -	$ 158,737	$ 32,522	$ 34,152	$ 35,794	$ 28,420	$ 549,417
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Hard and Soft (Costs) / Benefits	$ -	$ (158,737)	$ (32,522)	$ (34,152)	$ (35,794)	$ (28,420)	$ (549,417)
Net Present Value (NPV)	$ (416,341)						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

Costs

The Capital Costs of $0.308 million consist of the hardware and software cost of $100,000 spread over Years 2 through 7, in accordance with the roadmap and $207,775 in implementation costs over that same timeframe. There are additional O&M costs of $241,642 associated with the GIS rollout and the associated annual system maintenance costs. These are as follows:

- Additional SPU labor costs (expensed) of $147,642 in Years 8 through 15, for a database manager that will spend 15% of their time maintaining and operating the GIS
- Hardware and software maintenance fees of $94,000 for the entire 15-year timeframe

Benefits

There were no direct benefits attributed to the GIS application.

Operational Benefits

There are no operations benefits associated with the GIS application.

Energy and Demand Benefits

There are no energy and demand benefits associated with the GIS application.

Societal Benefits

There are no societal benefits associated with the GIS application.

DISTRIBUTION AND SUBSTATION AUTOMATION (DA / SA)

Distribution Automation (DA) allows monitoring and control of feeders, reclosers, and switchgear to reduce outage durations and alleviate overload conditions. Substation Automation (SA) enables data acquisition and remote control of substations including capacitors and regulators on feeders. Automation of substations can allow utilities to manage, compare, and share non-operational data, enhance network security of real-time data, and perform multiple roles with the use of fewer devices.

Some vendors in this market space are shown to the right.

Figure 32 - Potential DA/SA Vendors

Automation systems also enable to measurement of power quality through voltage, power factor, and isolation transformers. DA and SA ensure maximum data security through access isolation, allowing only point-to-point transfers – zero data is transmitted via the internet. Despite this, bringing broadband IP for phone service, enterprise network, email, and maps will require additional security.

SPU is presently served through five distribution substations. They are noted below, with some associated points of interest.

- Shakopee Substation – 28 MVA – Four 12.5 kV distribution feeders
    - This substation was constructed in the 1960's
    - Xcel Energy owns the power transformers
    - There are single phase feeder regulators in the substation
    - This is an open air substation that is planned for replacement in 2013 with unitized substation equipment
    - The existing regulators are scheduled to be replaced, so costs for their replacement is considered to be common and not included in this Study
- Blue Lake Substation – 2-25 MVA transformers – Two 13.8 kV distribution feeders
    - This substation was constructed in 1979
    - Xcel Energy owns the power transformers
    - There are single phase feeder regulators in the substation
- South Shakopee Substation – 28 MVA – Two power transformers, nine 12.5 kV distribution feeders
    - Regulation is by LTC on both power transformers (without separate feeder regulation)

    - This is a unitized substation owned by SPU

- The first power transformer was installed in 1997
- The second power transformer was installed in 2008
- This substation does not have space for a third power transformer
- Dean Lake Substation – 47 MVA – Two power transformers, sixteen 13.8 kV distribution feeders
  - Regulation is by LTC on both power transformers (without separate feeder regulation)
  - This is a unitized substation owned by SPU
  - The first power transformer was installed in 1999
  - The second power transformer was installed in 2002
  - SPU is positioned to put another power transformer in this substation
- Pike Lake Substation – 47 MVA – One power transformer, five 13.8 kV distribution feeders
  - Regulation is by LTC on the power transformer (without separate feeder regulation)
  - This is a unitized substation owned by SPU
  - The first power transformer was installed in 2011

Regarding electric distribution automation, SPU currently has field ties between different voltage lines through a step-down regulator (13.8-12.5kV), permitting full feeder backup under single contingency outages. The SPU electric distribution system can be quantified as:

- 36 circuits (maximum); use 28 now (8 are reserved)
- 47 capacitor bank (total) (on 28 feeders)
- Average length of feeders is about three miles and are each loaded to about 50%
- There are over 300 Gang Operated Air Break (GOAB) switches on the overhead and underground distribution system

DISTRIBUTION AUTOMATION (DA) / SUBSTATION AUTOMATION (SA)
(INPUTS)

SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	FALSE	INPUT	INPUT	INPUT	INPUT	INPUT	
Capital Costs	$ -	$ 157,781	$ 157,781	$ 157,781	$ 110,447	$ 94,669	$ 1,577,812
O&M Costs	$ -	$ 5,260	$ 10,520	$ 15,780	$ 19,462	$ 52,599	$ 433,419
Total Costs	$ -	$ 163,041	$ 168,301	$ 173,561	$ 129,909	$ 147,268	$ 2,011,231
Operational Benefits	$ -	$ 2,277	$ 4,732	$ 7,404	$ 9,544	$ 42,060	$ 279,559
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ 3,502	$ 7,005	$ 10,507	$ 9,071	$ 21,015	$ 188,223
Total Hard and Soft Benefits	$ -	$ 5,779	$ 11,737	$ 17,911	$ 18,616	$ 63,075	$ 467,782
Net Hard and Soft (Costs) / Benefits	$ -	$ (157,262)	$ (156,564)	$ (155,650)	$ (111,293)	$ (84,193)	$ (1,543,449)
Net Present Value (NPV)	$ (1,119,643)						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

Costs

The Capital Costs of $1.578 million consist of the hardware and software cost spread over Years 2 through 15, in accordance with the roadmap. A higher percentage of capital investment is incurred in the early years to establish the necessary infrastructure to gain some immediate benefits. The capital investment for SA and DA are as follows:

- $117,000 in SA implementation costs, which consist of $17,000 in SCADA upgrades related to Substation Automation and 100,000 replacement costs for accelerated regulators.
- $1.461 million in DA Hardware and software costs, which includes the cost to install motors and remote control capability on the distribution feeder switches

There are additional O&M costs of $433,419 associated with the SA and DA rollout and the associated annual system maintenance costs. These are as follows:

- DA hardware and software maintenance fees of $361,113
- SA hardware and software maintenance fees of $72,306

Benefits

Operational Benefits

The Operational Benefits of $279,559 reflect reductions in crew costs estimated to be a 10% savings (or avoided future costs) for a one two-man crew due to better fault locations quantified in lower overtime costs of $245,635 over the 15 year period. Additionally, there is a small reduction in Customer Call Center costs of $33,924 due to few outage calls that will come into the Customer Call Center.

Energy and Demand Benefits

There are no energy and demand benefits associated with the DA and SA applications.

Societal Benefits

There are societal benefits amounting to $188,223 associated with the DA and SA applications. These are divided amongst the following three customer classifications.

- Average residential customer benefit per minute of $0.60 (based on EPRI study) results in a $11,330 savings from reduced outages
- Average single phase C&I customer benefit per minute of $25.00 (based on EPRI study) results in a $33,179 savings from reduced outages
- Average poly phase C&I customer benefit per minute of $260.00 (based on EPRI study) results in a $143,714 savings from reduced outages

DISTRIBUTION MANAGEMENT SYSTEM (DMS)

Distribution Management System (DMS) provides SCADA functionality on the distribution system to effectively integrate with other distribution components such as GIS. Benefits of DMS include real-time data acquisition and distribution automation. Some of the Vendors in this market area are shown on the right.

The DMS integrates into numerous utility applications, as shown in the figure below.

Figure 33 - Typical DSM Vendors

Typical benefits from a DMS are:

- Improved operational efficiency
- Reduction in outage durations
- Increased customer satisfaction
- Improved asset management decisions
- Information access in real-time
- Increased operational flexibility
- Quicker task transitions
- Enhanced fault tolerance
- Integration of existing information

Figure 34 - DSM Typical Benefits

At this point in time, a DMS is in its formative development stages. It was found to be very expensive in relation to benefits that might be derived. Integration costs are very high as well. Note the figure above in regard to the number of applications such a function might require integration when implementing. Therefore, it has been excluded for further examination within this Study.

West Monroe Partners recommends that SPU continue to monitor this application to seek technology or integration breakthroughs that might lower the costs associated with this Smart Grid Element.

OUTAGE MANAGEMENT SYSTEM (OMS)

An Outage Management System (OMS) classifies and identifies outage conditions for proper staffing and repair of fault conditions. OMS typically includes reporting, indexing, charting, and statistical analysis calculations of outage incidents. Some Vendors in this marketplace are shown to the right.

Figure 35 - Typical OMS Vendors

Integration with OMS is typically from the GIS application that provides spatial information of utility assets. Such electrical connectivity information, when linked with the CIS, will allow for many operating analysis procedures to occur. One can know where switches are located, which feeder segment a customer is located on, and when an Automatic Number Identification (ANI) is employed, customer calls link to CIS account information, which in turn links to GIS. This all results in knowing very quickly where a fault may have occurred on the system.

If SPU doubled in size, the existing operations staff would not be able to handle the outages. The bottom line is that if SPU wants to be able to maintain the customer outage (in minutes) per customer as low as it is today, an application of this operational functionality will be required.

