City of Columbia

701 East Broadway, Columbia, Missouri 65201

Agenda Item Number: REP 54-14
Department Source: Water & Light
To: City Council
From: City Manager & Staff
Council Meeting Date: June 2, 2014
Re: Smart Grid Study

Documents Included With This Agenda Item

Council memo
Supporting documentation includes: Reports

Executive Summary

Water & Light contracted with Burns & McDonnell to perform a Smart Grid Study. The purpose of this study is to help guide Columbia Water and Light (CWL) in determining which Smart Grid strategies are best suited for CWL. For the project, Burns & McDonnell focused on the potential integration of Smart Grid technologies into the existing CWL electric system. The documents Included with this Smart Grid Study from Burns & McDonnell are The Missouri Public Service Commission's Smart Grid Report, and Water & Light Staff Recommendations and Implementation Plan.

Discussion

There are many definitions for smart grid, some functional, some technological, and some benefits-oriented. Elements common to most is the application of digital processing and communications to the power grid. Data flow and information management are central to the smart grid. There are three (3) documents included with this report:

1) Burns & McDonnell, Smart Grid Business Case - Assist CWL in the assessment, feasibility and value of these types of investments and technologies on the CWL system.
2) Missouri Public Service Commission, Smart Grid Report - Provides a status update on various Smart Grid opportunities in Missouri and to present issues and concerns related to Smart Grid deployment.
3) Water & Light Staff, Smart Grid Recommendations and Implementation Plan - Intended to discuss and make recommendations to address the individual report conclusions.

These included documents will be referenced and used to guide future plans and budget requests for the development of CWL Smart Grid.

City of Columbia

701 East Broadway, Columbia, Missouri 65201

Fiscal Impact

Short-Term Impact: NA
Long-Term Impact: NA

Vision, Strategic & Comprehensive Plan Impact

Vision Impact: Not Applicable
Strategic Plan Impact: Not Applicable
Comprehensive Plan Impact: Not Applicable

Suggested Council Action

Accept Report

Legislative History

4/9/14 Submitted to Water & Light Advisory Board

Department Approved

City Manager Approved

City of Columbia
701 East Broadway, Columbia, Missouri 65201

SUPPORTING DOCUMENTS INCLUDED WITH THIS AGENDA ITEM ARE AS FOLLOWS:

Reports

Smart Grid

Water & Light Staff

Recommendations and Implementation Plan

Table of Contents

Introduction and Purpose

In June of 2013 Burns & McDonnell finished and delivered their "Smart Grid Business Case". The purpose of this business case study is to help guide Columbia Water and Light (CWL) in determining which Smart Grid components and implementation strategies are best suited for CWL. For the project, Burns & McDonnell focused on the potential integration of Smart Grid technologies into the existing CWL electric system.

Using the 2013 Smart Grid Business Case and other Department studies, assessments and documents staff has developed this CWL Staff Recommendations and Implementation Plan. This document is intended to discuss and make recommendations to address the individual report conclusions in Section 6.0 of the 2013 Smart Grid Business Case.

Burns and McDonnell Observations

Return on Investment:

Direct financial payback to CWL within 15 years is not expected from a comprehensive investment in smart grid technology upgrades. Estimated ROI results are variable due to some uncertainty in overall upgrade costs and the resulting benefit values (and the ability to monetize them).

Staff Comments:

- Staff recognizes that there may be other non-financial benefits. This could include better response time to outages, improved reliability and other customer based benefits.

Customer Acceptance:

Smart grid upgrades have the potential to provide CWL customers with significant benefits in the form of increased availability of information, increased service reliability, and bill savings opportunities. However, it is unclear if the CWL customer base would embrace and capitalize on these opportunities, if offered.

Staff Comments:

- In the 2014 Customer Satisfaction Survey results show that new customer metering was rated most useful by Residential customers for the following purposes:
    - More easily detecting power outages with an Net Positive Index of 113 and the modal score (most often selected) being a 5
    - Comprehensive electric consumption data with an NPI of 107
    - Remotely connecting and disconnecting service with an NPI of 96.

- Staff recommends that the results of this survey serve as a baseline/benchmark for future surveys to track attitudinal changes.
- Staff recommends creating a pilot program for Commercial and Industrial (C&I) customers which would allow the customer to expand their understanding of energy usage. Providing web-based tools for energy analysis would be a necessary component. Customers could view their daily energy usage, peak demand, load factor and weekend versus weekday usages to better manage their electric loads.

Fixed Metering Network:

A number of benefits of AMI may be achieved through the implementation of a fixed metering network in conjunction with CWL's existing Automatic Meter Read (AMR) meters and a Meter Data Management system (MDM). Physical meter reads and truck-driven AMR could be eliminated from operations and interval metering data collection on select customers could be achieved.

Staff Comments:

- Staff recommends creating a pilot program for residential customers which would allow the customer to expand their understanding of energy usage. Providing web-based tools for energy analysis would be a necessary component. Customers could view their daily energy usage, peak demand, load factor and weekend versus weekday usages to better manage their electric loads. Programs could include remote disconnect / reconnect and pay-as-you-go as well as opportunities for electric distribution system efficiency enhancement.

Back Office and IT:

Back office and IT upgrades and integrations are required to support many of these technologies and represent a significant portion of the costs. Since CWL has a relatively small customer base, economies of scale may be hard to achieve on expensive infrastructure and back office investments. Cost and complexity for these upgrades and integrations are equivalent regardless of number of customers and therefore may cost more on a per customer basis for a moderately sized utility like CWL.

Staff Comments:

- See Staff Recommendations in Burns and McDonnell Recommendations section on this topic below.

Existing DR Programs:

Based on CWL's wholesale energy cost, load modifying, Demand Response (DR) and peak shaving programs such as direct load control thermostats and dynamic rates may not provide sufficient peak generation or wholesale savings to cover their costs and potential loss of overall revenue due to expected collateral energy conservation that results from such programs.

Although these programs result in consumer conservation that reduces CWL financial performance, the conservation results in significant benefits to CWL customers.

Staff Comments:

- Staff recommends maintaining the functionality of the existing programs. CWL may need to review the program incentives and modify based on wholesale energy cost. CWL would need to phase this in with proper notice to customers, due to aligning of fiscal years for the various participants. CWL needs to be mindful of the Energy Service Companies (ESCOs) in CWL's territory providing programs and services. Some ESCOs have fully developed DR programs functioning in other Independent Operator Service territories. It is also recommended that CWL keep a watch on new developments within regulatory bodies with regard to DR initiatives. CWL may want to consider an ordinance to further protect the incurred investment made by CWL in the development of these programs and customer rapport already garnered from use by a third party aggregator.

Burns and McDonnell Conclusions

In the near-term (the next 12 months), BMcD does not believe that CWL should commit to any large scale investments in comprehensive smart grid upgrades and operational transformations. The return on investment direct to CWL cannot confidently be achieved as the technologies are relatively immature leading to some uncertain costs to implement, especially at moderately sized utilities. Additionally, full monetization of the potential benefits will require significant organizational, cultural, and behavior change on behalf of CWL personnel, stakeholders, and customers.

Although these investments currently represent significant financial risk, BMcD recognizes that the cost and benefit values associated with them will most-likely change quickly over the next three to ten years and should continue to be evaluated on a regular basis.

Staff Comments:

- At the time BMcD completed their report, CWL had begun several projects related to, but not necessarily for, smart grid including a new control center, new Energy Management System (EMS), Geospatial Information Systems (GIS) and new customer billing system.
- CWL believes BMcD's reference to large scale investment is related to full system change out in AMI metering. Many of the recommendations below can be achieved through a less expensive, phased approach.

Burns and McDonnell Recommendations

Customer Education:

CWL should begin placing greater emphasis on educating customers and personnel about the ongoing challenges and emerging opportunities in the industry. The future of the electric industry and customer interests are expected to evolve to a more complex environment that will require robust data-centric infrastructure. CWL should begin to gauge customer interests in adopting available technologies such as having access to interval usage data (through a web portal), advanced energy management technologies, and dynamic and non-standard rate options that incent behavior change, offer savings potential on electricity bills, and also benefit utility cost of service.

Staff Recommendations:

- In the 2014 annual customer phone survey, Columbia Water & Light collected opinions on different aspects of a smart grid from 751 customers. The margin of error for the survey was ±4.87% for residential and ±4.74% for commercial customers. The customers were asked to rate each on a scale of one to five where one is not useful and five is very useful.

  SURVEY QUESTIONS: If Columbia were to invest in new customer metering that would allow the utility to do the following, how useful would this new metering be to you? On the rating scale, five is very useful and one is not useful.

	5	4	3	2	1
More easily detect power outages?	47.6%	17.9%	15.8%	6.0%	12.8%
Provided comprehensive electric data?	41.5%	24.5%	14.1%	6.1%	13.8%
Remotely connect and disconnect customers?	40.4%	15.4%	17.6%	6.4%	20.2%

- Website information and a brochure will be developed about the abilities of the current metering system. Once the final scope of the smart grid project has been established, a complete education and outreach plan will be developed. Avenues for relaying the information could include, but are not limited to, public speaking outlets, community events, websites, social media, the City Source newsletter and videos for the City Channel and YouTube.
- CWL will continue to monitor public opinion and emerging technologies for other educational opportunities.
- CWL recently put on a department wide workshop to discuss smart grid technologies and how it can benefit the utility.

Back Office and IT:

CWL should begin examining efforts to increase foundational back office data quality and integration. In particular, operations and outage response performance could immediately benefit from integration of GIS data to existing Outage Management System (OMS) and Asset Management Systems in addition to preparing for future AMI, MDM, and Distributed Supervisory Control and Data Acquisition (DSCADA) systems.

Staff Recommendations:

- There are several projects underway in CWL and city wide that address this recommendation from BMcD. The upgrade of the City's utility billing system is underway. CWL is currently creating an electric model on the city's ArcGIS platform. CWL is also currently in the process of replacing its SCADA system with a more comprehensive EMS solution. Implementation of the EMS system and GIS electric model is estimated to be completed during FY2015.

Fixed Metering Network:

CWL should immediately evaluate the costs and feasibility of implementing a fixed metering network that is compatible with CWL's current electric meters and is capable of supporting more advanced smart meters as well. This specific upgrade could provide CWL with some immediate benefits, provide CWL personnel with valuable experience as industry technologies evolve, and enable an alternative, albeit slower, transition path toward full-scale AMI deployment. BMcD believes that CWL's current metering technology provider, Itron, is able to provide such a fixed network.

Staff Recommendations:

- Itron and their communications partner, Tantalus, provide a hybrid AMI-AMR metering network solution. An initial investigation into the design and costs of such a network has been undertaken by CWL. Such a network would make use of the CWL's current fiber infrastructure, a new WIMAX wireless communications system, and the meter to meter two-way communications network provided by Tantalus. Immediate benefits include:
    - Mobile meter reading nearly eliminated
    - OMS integration – quicker outage reporting
    - Basic meter data management reports
    - Voltage profiling of electric distribution circuits
    - Potential for customer interface

- Initial investment is estimated to be $2 million broken down by the following:

    - GE WIMAX Base Stations: $119,640
    - GE WIMAX Access Points: $256,050
    - Installation and Project Management: $100,000 (estimated)
    - Tantalus 2 way meter collector: $175,530
    - Itron Meter with Disconnect: $612,000
    - Tantalus Server and Software: $265,000
    - Tantalus Project Management: $100,000 (estimated)
    - CWL Installation Labor: $371,530 (estimated)

- Once the network is established, CWL has the option to proceed with other distribution management projects including but not limited to:

    - Volt/Var optimization
    - Expansion of remote disconnect
    - Remote switching from control center
    - Load management and demand response
    - Advanced Distribution Management expansion of EMS system

- CWL is searching for locations for the pilot program(s) that would be suitable for implementations of AMR/AMI technologies for both water and electric systems. Implementation is estimated to occur during FY2016.