OUTAGE MANAGEMENT SYSTEM (OMS)
(INPUTS)

SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	FALSE	FALSE	FALSE	INPUT	FALSE	FALSE	
Capital Costs	$ -	$ -	$ -	$ 438,652	$ -	$ -	$ 438,652
O&M Costs	$ -	$ -	$ -	$ 20,000	$ 20,000	$ 20,000	$ 240,000
Total Costs	$ -	$ -	$ -	$ 458,652	$ 20,000	$ 20,000	$ 678,652
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ -	$ -	$ 79,330	$ 79,330	$ 79,330	$ 951,964
Total Hard and Soft Benefits	$ -	$ -	$ -	$ 79,330	$ 79,330	$ 79,330	$ 951,964
Net Hard and Soft (Costs) / Benefits	$ -	$ -	$ -	$ (379,321)	$ 59,330	$ 59,330	$ 273,312
Net Present Value (NPV)	$ 106,247						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

Costs

The Capital Costs for OMS is $438,652, consisting of the hardware and software cost of $200,000 in Year 4, in accordance with the roadmap and $238,652 in implementation costs in Year 4. There are additional O&M costs of $240,000 associated with the annual system maintenance costs over a 15-year period.

Benefits

Operational Benefits

There are no operations benefits associated with the OMS application.

Energy and Demand Benefits

There is no energy and demand benefits associated with the OMS applications.

Societal Benefits

There are societal benefits amounting to $951,964 associated with the OMS applications. These are divided amongst the following three customer classifications.

- Average residential customer benefit per minute of $0.60 (based on EPRI study) results in a $695,618 savings from reduced outages
- Average single phase C&I customer benefit per minute of $25.00 (based on EPRI study) results in a $112,166 savings from reduced outages
- Average poly phase C&I customer benefit per minute of $260.00 (based on EPRI study)results in a $144,180 savings from reduced outages

LOAD CONTROL MANAGEMENT SYSTEM (LCMS)

The Load Control Management System (LCMS) provides direct control of customer load during high-load conditions or emergency system events based upon utility and customer preferences. LCMS enables a utility to lower the amount of equipment needed for generation and distribution and create an efficient load curve. Two Vendors in this marketplace are shown on the right.

Sometimes the ePortal application is included in the LCMS application. When this is combined there will be reduced integration costs and lower capital requirements. When SPU selects their LCMS, there will need to be a determination of several key factors; some of which are listed below.

- Is the LCMS for the "Utility", or will it be designed as "Customer" centric?
- Will the LCMS function as a Demand Response Management System (DRMS) only?
    - Push button to drop load.
    - Manage load on transformers by controlling load on the distribution feeders
- Will the ePortal be operationally functional (i.e., trigger load reduction)
- What is the platform the LCMS will be functioning?
- Are pricing signals to be passed to the customer?
- Is Demand Response signals to be passed to the customer?

LOAD CONTROL MANAGEMENT SYSTEM (LCMS)
(INPUT)

SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	FALSE	INPUT	FALSE	FALSE	FALSE	FALSE	
Capital Costs	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ 50,000
O&M Costs	$ -	$ 30,000	$ 30,900	$ 31,827	$ 32,782	$ 44,056	$ 512,590
Total Costs	$ -	$ 80,000	$ 30,900	$ 31,827	$ 32,782	$ 44,056	$ 562,590
Operational Benefits (Included with DSM Programs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits (Included with DSM Programs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits (Included with DSM Programs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Hard and Soft (Costs) / Benefits	$ -	$ (80,000)	$ (30,900)	$ (31,827)	$ (32,782)	$ (44,056)	$ (562,590)
Net Present Value (NPV)	$ (396,490)						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

Costs

The Capital Costs for LCMS is $50,000 consists of hardware and software cost of $50,000 in Year 2, in accordance with the roadmap. There are additional O&M costs of $512,590 associated with the annual system maintenance costs over a 15-year period.

Benefits

Operational Benefits

There are no operations benefits associated with the LCMS application.

Energy and Demand Benefits

There is no energy and demand benefits associated with the LCMS applications.

Societal Benefits

There are no societal benefits associated with the LCMS applications.

DEMAND SIDE MANAGEMENT (DSM)

There are nine DSM programs being considered in this study. Each program is briefly described in the below table and indicates the targeted customer type.

Program Name	Description of Program	Customer Type
ePortal	Provides ability to access consumption data in order to better manage energy use	Residential and Single Phase C&I
Prepay	Targeted to those customers that do not pay their electric bill on time and often get disconnected	Residential
Thermal Storage	Targeted to large customers and the utility will incentivize	Poly Phase C&I
Time-of-Use (TOU) /Critical Peak Pricing (CPP) *		All customers
Home Energy Device (HED) *		Residential and Single Phase C&I
Programmable Controlled Thermostat (PCT) *		Residential and Single Phase C&I
Load Control Relay (LCR) **		Poly Phase C&I
Load Control (Water Heater) *		Residential and Single Phase C&I
Load Control (AC) *		Residential and Single Phase C&I

* *These programs are embraced and effective when a customer this is offered with an option to be on a TOU rate*

** *This program can be offered to the Poly Phase C&I customers as either mandatory or optional*

A summary of the nine DSM Programs is provided in the table below. More details relative to each of the programs follow below.

DEMAND SIDE MANAGEMENT (DSM)
(INPUTS)

SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	FALSE	INPUT	INPUT	INPUT	FALSE	FALSE	
Capital Costs	$ -	$ 259,363	$ 79,407	$ 124,597	$ 133,256	$ 28,257	$ 1,042,849
O&M Costs	$ -	$ 106,732	$ 202,671	$ 220,849	$ 162,956	$ 199,549	$ 2,399,512
Total Costs	$ -	$ 366,095	$ 282,077	$ 345,446	$ 296,212	$ 227,806	$ 3,442,361
Operational Benefits	$ -	$ 41,443	$ 41,443	$ 41,443	$ 41,443	$ 41,443	$ 580,208
Energy / Demand Benefits	$ -	$ 16,436	$ 76,165	$ 172,092	$ 281,626	$ 1,600,111	$ 9,926,155
Societal Benefits	$ -	$ 1,305	$ 7,106	$ 16,725	$ 25,427	$ 133,508	$ 854,917
Total Hard and Soft Benefits	$ -	$ 59,184	$ 124,715	$ 230,260	$ 348,497	$ 1,775,062	$ 11,361,280
Net Hard and Soft (Costs) / Benefits	$ -	$ (306,911)	$ (157,362)	$ (115,186)	$ 52,285	$ 1,547,256	$ 7,918,919
Net Cost / (Benefit) NPV	$ 4,551,649						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

Costs

The Capital Costs of $1.043 million consists of hardware and software costs of $935,729 and additional labor costs of $107,120. The additional labor column captures 1) additional SPU resources needed to run these programs or 2) outside consultants to assist with designing and planning of these programs. In the above following table there are no additional SPU resources needed to run these DSM programs as the current SPU resources have the capacity to do this. However, the Prepaid Program requires outside consultant assistance in designing and planning of this program as SPU did not have the experience in this area. The various DSM Program's capital costs are shown in the table below.

DSM Program	Hardware and software costs	Additional Labor	Total Costs
ePortal	$50,000	$0	$50,000
Prepay Program	$100,000	$107,120 *(A)*	$207,120
Thermal Storage Program	$0	$0	$0
Time-of-Use (TOU)/Critical Peak Pricing (CPP)	$0	$0	$0
Home Energy Devices (HED)	$0	$0	$0
Programmable Controlled Thermostat (PCT)	$0	$0	$0
Load Control Relay	$25,717	$0	$25,717
Load Control (Water Heaters)	$325,291	$0	$325,291
Load Control (AC)	$434,721	$0	$434,721
Totals	**$935,729**	**$107,120**	**$1,042,849**

The O&M costs for each of the DSM Programs are shown in the table below. There is a total O&M cost of $2,399,512, consisting of $1,263,716 in increased annual system maintenance costs and $1,134,796 for a combination of program startup costs and rebates.

DSM Program	Other Costs	Increased System Maint. Costs	Total Costs
ePortal	$0	$829,764	$829,764
Prepay Program	$81,383	$434,952	$516,335
Thermal Storage Program	$530,000[1]	$0	$530,000
Time-of-Use (TOU)/Critical Peak Pricing (CPP)	$0	$0	$0
Home Energy Devices (HED)	$91,568[2]	$0	$91,568
Programmable Controlled Thermostat (PCT)	$224,845[3]	$0	$224,845
Load Control Relay	$18,000[4]	$0	$18,000
Load Control (Water Heaters)	$165,000[5]	$0	$165,000
Load Control (AC)	$24,000[6]	$0	$24,000
Totals	**$1,134,796**	**$1,263,716**	**$2,399,512**

Benefits

Operational Benefits

Only two of the DSM Programs provide operational benefits, the first being the ePortal by selling advertising space on the SPU website. The other item is the increase in uncollectable revenue when implementing the Prepay Program.

DSM Program	Advertising Revenue	Uncollectable Reduction	Total Benefits
ePortal	$145,600	$0	$145,600
Prepay Program	$0	$434,608	$434,608
Thermal Storage Program	$0	$0	$0
Time-of-Use (TOU)/Critical Peak Pricing (CPP)	$0	$0	$0
Home Energy Devices (HED)	$0	$0	$0
Programmable Controlled Thermostat (PCT)	$0	$0	$0
Load Control Relay	$0	$0	$0
Load Control (Water Heaters)	$0	$0	$0
Load Control (AC)	$0	$0	$0
Totals	**$145,600**	**$434,608**	**$580,208**

[1] Average Thermal Storage rebate of $7,500 per installation
[2] Offer Rebate of $50 per HED for the first 5-years
[3] Marketing Effort and establishing program
[4] Establish LCR Poly Phase Program
[5] Establish LCR Water Heater Program
[6] Heavily Promote the Program

Energy and Demand Benefits

There are energy and demand benefits associated with the creation of DSM Programs. The table below shows the benefits for each of the nine DSM Programs examined for SPU.

DSM Program	Purchased Energy Savings	Purchased Demand Savings	Total Benefits
ePortal	$1,230,542	$429,382	$1,659,924
Prepay Program	$379,774	$89,494	$469,268
Thermal Storage Program	$1,465,731	$301,198	$1,766, 929
Time-of-Use (TOU) / Critical Peak Pricing (CPP)	$0	$1,340,162	$1,340,162
Home Energy Devices (HED)	$887,152	$270,212	$1,157,364
Programmable Controlled Thermostat (PCT)	$502,973	$1,115,431	$1,618,404
Load Control Relay	$0	$577,228	$577,228
Load Control (Water Heaters)	$0	$340,073	$340,073
Load Control (AC)	$0	$996,802	$996,802
Totals	**$4,466,172**	**$5,459,982**	**$9,926,155**

Societal Benefits

There are societal benefits associated with the implementation of DSM Programs totals $854,917. This is based upon the following formula for saving Greenhouse Gases (GHG):

GHG $ Savings = ∑ ((0.7 tons of GHG Emissions/MWH) x (Annual MWH Saved) x ($20 per ton))

To be conservative, the $20 per ton of GHG was kept constant over the 15-year Study timeframe. This is based from IMEA (Illinois Municipal Electric Agency) Value of Carbon.

Rate of Penetration of DSM Programs

For each DSM Program there is an associated penetration rate that was derived from West Monroe Partner's past experience and industry accepted practice. The table below shows all of the values used for the various DSM Programs. Also, as some programs are not mandatory, and can be overridden at times, if the customer so chooses, there was a Realization Factor applied. Again, this was based upon West Monroe Partner's past experience.

The following tables present residential, single phase C&I, and the poly phase C&I customer class for the specified levels of: (1) penetration percentage; (2) energy reduction percentage; (3) demand reduction percentage; and (4) demand realization factor.

DEMAND SIDE MANAGEMENT (DSM) SCENARIO TABLES
(INPUT)

RESIDENTIAL CUSTOMERS

PENETRATION	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
EPORTAL Penetration	0%	2.0%	4.0%	6.0%	8.0%	9.5%	11.0%	12.5%	14.0%	15.5%	17.0%	18.5%	20.0%	21.5%	23.0%
HED Penetration	0%	1.0%	2.0%	4.0%	5.0%	6.0%	7.5%	9.0%	10.5%	12.0%	13.5%	15.0%	15.5%	16.0%	16.5%
LCR - Air Conditioning Penetration	0%	0.0%	1.0%	3.0%	5.0%	6.0%	7.0%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
LCR - Water Heater Penetration	0%	0.0%	1.0%	2.0%	3.0%	3.5%	5.0%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
PCT Penetration	0%	0.0%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
PREPAID Penetration	0%	0.5%	0.7%	0.9%	1.2%	1.4%	1.6%	1.8%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
TOU Penetration	0%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	12.0%	12.0%
ENERGY REDUCTION															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
EPORTAL: Reduction of ENERGY from ePortal per customer	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
HED: Reduction of ENERGY per customer	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
LCR - Air Conditioning: Reduction in ENERGY per customer	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LCR - Water Heaters: Reduction in ENERGY per customer	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
PCT: Reduction in ENERGY per customer	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Prepaid Program: Reduction of ENERGY per customer	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
TOU: Reduction of ENERGY per customer	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DEMAND REDUCTION															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
EPORTAL: Reduction of DEMAND from ePortal per customer	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	5%
HED: Reduction in DEMAND per customer	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	3%
LCR - Air Conditioning: Reduction in DEMAND per customer	35%	35%	34%	34%	33%	32%	32%	31%	30%	29%	29%	28%	27%	26%	25%
LCR - Water Heaters: Reduction in DEMAND per customer	15%	14%	14%	14%	14%	14%	13%	13%	13%	12%	12%	12%	11%	11%	11%
PCT: Reduction in DEMAND per customer	35%	35%	34%	34%	33%	32%	32%	31%	30%	29%	29%	28%	27%	26%	25%
Prepaid Program: Reduction of DEMAND per customer	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
TOU: Reduction in DEMAND per customer	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
DEMAND REALIZATION FACTOR															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
DEMAND Realization Factor - EPORTAL Program	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - HED Program	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - LCR Program (Air Conditioning)	50%	60%	75%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - LCR Program (Water Heaters)	50%	60%	75%	85%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - PCT Program	60%	70%	80%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - Prepaid Program	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - TOU Program	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

SINGLE PHASE C&I CUSTOMERS															
PENETRATION															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
EPORTAL Penetration	0%	2.0%	4.0%	6.0%	8.0%	9.5%	11.0%	12.5%	14.0%	15.5%	17.0%	18.5%	20.0%	21.5%	23.0%
HED Penetration	0%	1.0%	2.5%	4.0%	5.5%	7.0%	8.5%	10.0%	11.5%	13.0%	14.5%	16.0%	17.5%	19.0%	20.5%
LCR - Air Conditioning Penetration	0%	0.0%	1.0%	3.0%	5.0%	6.0%	7.0%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
LCR - Water Heater Penetration	0%	0.0%	1.0%	2.0%	3.0%	3.5%	5.0%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
PCT Penetration	0%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
TOU Penetration	0%	1%	3%	5%	7%	9%	9.5%	10.0%	10.5%	11.0%	11.5%	12%	12%	12%	12%
ENERGY REDUCTION															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
EPORTAL: Reduction of ENERGY from ePortal per customer	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
HED: Reduction of ENERGY per customer	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
LCR - Air Conditioning: Reduction in ENERGY per customer	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LCR - Water Heaters: Reduction in ENERGY per customer	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
PCT: Reduction in ENERGY per customer	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
TOU: Reduction of ENERGY per customer	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DEMAND REDUCTION															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
EPORTAL: Reduction of DEMAND from ePortal per customer	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
HED: Reduction in DEMAND per customer	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LCR - Air Conditioning: Reduction in DEMAND per customer	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
LCR - Water Heaters: Reduction in DEMAND per customer	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
PCT: Reduction in DEMAND per customer	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
TOU: Reduction in DEMAND per customer	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
DEMAND REALIZATION FACTOR															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
DEMAND Realization Factor - EPORTAL Program	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - HED Program	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - LCR Program (Air Conditioning)	50%	60%	75%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - LCR Program (Water Heaters)	50%	60%	75%	85%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - PCT Program	60%	70%	80%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - TOU Program	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

C&I POLY PHASE CUSTOMERS															
PENETRATION															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
LCR Program Penetration	0.0%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Thermal Storage Penetration	0.0%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	7.5%	8.0%	8.5%	9.0%	9.5%	10.0%	10.5%
TOU: Penetration	0.0%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	10.0%	10.0%	10.0%	10.0%
ENERGY REDUCTION															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
LCR Program: Reduction in ENERGY per customer	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Thermal Storage Program: Reduction in ENERGY per	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
TOU: Reduction in ENERGY per customer	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
DEMAND REDUCTION															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
LCR Program: Reduction in DEMAND per Customer	5.0%	5.0%	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Thermal Storage Program: Reduction in Summer DEMAND per customer	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%
Thermal Storage Program: Reduction in DEMAND for Shoulder Months around Summer per customer	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%
TOU: Reduction in DEMAND per Customer	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
DEMAND REALIZATION FACTOR															
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
DEMAND Realization Factor - LCR Program	50%	60%	75%	90%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - Thermal Storage Program	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
DEMAND Realization Factor - TOU Program	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

An additional manner of examining the energy and demand savings is shown in the table below. It provides a summary of demand savings during the summer and winter timeframes, as demand costs vary during these different periods.