Distribution Automation (DA):

CWL should consider further evaluation of various DA technologies. Significant operational savings may be realized by enabling remote operation of substation and field devices and reducing distribution losses on the electric distribution system. Enhanced operational awareness and flexibility could also improve reliability.

Staff Recommendations:

- Significant operational savings could be realized in faster outage response and automatic self-healing distribution networks which would require less staff response.

Cyber Security:

CWL should consider conducting a thorough cyber security threat and vulnerability evaluation and gap analysis relative to the guidelines of NISTIR 7628 - Guidelines for Smart Grid Cyber Security. Subsequently, CWL should consider developing a cyber-security strategy to address or mitigate known risks.

Staff Recommendations:

- As part of the EMS project a new infrastructure is being developed to address the requirements of NERC CIP version 5 and NISTIR 7628. Also, the recently completed CWL control center was designed to meet cybersecurity and other security requirements.

Additional Infrastructure:

Evaluation of future infrastructure investments at CWL should assess each investment's role in the development of a diverse and robust portfolio of distributed energy resources that could be aggregated into a fully integrated system.

BMcD believes many of the infrastructure upgrades associated with the smart grid industry movement bear significant value potential. However, it is not clear if this heavily regulated and monitored industry will be capable of quickly converting that potential into tangible stakeholder and customer value. At a minimum, operational transformations on this scale require robust executive commitment in order to be successful. It is also important to note that many of the sought-after benefits are dependent on customer engagement and behavior changes that must be incented, accommodated, and maintained adequately.

Staff Recommendations:

- As CWL installs new and maintains its existing infrastructure, staff and senior management have been and will continue to incorporate the necessary technologies to be compatible with a smart grid implementation.

Burns & McDonnell
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Report on the

SMART GRID BUSINESS CASE

Columbia Water & Light

Project No. 67800

June 2013

Smart Grid Business Case

prepared for

Columbia Water & Light
Columbia, Missouri

June 2013

Project No. 67800

prepared by

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

Revision 6/10/13

Burns & McDonnell
SINCE 1898

June 10, 2013

Mr. Ryan Williams
Assistant Director
City of Columbia, Missouri
Water & Light Department
701 East Broadway
P.O. Box 6015
Columbia, Missouri 65205-6015

Smart Grid Business Case Study
Project Number 67800

Dear Mr. Williams:

Burns & McDonnell is pleased to submit this Smart Grid Business Case Study, prepared for Columbia Water & Light (CWL). This report was prepared and submitted pursuant to the consulting services agreement between CWL and Burns & McDonnell, dated May 4, 2012.

The purpose of this business case study is to help guide CWL in determining which Smart Grid components and implementation strategy are best suited for CWL. For the project, Burns & McDonnell focused on the potential integration of Smart Grid technologies into the existing CWL electric system.

We appreciate the opportunity to complete this assignment for CWL. We are grateful for the cooperation and assistance we received from the CWL staff throughout this project. If you have any questions regarding this report or the analysis we completed, please feel free to contact Ted Kelly at (816) 322-3208 or Lucas McIntosh at (816) 823-6214.

Sincerely,
BURNS & McDONNELL

Ted J. Kelly
Principal & Senior Project Manager
Business & Technology Services

Lucas McIntosh
Project Manager
Business & Technology Services

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LIST OF ABBREVIATIONS AND ACRONYMS

AMI	Advanced Meter Infrastructure
AMR	Automated Meter Reading
ARRA	American Recovery and Reinvestment Act
BMcD	Burns & McDonnell Engineering Company, Inc.
CIS	Customer Information System
CPP	Critical Peak Pricing
CPR	Critical Peak Rebate
CVR	Conservation Voltage Reduction
CWL	Columbia Water & Light
DA	Distribution Automation
DER	Distributed Energy Resource
DLC	Direct Load Control
DMS	Distribution Management System (often coupled with OMS)
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSM	Demand Side Management
DVC	Dynamic Voltage Conservation
DVR	Dynamic Voltage Regulation
EMS	Energy Management System
FACTS	Flexible AC Transmission System
FCI	Fault Circuit Indicator
FLISR	Fault Location Isolation and Service Restoration
GIS	Geographic Information System
HAN	Home Area Network
IHD	In-Home Display
IVVC	Integrated Volt/Var Control
LTC	Load Tap Changer
MDM	Meter Data Management
MWM	Mobile Workforce Management
OMS	Outage Management System
PCT	Programmable Communicating Thermostat
PLC	Programmable Logic Controller
PMU	Phasor Measurement Unit
PTR	Peak Time Rebate
PV	Photo Voltaic (Solar)
ROI	Return on Investment
SCADA	Supervisory Control and Data Acquisition
Study	Smart Grid Business Case
TOU	Time of Use
VPP	Variable Peak Pricing
WAN	Wide Area Network

* * * * *

STATEMENT OF LIMITATIONS

In preparation of this Study, Burns & McDonnell (BMcD) has relied upon information provided by Columbia Water & Light (CWL). While BMcD has no reason to believe that the information provided, and upon which BMcD has relied, is inaccurate or incomplete in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness.

Estimates and projections prepared by BMcD relating to performance and costs are based on BMcD's experience, qualifications, and judgment as a professional consultant. Since BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, contractors' procedures and methods, unavoidable delays, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding, and market conditions or other factors affecting such estimates or projections, BMcD does not guarantee the accuracy of its estimates or predictions.

STATEMENT OF CONFIDENTIALITY

This report may have been prepared under, and only be available to parties that have executed, a Confidentiality Agreement with CWL. Any party to whom the contents are revealed or may come into possession of this document is required to request of CWL if such Confidentiality Agreement exists. Any entity in possession of or that reads or otherwise utilizes information herein, is assumed to have executed or otherwise be responsible and obligated to comply with the contents of such Confidentiality Agreement. Any entity in possession of this document shall hold and protect its contents, information, forecasts, and opinions contained herein in confidence and not share with others without prior written authorization from CWL.