DEMAND REDUCTION (kW)							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	Total
Total Residential Demand Reduction - Winter (kW)	-	289	1,729	4,130	6,841	35,166	N/A
Total Residential Demand Reduction - Summer (kW)	-	240	1,780	5,093	9,448	38,157	N/A
Total Single Phase C&I Demand Reduction - Winter (kW)	-	25	133	283	442	2,468	N/A
Total Single Phase C&I Demand Reduction - Summer (kW)	-	22	140	366	659	2,809	N/A
Total Poly Phase C&I Demand Reduction - Winter (kW)	-	181	543	997	1,567	6,998	N/A
Total Poly Phase C&I Demand Reduction - Summer (kW)	-	175	541	1,005	1,574	7,007	N/A
Total Demand Savings (kW)	-	933	4,867	11,874	20,531	92,605	N/A

DEMAND SAVINGS ($'s)							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	Total
Total Residential Demand Reduction - Winter	$ -	$ 2,091	$ 12,771	$ 31,121	$ 52,574	$ 329,450	$ 1,963,033
Total Residential Demand Reduction - Summer	$ -	$ 2,256	$ 17,037	$ 49,721	$ 94,083	$ 463,192	$ 3,053,910
Total Single Phase C&I Demand Reduction - Winter	$ -	$ 184	$ 985	$ 2,131	$ 3,395	$ 23,120	$ 129,440
Total Single Phase C&I Demand Reduction - Summer	$ -	$ 203	$ 1,337	$ 3,575	$ 6,566	$ 34,095	$ 213,302
Total Poly Phase C&I Demand Reduction - Winter	$ -	$ 1,465	$ 4,433	$ 8,160	$ 12,941	$ 69,291	$ 491,080
Total Poly Phase C&I Demand Reduction - Summer	$ -	$ 1,648	$ 4,986	$ 9,190	$ 14,596	$ 78,311	$ 555,288
Total Demand Savings	$ -	$ 7,847	$ 41,549	$ 103,899	$ 184,154	$ 997,459	$ 6,406,053

Figure 36 - Demand Reduction and Demand Savings

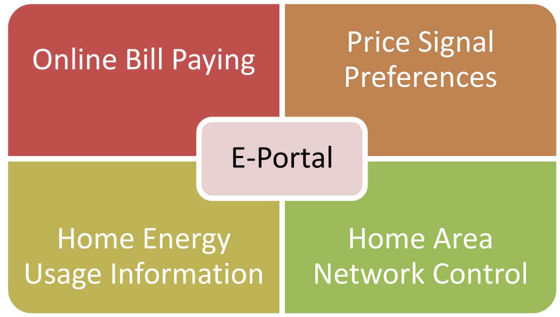
ENERGY REDUCTION (kWh)							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	Total
Total Residential Energy Reduction (kWh)	-	87,058	471,838	1,112,132	1,691,782	8,781,798	56,628,915
Total Single Phase C&I Energy Reduction (kWh)	-	6,127	35,763	82,488	124,462	754,477	4,436,598
Total Poly Phase C&I Energy Reduction (kWh)	-	-	-	-	-	-	-
Total Energy Reduction (kWh)	-	93,185	507,601	1,194,621	1,816,244	9,536,275	61,065,513

ENERGY REDUCTION ($'s)							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	Total
Total Residential Energy Reduction ($'s)	$ -	$ 3,944	$ 22,767	$ 54,091	$ 84,258	$ 539,322	$ 3,202,093
Total Single Phase C&I Energy Reduction ($'s)	$ -	$ 278	$ 1,726	$ 4,012	$ 6,199	$ 46,335	$ 251,655
Total Poly Phase C&I Energy Reduction ($'s)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Energy Reduction ($'s)	$ -	$ 4,222	$ 24,492	$ 58,103	$ 90,457	$ 585,657	$ 3,453,748

Figure 37 - Energy Reduction and Energy Savings

ePortal Application

Some of the functions provided to the customers through implementation of an ePortal are shown on the right and include self service capability, modify price signal notification preferences, see energy usage information and update Home Area Network (HAN) preferences from anywhere with internet access. A utility's interactive website can be modified to achieve greater functionality or an ePortal can be created as a separate, stand-alone system.



Introduction of the ePortal to residential customers has been shown to achieve a 5% energy reduction and a 2% demand reduction. This reduction in energy and demand was used for this Study.

Prepay Programs

The Prepay Program will be introduced in Year 2 to those residential customers that are having difficulty paying their electric bill on time and may have experienced being turned off for non-payment frequently. Others may wish to be placed on the Prepay Program at their option.

The primary drawback to a prepaid electricity program is the risk of disconnection for the consumer. Customers are relegated to making more frequent payments to their electricity account. Increased frequency and complexity leaves additional margin for human error. What was once a low-cost solution and risk mitigation strategy for the utility now becomes a poor use of human capital through sending technicians to customers for reconnections. That is why this program is coupled with a remote disconnect device.

There may be a societal stigma associated with prepaid programs that could cause potential conflict between customers and the utility. However, the value of a Prepay Program has been historically proven, resulting in a continued reduction of energy consumption by 20%. However, to be conservative, a 15% reduction in energy consumption was used for the purposes of this Study.

Finally, it will be necessary for SPU to further examine the regulations in Minnesota related to turning a customer off through a remote disconnect for non-payment during cold weather conditions.

Thermal Energy Program

Thermal energy storage tanks can store renewable energy in the form of ice for use during peak demand periods. Reducing the peak electric demand using thermal energy storage can cut cooling costs 20-40%, source energy and emissions are reduced and construction of new power plants and transmission lines can be delayed.

Southern tier states experience higher cooling demands, with full storage requirement installations cost competitive. For the upper Midwest, it is more economical to size the ice storage capacity to one-third of total requirements. As an example, consider a new commercial building with a calculated cooling design load of 1,200 ton (which is typically calculated at 20% over actual calculations). The GSA standards specify that three units are installed for diversity in the event of system failure. Therefore, three 400 ton units would be installed by the HVAC contractor. This means an economical installation for the upper Midwest would be to install two conventional 400 ton chillers and one 400 ton thermal energy storage device.

For new construction it is estimated that a 2-4 year payback is achieved, while replacement installations typically experience a 7-year payback period. This is due to the need to install a new plate-frame heat exchanger that can utilize glycol as the heat transfer medium. Note that when conducting the economic analysis for replacement systems, one assumes that the existing system will require replacement. In the event the existing system is functional and sized for the total cooling demand, the payback period is over 10-years.

Resistance to thermal storage installations comes from the mechanical engineers, as they want to specify the lowest cost of implementation, not the lowest total cost of ownership. The owners and architects generally understand the combined realization of both installation and operating costs over the lifetime of the system.

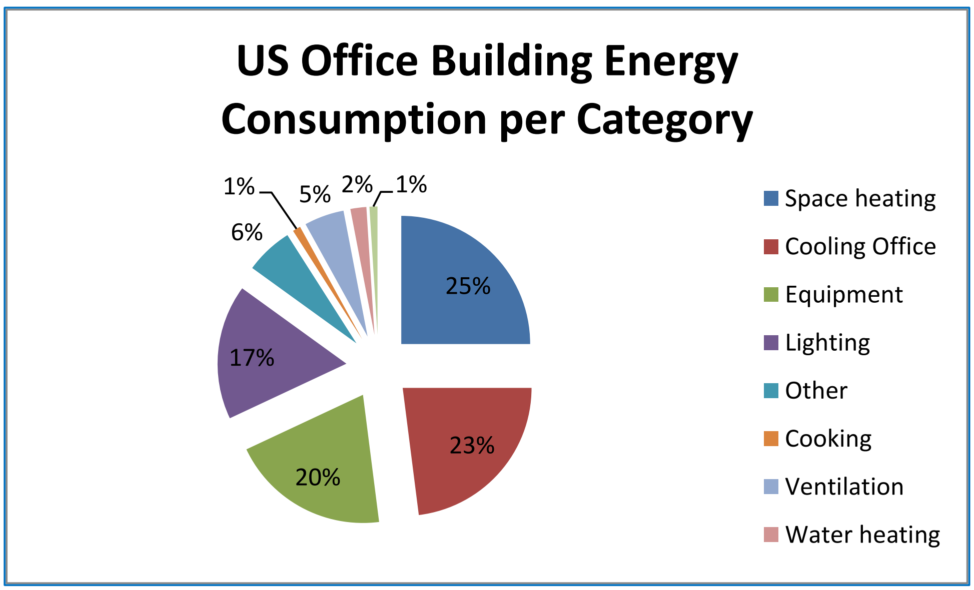


Figure 38 - Average US Office Building Energy Consumption

The figure to the right illustrates the typical energy consumption as a percent of total annual energy experienced by office building in the continental US. Office Buildings in the U.S. use an average of 17 kWh of electricity and 32 cubic feet of natural gas per square foot annually.[7] In an average office building in the United States, lighting, heating, and cooling represent about 65 percent of total energy use, making

[7] Source: E SOURCE Companies LLC

those systems the obvious targets for energy management savings. Energy represents about 19 percent of total expenditures for the typical office building.

The value received by the utility and its customer will vary upon the season. In the summer months, about 35% of the cooling load can be shifted to off-peak periods by utilizing thermal storage composing one-third of the cooling system. During the “shoulder-months” occurring in the spring and the fall seasons, the entire cooling load can be shifted to off-peak. This is illustrated in the figure below.

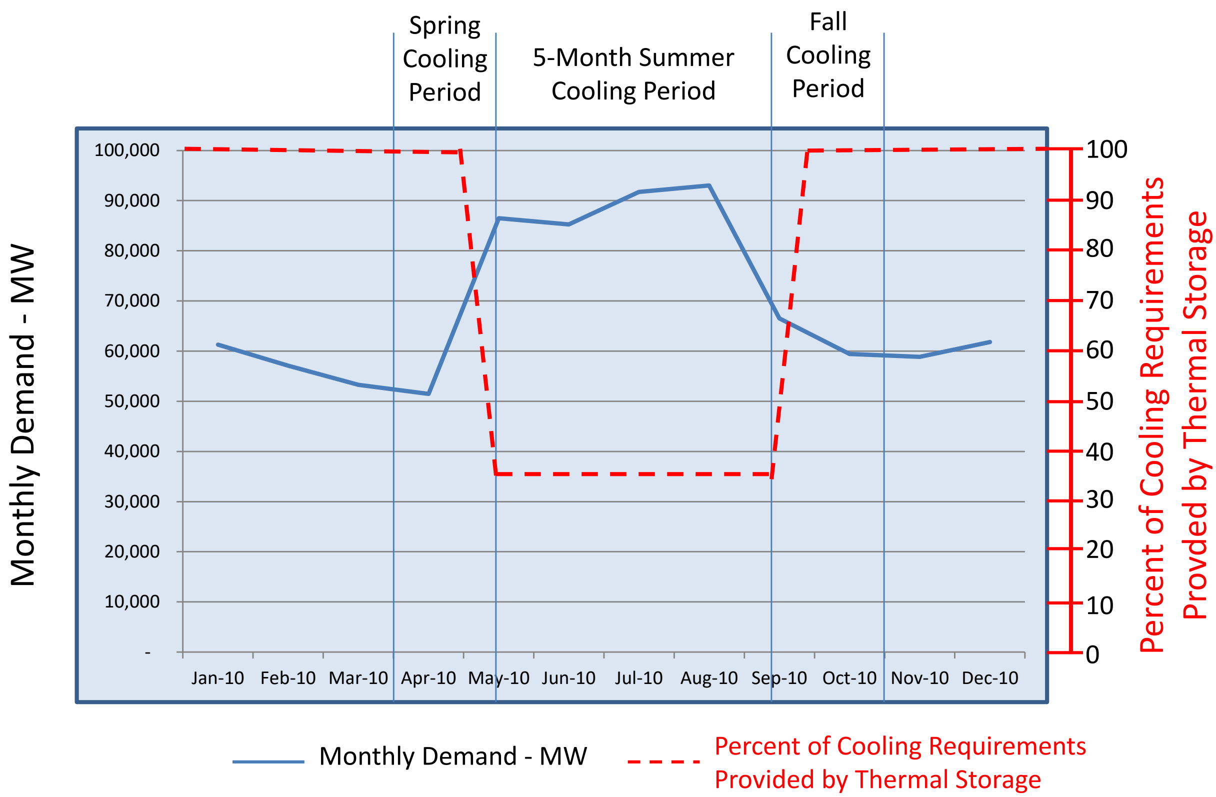


Figure 39 - Demand Curve with % of Cooling Requirements Provided from Thermal Storage

The percent of demand that can be shifted annually is derived to be 10%. The table below outlines the methodology used to calculate this demand shift amount to the off-peak. The model assumes an allocation of total cooling needs over the entire year, which is multiplied by 23% (the average cooling percentage for Office Buildings in the US). Further, the thermal storage installations will satisfy a certain level of total cooling demand for each month. This is multiplied for each month and summed to determine the total amount of annual demand that can be shifted to off-peak.

Table 2 - Methodology to Calculate Demand Shift for Thermal Storage

Month	% of Annual Cooling Needs	% Spread of total cooling load reduction	% of Thermal Storage	Winter % of Total Annual kW Transferred Off-Peak	Summer % of Total Annual kW Transferred Off-Peak	Annual % of Total Demand Shifted
Jan	0%	0.00%	100%	0.00%		
Feb	0%	0.00%	100%	0.00%		
Mar	1%	0.23%	100%	0.23%		
Apr	5%	1.15%	100%	1.15%		
May	8%	1.84%	50%		0.92%	
Jun	15%	3.45%	35%		1.21%	
Jul	27%	6.21%	35%		2.17%	
Aug	28%	6.44%	35%		2.25%	
Sep	10%	2.30%	35%		0.81%	
Oct	5%	1.15%	100%	1.15%		
Nov	1%	0.23%	100%	0.23%		
Dec	0%	0.00%	100%	0.00%		
Total	100%	23%		2.76%	7.36%	10.12%

Typically, a utility will experience a summer and winter demand charge. The amount of demand shifted will be more in the summer (higher demand cost period) season than during the winter. The table above indicates a five month summer period, in which 7.36% of demand can be shifted.

Not all poly phase C&I load consists of office buildings. Instead, they may have large process loads that operate continuously or possibly seasonally. Therefore, to be conservative, the demand and energy reductions were estimated at only 25% of the calculated amounts above.

Time of Use Rates (TOU) / Critical Peak Pricing Rates (CPP)

Time-of-Use (TOU) and Critical Peak Pricing (CPP) rate structures enable effective demand response that encourages load shifting and behavioral change to decrease peak demand. TOU prices are set for a specific time period on an advance or forward basis. Prices for energy consumed during these periods are predetermined by the utility and allow customers to vary their usage in response to set prices and manage their energy costs by shifting usage to a lower cost period. CPP is used in conjunction with TOU pricing and for certain peak periods where prices may inflate to account for generation costs and/or increased wholesale electricity levels.

As an introduction of the TOU rate to SPU customers, it is recommended that it be designed as revenue neutral. This means that the total annual revenue collected per customer classification remains the same. Then, as you move forward in time, the rates may be modified to better reflect SPU's real cost of energy. The concept is to provide incentives to your customers for reducing on-peak power consumption and/or moving the consumption to off-peak periods. The TOU / CPP program is targeted for all customer types and will be rolled out in Year 2.

Home Energy Device (HED) Program

A Home Energy Device (HED) is a mobile tablet or countertop display that monitors whole-household energy consumption. An HED provides a simple dashboard of relevant usage data for the consumer. By pinpointing specific areas of the home or appliances, consumers will become more aware of energy saving techniques and can adjust habits accordingly.

The HED program is targeted for residential and single phase C&I customers and will be rollout out in Year 3 – 4, with 75% in Year 3 and the remaining 25% in Year 4.

Programmable Controlled Thermostat (PCT) Program

The purpose of Programmable Controlled Thermostats (PCT) is to enable customers to customize in-home or in-facility heating and cooling levels that are dependent upon the time of day or season. When used appropriately, PCTs can reduce demand during time periods when customers are away from home or traveling. Energy saving regimes are typically automated and result in lower utility bills for customers.

The PCT program as proposed in this Study targets the residential and single phase C&I customers and will be rollout out in Year 3 – 4, with 75% in Year 3 and the remaining 25% in Year 4.

Load Control Program – Poly Phase C&I Customers

The Load Control Program for the Poly Phase C&I Customers that are served by SPU will have a remote-access capable switch installed on their premise that will serve to drop customer load when SPU seeks to reduce their peak demand curve. These are devices typically found in large processes which have the flexibility to be curtailed. Operations that can shift production to shoulder or off-peak times will be able to benefit financially through incentives offered by SPU.

The Load Control Program for poly phase C&I customers will be rollout out in Year 2.

Load Control Program – Water Heater

SPU has the ability to implement a promotional water heater program. The off-peak margin increases by $0.0244 per kWh. Some fraction of this increased margin can be used to incentivize customers to replace older natural gas water heaters with new electric water heaters.

Such a marketing program would show the Total Cost of Ownership (the installed price of the water heater plus the lifetime cost of electric energy) versus the higher cost for natural gas water heaters.

A combination of electric water heaters and TOU or off-peak rates can create a valuable money-saving solution for SPU’s customers. Controls on heaters can be used to remotely shut them off and control capabilities exist that permits, with customer approval, a utility to operate the water heater when it is the most economical for both the SPU and its customer. Tools such as targeted marketing, rebates, and educational sessions can be used to encourage customers to purchase the most appropriate water heater.

The Water Heater Load Control Program is targeted for residential and single phase C&I customers and is planned to be rolled out in Year 3 – 4, with 75% in Year 3 and the remaining 25% in Year 4.

Load Control Program – Air Conditioning

Under the Load Control Air Conditioning Program, SPU would install a remote-access capable switch on the air compressor of the air conditioning units of customers who elect to participate in this load control program. This program is already underway at SPU, however additional funding of $24,000 was provided in this Business Case to promote this program.

Enabled units will have shorter “on” cycle times that will reduce on-peak demand. As discussed earlier with the electric water heater program, the utility should distribute educational material and rebates to attract customer participation. Customers should also be given a schedule of when and how their AC unit will be affected. For example:

Choose the cycling option best suited for you

The 50% option

Time: Weekdays (excluding holidays), 11 a.m. to 8 p.m.

Unit cycles off: Maximum of 15 minutes every half hour (if needed).

You receive: $5 credit/month per household, June 1 through September 30.

The total credit will be $20.

100% option

If someone in your household is home during most of the day or has a medical condition this option is not recommended.

Time: Weekdays (excluding holidays), 11 a.m. to 8 p.m.

Unit cycles off: One continuous 3-hour period during any weekday (if needed).

You receive: $10 credit/month per household, June 1 through September 30.