REVISION HISTORY

Revision	Issue Date	Author	Reviewer	Notes
0	07-May-2013	McIntosh/Bartak	Kelly	Original release.
1	10-June-2013	McIntosh/Kelly	Blackwell	

* * * * *

1.0 EXECUTIVE SUMMARY

1.1 SMART GRID OVERVIEW

The utility industry in the United States is in the midst of a transformative process of integrating modern electronic sensing and communication technologies into the traditional utility infrastructure to deliver more efficient and responsive services to customers. The technologies and processes to implement these changes are commonly referred to as "smart grid."

The smart grid has different definitions and implications depending on one's perspective.

- From a **Regulatory Perspective,** the smart grid mainly fosters grid stability and grid reliability on a national scale.
- From a **Utility Perspective,** the smart grid will provide enhanced load forecasting, improved load control, and more efficient and automated operations.
- From a **Customer Perspective,** the smart grid will offer improved service reliability, potentially cheaper prices for electricity, detailed information about their energy usage, and enable greater choice and control over their energy usage.

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

Columbia Water & Light (CWL) is aware of significant investment and adoption of smart grid technologies across the industry and is performing this assessment in order to evaluate the feasibility and value of these types of investments and technologies on the CWL system.

1.2 CWL ASSESSMENT

Implementing smart grid solutions has the potential to touch almost every aspect of the CWL organization, including Customers, Metering, Electric distribution, Back office systems and architecture, Network communications, and Security and compliance. The following subsections describe CWL operations and programs in these areas relative to typical smart grid considerations and the assessment is summarized in Figure 1.1.

1.2.1 Customers

A major portion of smart grid equipment and technologies are intended to facilitate customer choice and control over their energy usage. This includes offering or at least supporting the implementation of tools that enable customers to manage their energy consumption coupled with incentives that encourage responsible energy management. A successful smart grid implementation that has a focus on customer programs will rely heavily on customer participation to achieve increased grid efficiency, utilization, and customer satisfaction.

CWL currently offers many programs for customer engagement and awareness, including a bill review and payment web portal, energy audits, efficiency rebates and a DLC program. CWL's website offers tips on conserving electricity and water, as well as information on xeriscaping and selecting the proper shade trees. CWL does not currently offer any prepayment or dynamic rate programs to residential customers.

1.2.2 Metering

To improve operational efficiency, obtain interval usage data, two-way communications with customers, and advanced distribution system awareness; many utilities are implementing advanced metering networks, often referred to as Advanced Metering Infrastructure (AMI). AMI includes sophisticated solid state meters coupled with a robust wireless network that allows utilities to capture enhanced data from meters quickly and remotely. The AMI metering infrastructure enables advanced functionality to utilities and facilitates increased communications and information delivery to their customers.

CWL currently utilizes a mixture of older electromechanical meters and newer solid state meters. CWL employs seven meter readers who read all CWL meters once a month through either visual readings or via close range capture of ERT messages with handheld units. CWL does not have a system-wide fixed metering network capable of capturing reads or notifications from electric or water meters, nor are any of their meters equipped with remotely controlled connect/disconnect switches.

1.2.3 Electric Distribution

Another integral component to a smart grid system is an advanced electricity distribution system that is remotely controllable and flexible to changing load conditions. This is accomplished primarily through increased monitoring, remote control, and automation of the distribution system assets.

CWL operates robust electric and water distribution systems that reliably serve the City of Columbia and surrounding areas. CWL has implemented a traditional SCADA system with remote monitoring and control of critical assets and some intelligent devices on select feeders outside of the substation with local intelligence or dedicated one-way remote control. CWL could consider deploying a distribution SCADA network with remote operable field devices.

1.2.4 Back Office

Smart grid technology deployments such as interval metering, distribution asset monitoring, and automation will produce significantly more data than utilities currently collect, manage, store and use. Maximum utilization of these data requires an upgraded back office infrastructure that enables accessibility to data and tools to convert the data to actionable information.

CWL currently shares numerous back office resources and IT personnel with the City of Columbia, including issuing electric and water utility bills to customers through a common Customer Information System (CIS). At this time, CWL and the City of Columbia are in the process of implementing and evaluating numerous upgrades to their back office systems and infrastructure that will support current and future smart grid related functionalities.

1.2.5 Communication Systems

Remote meter reading, DSCADA, distribution automation, remote monitoring of critical infrastructure, and DR/DSM are examples of smart grid features that require a robust, high bandwidth, two-way communication infrastructure that connects various endpoints across the service territory. This can be accomplished through the development of a proprietary and utility-owned Wide Area Network (WAN) and/or by securing/leasing bandwidth on existing third party communications systems such as cellular or radio networks.

CWL owns and operates an extensive fiber network throughout its service territory that connects all substations to the control center (see Appendix B). CWL primarily uses this fiber network to transmit SCADA traffic. This fiber network should provide an adequate backbone to support the addition of new utility networks such as a wireless fixed metering network, wireless DSCADA network, or other distribution field networks to communicate with CWL field devices. CWL has not yet implemented a fixed metering network, DSCADA, or distribution field network.

1.2.6 Security and Compliance

Implementation of data intensive technologies along with additional networks creates new sensitive data and vulnerabilities. This data may consist of critical utility operational data and sensitive customer usage information. Both types, if left unprotected, can result in reliability and privacy risks if exposed.

CWL does incorporate physical security measures at generating facilities, substations, and facilities but has not developed a comprehensive and robust cyber or physical security strategy. CWL has not yet audited their systems and networks to evaluate compliance with NISTIR 7628 and are not required to do so. CWL is considering such an evaluation and developing a maintenance program aimed at achieving and sustaining compliance.

Figure 1.1: CWL Smart Grid Assessment Matrix

	Smart Grid Functionalities	CWL has Implemented	CWL is Considering	CWL should Consider
Customers	Customer Web Portal with Usage and Bill Info	√		
	Time Varying Rates - Load Factor	√	√	
	Time Varying Rates - Demand Response		√	
	Direct Load Control Programs	√		
	Conservation Education & Tips	√		
	Interval Data Available to Operations/Engineering		√	
Metering	Remote Connect/Disconnect			√
	Remote On-Demand Reads/Status			√
	Automated Outage Notification			√
	System & Subsystem Load Data	√		
	Fixed Network			√
	Interval Load Data on Each Customer			√
Electric Distribution	Volt/Var Optimization (VVO)		√	
	Dynamic Voltage Conservation (DVC)			√
	Conservation Voltage Reduction (CVR)			
	FLISR (Automated Sectionalizing)			√
	Remote Asset Monitoring & Control			√
	Condition-Based Maintenance		√	
	Transformer Monitoring/Rating			√
	Coordinated Protection Schemes			√
	Phasor Measurement Units			√
	Dynamic Cable Ratings			√
Back Office	Systems/Data Integration			√
	Operational Data Logging & Trending			√
	Advanced Data Analytics			√
	Customer Segmentation & Target Marketing			√
	Compliance Tracking & Verification			√
Comms	Fiber Backhaul Network	√		
	Transmission/Substation SCADA	√		
	Distribution SCADA			√
	Fixed Metering Network			√
	Distribution Field Network			√
Security	Robust Physical Security Strategy			√
	Robust Cyber Security Strategy			√
	Full NERC CIP Compliance (NISTIR)		√	
	NERC CIP Compliance Maintenance Program		√	

1.3 RETURN ON INVESTMENT SUMMARY

The primary economic drivers for CWL to consider when evaluating investments in smart grid infrastructure upgrades include increasing operational efficiency, reducing operating costs, and reducing wholesale power purchase costs.

Cash flow analysis was performed on three alternative smart grid investment scenarios for CWL. The analysis estimates initial investment costs, ongoing annual costs and all monetary benefits over a 15 year period. The three scenarios considered in this business case analysis include:

1. **Scenario #1: CWL-owned Comprehensive Solution**
   This approach would involve full-scale replacement of all electric and water meters with AMI and include the deployment of distribution system upgrades quickly in order to begin benefit realization as soon as possible.
2. **Scenario #2: Vendor-hosted Comprehensive Solution**
   The hosted solution provides equivalent functionality to the CWL-owned comprehensive solution; however, a vendor provides a significant portion of the technologies and equipment to CWL as a service (similar to a leasing agreement) rather than a traditional capital expenditure.
3. **Scenario #3: Enhanced AMR Approach**
   This approach would leverage some of CWL's existing assets. A metering network would be deployed compatible with existing meters and new smart meters to enable a strategic transition. Distribution upgrades would be equivalent to the previous scenarios. This approach will limit capital investment and enable full life utilization of some current assets.

To account for uncertainty in estimating costs and tangible benefit values, BMcD established *Nominal*, *Aggressive*, and *Conservative* case assumptions for each input into the analysis. Additionally, since energy conservation is a potential byproduct of customer programs designed to manage system demand and associated wholesale power purchases, BMcD analyzed each scenario and assumption type both with and without those programs and associated conservation. Table 1.1 below compares the net 15 year cost/benefit calculation for each scenario and assumption type combination. Based on this analysis, Scenario #3 has a positive return on investment under all assumptions both with and without conservation. Scenario #1 has a positive return on investment under the *Aggressive* assumptions.

Table 1.1: Summary of ROI Results – CWL Direct Net Cost/Benefit

	Assumption Type	Scenario #1	Scenario #2	Scenario #3
With DSM Programs	Aggressive	$1,900,000	$(63,900,000)	$19,200,000
	Nominal	$(14,900,000)	$(77,300,000)	$9,700,000
	Conservative	$(31,400,000)	$(89,200,000)	$1,700,000
Without DSM Programs*	Aggressive	$3,700,000	$(62,300,000)	$20,200,000
	Nominal	$(10,700,000)	$(73,100,000)	$12,100,000
	Conservative	$(25,600,000)	$(83,400,000)	$5,000,000

** "Without DSM Programs" cases exclude revenue losses associated with customer conservation from DSM programs*

When customer benefits are included in the cost/benefit calculation, net benefits increase due to the savings opportunities and improved service they receive. However, in general, Scenario #3 still results in the best overall return on investment. It is important to note the large difference in calculated net benefits between the Aggressive and Conservative assumptions. This demonstrates the impact uncertainty in both cost and benefit values have on the viability of the investments. Table 1.2 summarizes the net 15 year cost/benefit calculations for each scenario and assumption combination including customer benefits.

Table 1.2: Summary of ROI Results – CWL and Customers Net Cost/Benefit

	Assumption Type	Scenario #1	Scenario #2	Scenario #3
With DSM Programs	Aggressive	$18,700,000	$(47,100,000)	$34,700,000
	Nominal	$500,000	$(61,800,000)	$23,800,000
	Conservative	$(17,700,000)	$(75,500,000)	$14,000,000
Without DSM Programs*	Aggressive	$7,800,000	$(58,200,000)	$24,300,000
	Nominal	$(7,100,000)	$(69,600,000)	$15,700,000
	Conservative	$(22,700,000)	$(80,500,000)	$7,900,000

** "Without DSM Programs" cases exclude revenue losses associated with customer conservation from DSM programs*

In alignment with Net Cost/Benefit calculation results, Scenario #3 is expected to provide the shortest payback on investment to CWL direct, ranging from approximately a six year payback without customer conservation (See Figure 1.3) to approximately a nine year payback with customer conservation (See Figure 1.2). When customer benefits are included, payback both with and without customer conservation is expected to be approximately six years (See Figure 1.4 and Figure 1.5).