The total credit will be $40.

Figure 40- LCR program Detail (Example ONLY)

The Air Conditioning Load Control Program is targeted for residential and single phase C&I customers and will be rollout out in Year 3 – 4, with 75% in Year 3 and the remaining 25% in Year 4.

Additional Demand Side Management Programs

There are two other DSM Programs that are mentioned below. The first, OPower is just recently being used by SPU. The second program is defined as a “Prescriptive Rebate Program” and has not been budgeted within this Study, but is provided to frame in a “catch-all” DSM Program for the C&I customers.

OPower

OPower, a third party service, provides a home energy report that is currently being used to inform SPU electric customers on a quarterly basis of their energy consumption relative to comparable customers. OPower employs behavioral insights to help utilities communicate more effectively with their customers. Studies support the fact that, Americans who receive meter data on their home energy use reduce consumption on average by 1.8 percent after the first year.

Since use of this program is outside of the scope of this Study, it is only mentioned for informational use. There has been no further study on this service.

Prescriptive Rebate Program

A successful Prescriptive Rebate Program (PRP) will leverage the following information obtained in the Smart Grid Business Case in order to target the appropriate DR technologies for SPU's customer sectors:

- **Demand Reduction Targets/Benefits:** Assess the demand reduction targets amount and likely benefits to be derived from SPU's perspective. The benefits will largely depend on peak demand costs ($/kW) that SPU projects to pay going forward, less any customer demand charges.
- **Demand Reduction Technologies/Applications:** Evaluate sector-specific technologies/applications that will have the most cost-effective demand reduction to SPU. The SPU team will need to assess the following data/factors in its analysis:

  <u>Societal</u>
  - Demographic information (including age, income, population growth, energy usage trends, demand planning)
  - Facility size
  - Leading indicators for economic growth as well as zoning and planning projections (predicted future loads on the system)

  <u>Technical</u>
  - Demand Realization Factor
  - Percent Demand Reduction
  - Seasonality impacts

  <u>Financial</u>
  - Override functionality
  - Added O&M Costs
  - Customer event energy reduction (revenue loss)

These factors will allow SPU to determine the targeted technologies/applications desired. Currently SPU does have programs in place for solar, wind and geothermal, as well as a load curtailment program, however, some general examples of demand reduction technology/programs are shown in the table below.

DSM Program	Definition	Common Applications / Technologies	
		Residential	Commercial and Industrial

Energy Efficiency	Any sponsored or subsidized program by which customers can contribute to reducing energy consumption through the purchase of, or material improvements to, an energy-consuming device.	Weatherization (insulation / reflective roofs / efficient window upgrades); Window Film / Screens; Duct Repair / Sealing; High-efficiency HVAC upgrades; Thermal Energy Storage; evaporative cooing; solar thermal; geoexchange; Efficient Indoor Lighting / sensors.	*In addition to residential applications*: Variable speed motors / pumps; Absorption chillers; Efficient Compressed Air Systems; chilled beams; thermal displacement ventilation.
Renewable Energy Generation	Any sponsored or subsidized program by which customers directly or indirectly consume / generate a "qualifying" fuel source for electricity.	Solar PV; wind turbines (micro, vertical axis)	Solar PV; wind turbines; biomass; geothermal; biofuels; small hydro
Non-Renewable Distributed Energy Generation	Any sponsored or subsidized program by which customers directly or indirectly consume / generate a "non-qualifying" fuel source for electricity.	Micro-CHP (gas or oil); electric only generators	CHP systems (micro- or large); electric only generators; waste-to-energy systems; wastes energy recovery
Alternative Rates	Any program where the utility provides an incentive to customers for shifting their energy consumption. This could include incentive rates for net metering and distributed generation.	Behavioral (multiple)	Behavioral (multiple)
Demand Response	Any program where a utility or transmission operator initiates a measure to control peak demand and the cost of purchased energy.	Direct load control (duty cycling / thermostat overrides); Voluntary Load Management; Pricing Signals	*In addition to residential applications*: Standby Generation; Interruptible Service (curtailing)

Two Key Steps to Managing the Prescriptive Rebate Program

1. Establish the utility rebate amounts/structures

Once the costs/benefits of demand reduction to SPU and the enabling technology/applications are evaluated, SPU will need to prescribe rebate incentives by technology and reduction capabilities to their customers. These rebate incentives can be universal, or established by reduction (kW) tiers and by sector type.

SPU will need to evaluate the rebate structures for their customers. The program size, sectors, and customer culture will need to be considered when determining the rebate architecture. Common, yet differing, demand reduction rebates include:

A. Upfront rebate payments (with or without 'claw-back' provisions, which requires a dollar amount be given back to the utility depending on certain circumstances)
   <u>Pros</u>: Provides customer with financial assistance in demand reduction investments
   <u>Con</u>: Utility funds 'at risk' for successful implementation and commissioning

B. Standard Performance Contract rebates for an established term of demand reductions once operational
   <u>Pro</u>: Provides utility assurance that demand reduction measures are met
   <u>Con</u>: Customer participation may be reduced, as incentive funds are not provided up front

2. Leverage existing SPU rebate programs

SPU already has a variety of rebate programs offers commercial, industrial, and residential customer incentives for the purchase and installation of qualifying energy efficient products. SPU will need to incorporate the successful elements of the rebate programs into demand reduction incentive programs.

Key Terms and Conditions to be adopted into demand reduction rebates forms:

- Effective date and program end date (with depletion of funds clause)
- Primary use in a residence with an active meter receiving SPU electric services
- Minimum performance requirements
- Double-dipping provisions/rebate amount caps
- Right to inspect the installation premises or request additional documentation
- Right to modify, amend or terminate the program without prior notice

CUSTOMER INFORMATION SYSTEM (CIS)

A Customer Information System (CIS) allows advanced pricing programs, provides information for new Demand Response programs, and captures a broad range of customer information within a single application. Customer information can include location, service, assets, and financial data.

SPU has purchased CIS, Financials and Materials software from Daffron & Associates, Inc. They are currently using the iXp version of Financials and Materials (*in test*), but still using the legacy version of CIS. The total estimated costs for Shakopee to upgrade to CIS iXp is estimated at under $70,000. Additional costs could be incurred if more training or custom programming is needed. These costs would be billed at Time and Material.

Additional products that Daffron has available that Shakopee would need to purchase for their Meter Data Management are shown in the following table. The costs are product costs. Some additional costs would be incurred for Project management and training, as needed.

Product	Used For	Price	Works with CIS-legacy	Works with CIS^{iXp}
ToolBox	AMI Integration	$10,000	X	X
ToolBox - additional web services	Other Integration	$2,000 per web service bus	X	X
e-Business	Customer Portal - to view bill history, usage, pay bill, etc.	$5,000 set-up fee plus $250 - $750 monthly fee	X	X
Daily Reads	Host Customer Daily Reads in CIS	$5,000	X	Included in iXp
Prepaid Metering	Bill and manage prepaid metering accounts	$5,000	X	Included in iXp
Net Metering	Bill and manage generation accounts	$5,000	X	Included in iXp

SPU has experienced some obstacles when upgrading a recent financial module of Daffron's application suite. Yet, the old CIS green screen application will someday require upgrading to the newer technology; or technology provided by another vendor. As in all software selections, it is recommended that SPU exercise due diligence in selecting their CIS solution.

Since CIS is currently budgeted for an upgrade, no dollars were provided in this study with respect to upgrading CIS. However, there were funds provided to integrate CIS to other applications. Additionally, all costs associated with other offerings from Daffron were not used in this Study. Rather, costs from WMP's past Smart Grid implementations were used to ensure the most conservative estimates were applied.

ELECTRIC VEHICLES / PLUG-IN HYBRID ELECTRIC VEHICLES (EV/PHEV)

Electric Vehicles are anticipated to have a significant impact on the electric grid over the next decade. This is a program being incentivized by the federal government. While load incurred from this particular "appliance" remains an unknown, it must be planned for before it happens. The most important thing SPU can do at this time is to devise a rate that will incent the EV/PHEV owners to charge their vehicles during off-peak periods. The additional load has the potential of overloading existing transformers. If there is a change of many of the transformers, the costs could be significantly large.

ELECTRIC VEHICLES (EV) / PLUG-IN HYBRID VEHICLES (PHEV)
(INPUTS)

SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	FALSE	FALSE	FALSE	INPUT	INPUT	FALSE	
Capital Costs	$ -	$ -	$ -	$ 85,842	$ 85,901	$ -	$ 343,729
O&M Costs	$ -	$ -	$ -	$ 18,000	$ 18,000	$ 20,723	$ 235,686
Total Costs	$ -	$ -	$ -	$ 103,842	$ 103,901	$ 20,723	$ 579,414
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ -	$ 726	$ 2,036	$ 36,904	$ 156,757
Societal Benefits	$ -	$ -	$ -	$ 28,290	$ 63,785	$ 829,985	$ 3,585,449
Total Hard and Soft Benefits	$ -	$ -	$ -	$ 29,016	$ 65,821	$ 866,889	$ 3,742,206
Net Hard and Soft (Costs) / Benefits	$ -	$ -	$ -	$ (74,826)	$ (38,080)	$ 846,166	$ 3,162,792
Net Present Value (NPV)	$ 1,782,572						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

Costs

The capital cost for EV / PHEV is $343,729, which consist of $265,500 to upgrade existing systems to accommodate charging stations, $70,000 for additional hardware/software, and $8,229 annually for labor requirements. The O&M costs of $235,686 consist of $216,000 in annual cost for secure communications and $19,686 for on-going labor costs.