Figure 1.2: ROI Results of Direct Benefits to CWL with Conservation

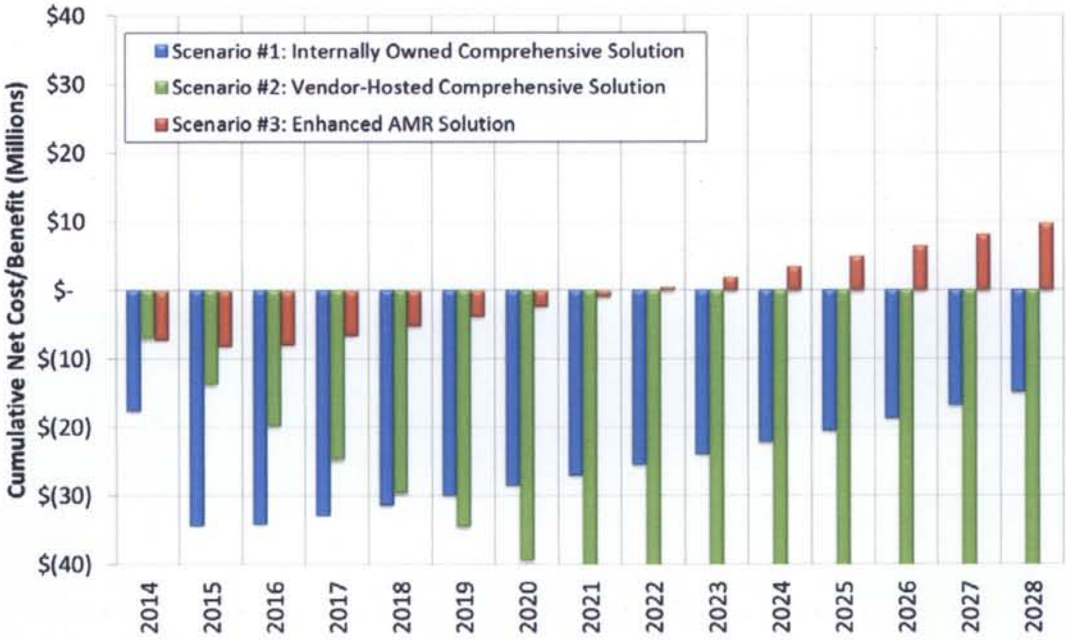


Figure 1.3: ROI Results of Direct Benefits to CWL without Conservation

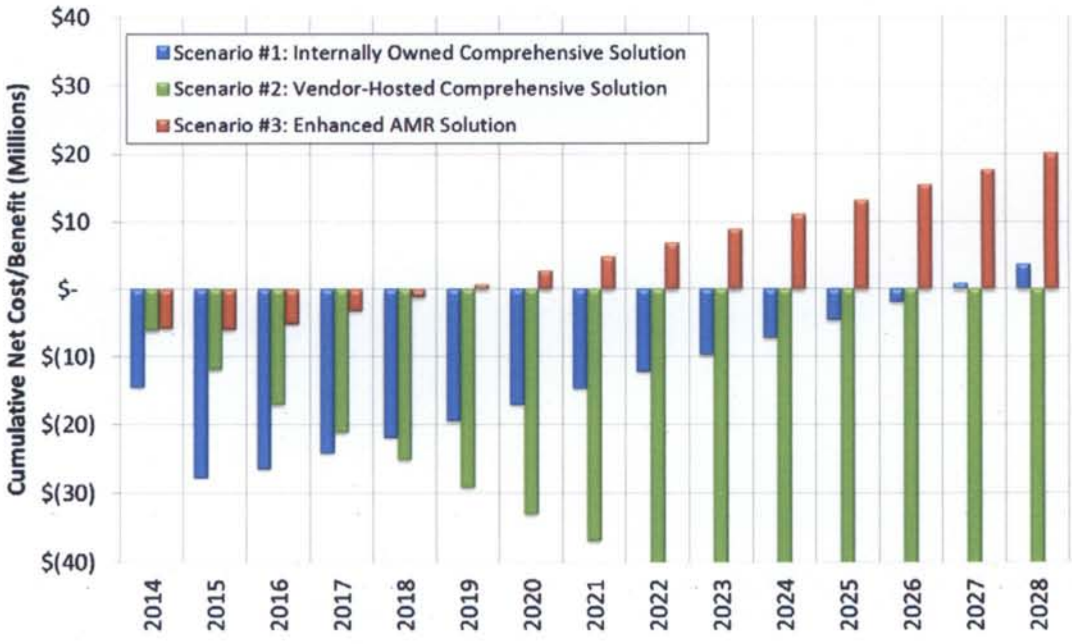


Figure 1.4: ROI Results of Benefits to CWL and Customers with Conservation

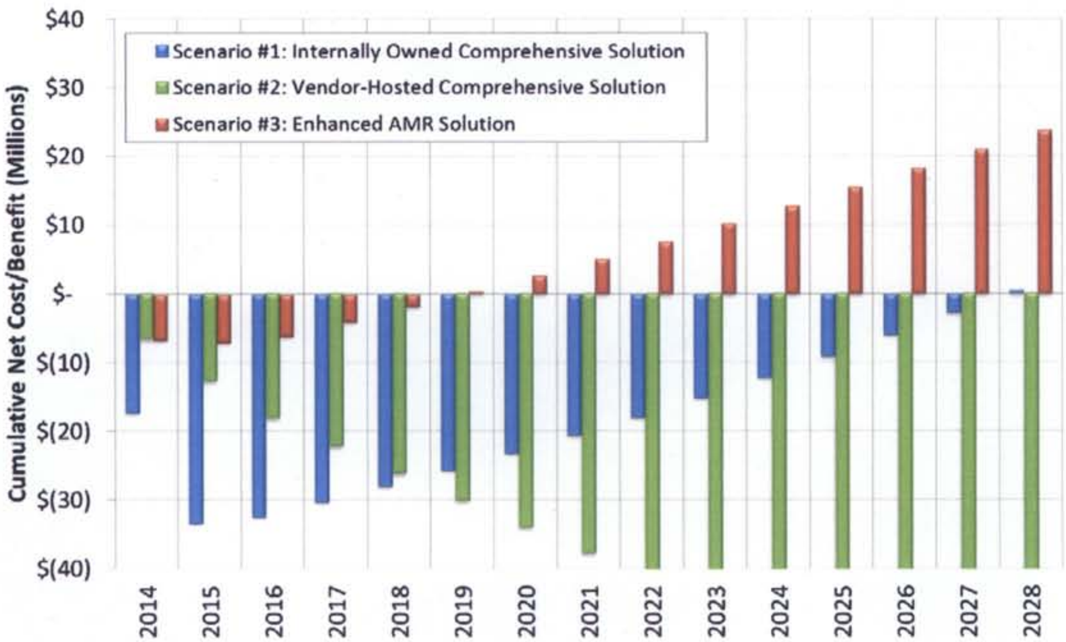
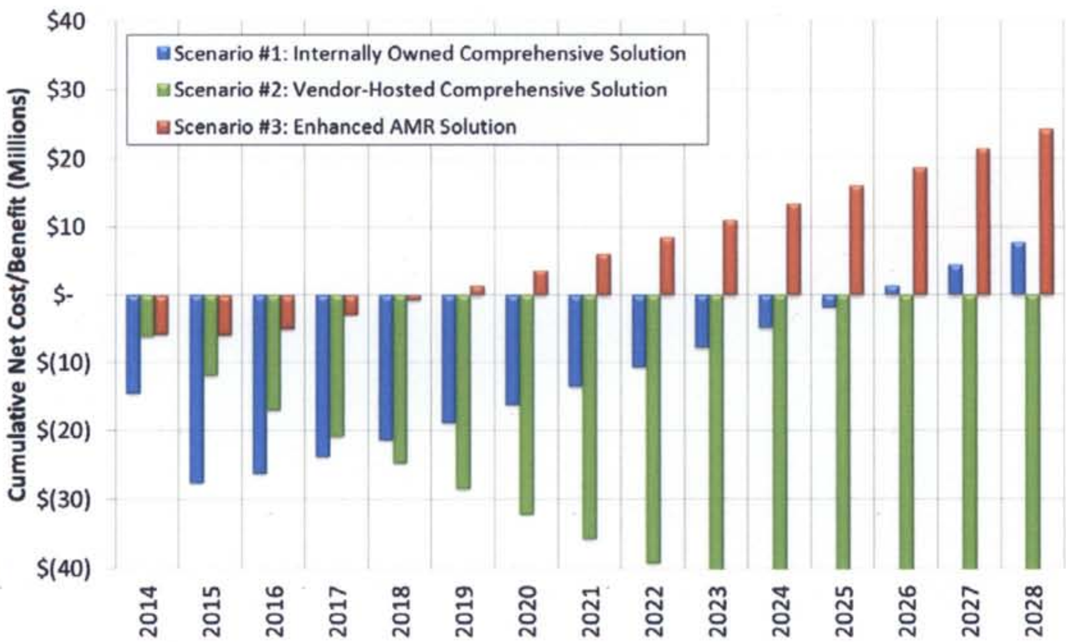


Figure 1.5: ROI Results of Benefits to CWL and Customers without Conservation



In all assumption cases, Scenario #2 Vendor-hosted Solution is expected to result in a negative return on investment. Based on the information available, including estimated costs from vendors, BMcD calculates that the costs outpace the benefits on a recurring annual basis. Despite significant recurring annual costs associated with the hosted-solution, there are some notable benefits that BMcD feels should be thoroughly considered. Those benefits include:

- Quick deployment and conversion to new systems as the hosted environments are already established and don't require extensive customization, installation or testing
- Reduced need to acquire personnel with skill sets needed to operate and maintain new systems
- Single point of contact and payee to address numerous systems
- Experienced vendor support on redesign of business processes to align with new systems

1.4 SMART GRID INVESTMENT RECOMMENDATIONS

Although many utilities across the country are investing heavily in metering and distribution system upgrades to implement data-centric architectures and increase automation, many appear to be struggling to fully achieve expected efficiencies and monetize the sought-after benefits from these investments. BMcD believes many of the challenges emerging with monetizing these benefits are primarily due to inaccurate cost and benefit expectations and a lack of utility personnel readiness to adapt and embrace the necessary operational transformations associated with these large infrastructure upgrades and associated process changes.

This business case analysis has assessed CWL's current infrastructure and technology utilization and has identified a number of investments CWL could consider to improve operational performance and efficiency. These upgrades could also enable CWL to more effectively manage generation and wholesale power costs to meet customer usage and demand.