Benefits

Operational Benefits

There are no operational benefits associated this area.

Energy and Demand Benefits

The energy and demand benefits associated with this area are $156,757 over 15 years.

Societal Benefits

The societal benefits associated with this area are $3.585 million over 15 years. This consists of $42,832 in savings related to Green House Gas (GHG) emission. In addition, there are customer savings of $3.542 million related to purchase of electricity (difference between Peak and Non-Peak) versus gas for their vehicles.

CALL CENTER OPERATIONS

The Customer Call Center, which now is comprised of two Customer Service Representative and various backups during busy times, answers incoming customer calls. As the Smart Grid Elements are installed, there will be additional customer inquiries. These will range from inquisitive questions about what it is all about, to questions seeking how to use the web portal information. Billing questions may also increase if customers feel their bills have gone up due to all of the capital investment being made by SPU.

In general, there will be about a 30% increase in call volume for the first year of Smart Meter installation. The Smart Meters are being installed over a three year period, with 20% in Year 1, and 40% for each Year 2 and Year 3. The cost was included to hire temporary help to move SPU through those three years when call volume is anticipated to increase. The positive aspect of this is that the calls do subside and history has shown that they actually reduce from current levels experienced by SPU.

GENERAL, FINANCE AND CALL CENTER (INPUTS)							
SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
Capital Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M Costs	$ 32,365	$ 64,730	$ 64,730	$ -	$ -	$ -	$ 161,824
Total Costs	$ 32,365	$ 64,730	$ 64,730	$ -	$ -	$ -	$ 161,824
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Hard and Soft (Cost) / Benefits	$ (32,365)	$ (64,730)	$ (64,730)	$ -	$ -	$ -	$ (161,824)
Net Present Value (NPV)	$ (146,969)						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

Costs

There are additional call center costs of $161,824 associated with the increase in customer call volume the year in which the customer comes onto AMI. These costs are incurred in the Year 1 – 3 when the Smart Meters are being installed.

Benefits

Operational Benefits

There are no operational benefits associated this area.

Energy and Demand Benefits

There are no energy and demand benefits associated with this area.

Societal Benefits

There are no societal benefits associated with this area.

CONSERVATION VOLTAGE REGULATION (DVC / CVR)

Conservation Voltage Reduction (CVR) provides flat voltage profile on feeders to reduce demand and energy through control and optimal placement of capacitors, regulators, and LTCs along the distribution and transmission lines. Direct Voltage Control (DVC) is the manual predecessor of CVR. It is recommended to first implement DVC practices in the manual format, then move to implementation of CVR by automating the DVC practices.

The table below shows the costs and benefits of installing DVC. This Study provides for 25% of the rollout to occur in Year 1 and 75% in Year 2.

DIRECT VOLTAGE CONTROL (DVC)
(INPUT)

SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	INPUT	INPUT	FALSE	FALSE	FALSE	FALSE	
Capital Costs	$ 187,200	$ 96,408	$ -	$ -	$ -	$ -	$ 283,608
O&M Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Costs	$ 187,200	$ 96,408	$ -	$ -	$ -	$ -	$ 283,608
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ 49,786	$ 204,545	$ 106,159	$ -	$ -	$ -	$ 360,491
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ 49,786	$ 204,545	$ 106,159	$ -	$ -	$ -	$ 360,491
Net Hard and Soft(Costs) / Benefits	$ (137,414)	$ 108,137	$ 106,159	$ -	$ -	$ -	$ 76,883
Net Present Value (NPV)	$ 60,555						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

The table below shows the costs and benefits of installing CVR. This Study provides for 50% of the rollout to occur in Year 3 and 50% in Year 4.

CONSERVATION VOLTAGE CONTROL (CVR)
(INPUT)

SUMMARY							
Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 15	TOTAL
	FALSE	FALSE	INPUT	INPUT	FALSE	FALSE	
Capital Costs	$ -	$ -	$ 706,784	$ 318,113	$ -	$ -	$ 1,024,898
O&M Costs	$ -	$ -	$ 425	$ 850	$ 31,801	$ 42,446	$ 407,045
Total Costs	$ -	$ -	$ 707,209	$ 318,963	$ 31,801	$ 42,446	$ 1,431,943
Operational Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy / Demand Benefits	$ -	$ -	$ 380,264	$ 781,178	$ 812,465	$ 1,295,034	$ 12,409,158
Societal Benefits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hard and Soft Benefits	$ -	$ -	$ 380,264	$ 781,178	$ 812,465	$ 1,295,034	$ 12,409,158
Net Hard and Soft (Costs) / Benefits	$ -	$ -	$ (326,945)	$ 462,214	$ 780,663	$ 1,252,587	$ 10,977,215
Net Present Value (NPV)	$ 7,001,256						

KEY	
INPUT	Imlementation Year
FALSE	Non-Implementation Year

The following provides more detail about the DVC/CVR applications.

Direct Voltage Control

Introduction

Power quality and energy losses are two important aspects of delivering electrical energy by utilities to their customers. Electric Utilities follow specific power quality guidelines for system voltage levels, voltage flicker, and other parameters. Energy losses occur when transporting power over the electrical system, which begins with generation losses, and continues through voltage transformations, transmission lines, distribution lines, and the secondary drops to the customer premise.

Losses within the energy delivery system directly correlate to the resistance of the system. Typically, the resistance of the system increases when the circuit is long and the wire is small. The smaller diameter conductors have more resistance. Resistance produces heat (thermal loading), which further limits the system's ability to effectively transport power. As a result of higher resistance, power "quality" is degraded.

In the United States the allowed operating service range for utilities is governed by the local Public Service Commissions or the utility's service guidelines. The IEEE voltage standards are typically adhered to as the standard throughout the US. This prescribed operating voltage for power companies is an operating range of +/-5% of 120 volts, or 114 to 126 volts.

To counteract voltage degradation, utilities generally maintain voltage levels close to the power source, i.e., the substation, at a high level, generally delivering a nominal voltage level to the first customer at 126 volts. Subsequently, this provides adequate voltage levels to customers at the end of the distribution line.

Voltage Reduction Reduces Demand

While the electrical distribution system is operated within the nominal range of 114 volts to 126 volts; electrical motors and equipment are generally rated to operate at +/- 10% of 115 volts, or 104.5 to 126.5 volts. Some devices function more efficiently, actually consuming less power, when operating at the lower voltage range. If a utility is able to lower the voltage such that a higher percentage of the equipment operates within its designed voltage range, the net effect is a "reduction" in overall power consumption. Lower power consumption results in lower losses on the distribution system.

Consider a distribution feeder of maximum length having customer load evenly distributed, with the source voltage set at 126 volts and the end voltage measuring 114 volts. This means roughly half of the devices on that feeder operate above the intended voltage and half below. Those devices operating at the higher voltage levels consume energy beyond what is actually needed to do work. Controlling the voltage throughout the feeder length, such that most of the devices operate near the lower end of the nominal level will reduce overall energy consumption, resulting in lower demand on the system. The figure below illustrates this concept.

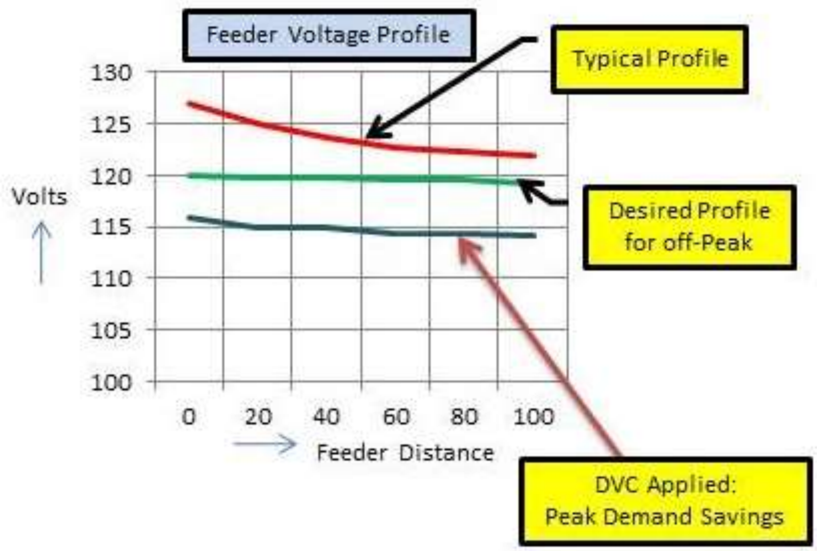


Figure 41 - Lower Voltage Results in Demand Savings

Definitions

Capacitor Bank

Capacitors are used to balance reactive power requirements on the electric system. Due to the device characteristics, a capacitor can provide indirect voltage regulation for areas primarily upstream from the unit and voltage regulation for areas downstream. The voltage regulation is in the form of a voltage increase. This device can also impact the power transformer's load tap changer's ability to regulate voltage. Power Engineers at utilities carefully size and locate capacitor banks to minimize voltage flicker and negative impacts to system control.

Direct Voltage Control (DVC)

DVC is a manual method of adjusting the distribution feeder voltage to reduce individual consumption of energy and therefore decrease the collective energy requirements for an area or a region within the electric service provider's service territory.

Conservation Voltage Reduction (CVR)

Method used to automatically adjust and monitor voltage to consumers to reduce individual consumption of energy and collective system requirements

Regulator

A device installed at a substation or along a feeder used to regulate (increase or decrease) the service voltage along a feeder. Regulators will only affect the portion of the system to which they are installed. This may include:

a. Entire substation bus

b. Individual Feeder
c. A portion of a feeder

Substation Transformer Load Tap Changer (LTC)

A device used to boost or buck (reduce) the system bus voltage at an electric substation. The increase or decrease affects all feeders served from or tied to the specific bus involved.

Advanced Metering Infrastructure (AMI)

A collection of devices will help optimize the energy (or other resource like water or gas) usage measuring, billing process, and consumer information/communication process.

Automatic Meter Reading (AMR)

A device (or devices) that help automate the meter reading process or obtain resource usage information remotely.

Minimal System Requirements

Direct Voltage Control (DVC)

1. Ability to manually control system voltage through distributed devices including:
   a. Substation Devices:
      - Substation Transformer LTC
      - Substation Bus Regulator
      - Substation Feeder Regulator
   b. Distribution Line installed regulators
   c. Capacitor banks
2. Method to Monitor Voltage at Consumer Premises (particularly at expected worst case scenario locations)

Conservation Voltage Reduction (CVR)

1. Elements from DVC
2. Additional technology for process automation:
   a. System Monitors
   b. Advanced Telecommunications Options
   c. Automated Controls (for equipment listed and to dynamically determine system adjustments and corrections)

Basic Information Requirements for Voltage Control Options

1. Power Purchase Agreement contractual terms – financial penalties, benefits, credits, etc.
2. Process for forecasting peak day(s) and peak time(s)
   a. Demand history for multiple years (at least five)
   b. Determination of consecutive or likelihood for future peaks

3. Identify Conditions Likely to Produce a "Peak Load" Day:
    a. Temperature
    b. Humidity
    c. Other Parameters?
4. System Inventory:
    a. Substations
    b. Busses
    c. Transformers
    d. Voltage Control Equipment at Substation
    e. Number of Feeders
    f. Ability to Modify?
    g. Line Capacitors
    h. Line Regulators
    i. What portion(s) of system are automated?
    j. System Monitoring Equipment Deployed (voltage verification)
5. System Standards (and their effect on DVC success):
    a. Conductor Size (affects rate of voltage decay)
    b. Number of Feeders per Bus (affects rate of voltage decay)
    c. Types of Loads on Each Feeder (affects ability to control entire bus)
    d. Typical Length of Feeder (disparately different lengths limits control opportunity)
    e. Feeder Construction Type (symmetrical arrangement of conductors like armless triangular has a voltage regulation effect while others like cross arm construction may have a detrimental effect on voltage)
6. Study Expected Results through System Model
    a. Is system model accurate?
    b. How does lack of accuracy (if any) affect the expected results?
7. Verification of Proper Operation
    a. Create process for control implementation
    b. Process to verify manual adjustment is successful in reducing voltage
    c. Process to verify reduction – (compare adjacent days) – savings "demonstration" and benefit quantification/validation
    d. Process to address alarms and needed adjustments
8. Create Process for Identifying and Implementing Operational Exceptions
    a. Do some feeders need to be "exceptioned" out? – critical or important loads

Advanced Requirements for Automated Voltage Control (CVR)

1. Review Technology Needs for Automation
2. Specify Technology Characteristics that Best Fit Clients Existing and Future Systems
3. Evaluate Current Solutions in the Market
4. Develop Integration Plan for Technology into existing and new systems – IT, Telecom, etc.

Benefits of Early DVC Implementation

1. Low implementation costs – try to take advantage of existing system
2. Ability to step into CVR over time
3. Possibility of capturing up to 60% of total CVR benefits
    a. assumes all peak demand days are forecasted
    b. assumes only reduction of demand during peak

Benefits of Transition to CVR

1. Optimized control and automation allowing for more dynamic and tighter control targets to maximize returns
2. Further reduced feeder losses (increased savings)
3. Reduced bulk energy purchases through demand reduction (decreased costs)

The model below illustrates the applications to be integrated for full benefits to be realized.

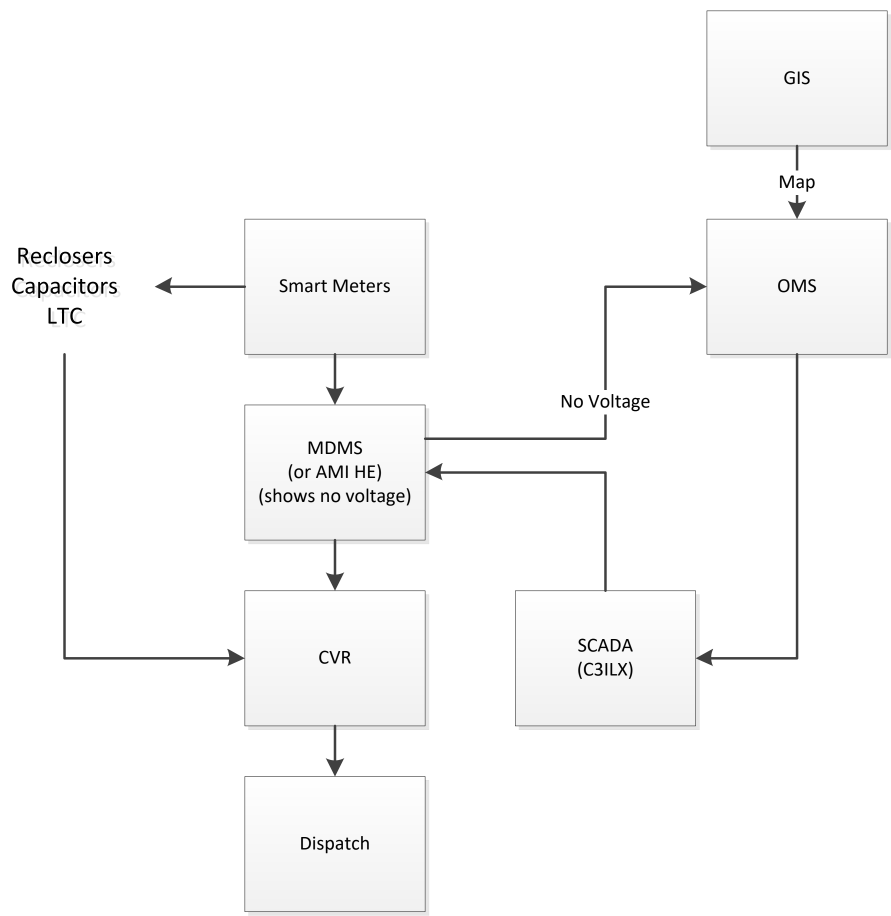


Figure 42 – Smart Grid High Level Integration Diagram

MOBILE DATA WORKFORCE (MWF)

Integration to Work Order System would be required for implementation of mobile dispatching through a mobile data workforce application. Additionally, there would likely need to be integration to GIS to provide a replacement for the feeder maps in the trucks.

Background Information

An automated MWF was examined based upon the following information relative to SPU operations. The interest is to utilize MWF with GIS to deliver distribution maps and work orders to the trucks.

- Water personnel use NextTel PTT, but only 3 people for electric
- There is one dispatcher for 8 hours for electric and water
- The CSR responds to customer calls. And there's a service for after hours
- They have 1 electric, and 1 water person on call, both with crews as backup, if needed

Requirements for automation to enable MWF:

1. Add PCs, and Automatic Vehicle Location (AVL) in all 35 vehicles
2. Determine the cost of AVL integration to GIS as well
3. Put in broadband wireless modems and private Wi-Fi in vehicles
4. Include outdoor Wi-Fi in service Yards and by all backbone locations
5. Need mobile VPN solution
6. The benefit of the WFMS is reduction of future employees due to growth

Due to the current size of SPU, including the number of crews and trucks, the number of meters, the number of outages (SAIDI and CAIFI are excellent), it was decided not to include MWF in the Smart Grid Business Case and Technology Roadmap, as utilities using such an application would serve about 150,000 customers or more.

ENTERPRISE ASSET MANAGEMENT SYSTEM (EAM)

The Enterprise Asset Management System (EAM) coordinates enterprise asset information to enable adequate service coverage with minimum capital and expense. In a utility, EAM refers to the overall management of departments, districts, infrastructure, equipment, and facilities.

SPU currently has about $90 million of Fixed Assets, with about 90% of this data on spreadsheets. The SPU audit firm is satisfied with the manner in which SPU manages their assets. Therefore, this Smart Grid Element will be excluded from the Smart Grid Business Case Study.