As CWL continues to provide reliable service to its customers and plan for future investments in their assets and operations, **BMcD recommends the following**:

- CWL should immediately evaluate the costs and feasibility of implementing a fixed metering network that is compatible with CWL's current electric meters and is capable of supporting more advanced smart meters as well. This specific upgrade could provide CWL with immediate benefits and enable an alternative, albeit slower, transition path toward full-scale AMI deployment. BMcD believes that CWL' current metering technology provider, Itron, is able to provide such a fixed network.

- CWL should begin placing greater emphasis on educating customers and personnel about the ongoing challenges and emerging opportunities in the industry. The future of the electric industry and customer interests are expected to evolve to a more complex environment that will require cooperation between utilities and customers and a robust data-centric infrastructure. As such, CWL should begin to gauge customer interests in information, technologies and programs that incent behavior change, offer savings potential, and reduce utility cost of service.
- CWL should begin examining efforts to increase foundational back office data quality and integration. In particular, operations and outage response performance could immediately benefit from integration of GIS data to existing OMS and Asset Management Systems in addition to preparing for future AMI, MDM, and DSCADA systems.
- CWL should consider further evaluation of various DA technologies. Significant operational savings may be realized by enabling remote operation of substation and field devices and reducing distribution losses on both the electric and water systems. Enhanced operational awareness and flexibility could also improve reliability.
- CWL should consider conducting a thorough cyber security threat and vulnerability evaluation and gap analysis relative to the guidelines of NISTIR 7628 - Guidelines for Smart Grid Cyber Security. Subsequently, CWL should consider developing a robust cyber security strategy.
- Evaluation of future infrastructure investments at CWL should assess each investment's role in the development of a diverse and robust portfolio of distributed energy resources that could be aggregated into a fully integrated system (see Section 4.7).

BMcD believes many of the infrastructure upgrades associated with the smart grid industry movement bear significant value potential. However, it is not clear if this heavily regulated and monitored industry will be capable of quickly converting that potential into tangible stakeholder and customer value. At a minimum, operational transformations on this scale require robust executive commitment in order to be successful. It is also important to note that many of the sought-after benefits are dependent on customer engagement and behavior changes that must be incented, accommodated, and maintained adequately.

Recent and current smart grid deployments around the country have been driven by government funding and regulatory initiatives. However, the risks of being an early adopter may outweigh the direct monetary benefits for CWL. Costs of implementing some smart grid technologies are expected to decline over the next few years as technology matures. Thus moving at a slower pace in implementing some of the technologies could improve the cost/benefit assessment for CWL.

* * * * *

2.0 SMART GRID OVERVIEW

2.1 WHAT IS THE SMART GRID?

The smart grid has different definitions and implications depending on one's perspective.

- From a **Regulatory Perspective**, the smart grid mainly fosters grid stability and grid reliability on a national scale. However, federal and state regulations also advocate customer rights to their own detailed usage information.
- From a **Utility Perspective**, the smart grid will provide enhanced load forecasting, improved load control, and more efficient and automated operations. It will improve the utility's ability to manage load, distribution, and generation while providing improved power quality and service to its customers.
- From a **Customer Perspective**, the smart grid will offer improved service reliability, potentially cheaper prices for electricity, detailed information about their energy usage, and enable greater choice and control over their energy usage. This information and control may be utilized to reduce carbon footprint and reduce energy costs.

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

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

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

- Inertia of moving to a new way of operating and billing (both internal and external)
- Fear of technical obsolescence
- Skepticism regarding benefits as compared to cost
- Customer resistance to change

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

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

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

2.2 NATIONAL SMART GRID TRENDS

Currently there are diverse smart grid implementations occurring across the industry. Some utilities are taking an all-inclusive approach while others are selectively incorporating elements of the smart grid. Figure 2.1 presents a map of smart grid projects funded that received funding from the American Recovery and Reinvestment Act of 2009. While this activity alone is substantial, the map does not include projects that were funded by utilities prior to the availability of stimulus grants. Table 2.1 and Appendix A list the Midwest utilities that received grant money and include the amount each utility received. Appendix A also includes a description of the project each utility is undertaking.

Figure 2.1: Smart Grid Projects Funded by ARRA

Courtesy of DOE: 2010 Smart Grid System Report Report to Congress February 2012

Table 2.1: Smart Grid Projects Funded by ARRA in the Midwest

Project	Grant Award Amount	Total Project Value
Ameren Services Company	\$5,679,895	\$9,200,000
City of Fulton, MO	\$1,527,641	\$3,174,962
City of Naperville, IL	\$10,994,110	\$21,988,220
Eastern Nebraska Public Power District Consortium	\$1,874,994	\$3,749,988
Iowa Association of Municipal Utilities	\$5,000,000	\$12,531,203
Kansas City Power & Light	\$23,940,112	\$49,830,280
Midwest Energy	\$712,257	\$1,424,514
Midwest Independent Transmission System Operator	\$17,271,728	\$34,543,476
Oklahoma Gas & Electric Company	\$130,000,000	\$357,376,037
Stanton County (NE) Public Power District	\$397.000	\$794,000
The Boeing Company	\$8,561,396	\$17,172,844
Westar Energy	\$19,041,565	39,290,749
Woodruff Electric Cooperative	\$2,357,520	\$5,016,000
	\$226,961,615	**\$556,092,273**

Courtesy of www.smartgrid.gov

Pike Research has identified *Ten Smart Grid Trends to Watch in 2012 and Beyond*, published in the May 2012 issue of POWER Magazine. These trends provide a snapshot of the overall smart grid industry and highlight some issues to watch.

Ten Smart Grid Trends to Watch in 2012 and Beyond

1. **Smart Meters Will Shift from Deployment to Applications**. Federal stimulus funds helped push the deployment of smart meters. As that initiative concludes, the focus will shift from deployment to figuring out what to do with all the data. Expectations will turn to delivering results.
2. **Dynamic Pricing Debates Will Escalate**. Changing from average rates to dynamic pricing has opponents on all sides of the political spectrum. Subsidies will become more obvious, which will likely drive the need for disadvantaged assistance programs.
3. **"Architecture" Will Be the New Buzzword**. Grid management becomes more powerful as key components of the electric system are integrated, which is easier said than done. Recent industry trends point to a more common architectural vision which should help.
4. **Cyber Security Failure Risks Will Near Inevitability**. Lack of enforceable standards for smart grid cyber protection creates uncertainty, which causes utilities to be slow to invest and vendors disjointed in the development of solutions.
5. **Consumer Backlash Will Not Go Away**. Opponents have been successful in prompting utilities to allow opt-out programs. Engaging the public is critical in creating a common understanding of smart grid initiatives and addressing concerns.
6. **DA and AMI Will Intersect**. Distribution Automation (DA) and Advanced Metering Infrastructure (AMI) lines are blurring as the need to use meaningful data across the applications becomes more important.
7. **Microgrids Will Move from Curiosity to a Reality**. Industry standards and FERC orders are changing the way demand response works. Microgrids are expected to provide a strong demand response resource.
8. **The Freeze on HANs Will Thaw – Just a Little**. Home area networks (HAN) interfaces are still being tested by several utilities. It is unclear whether consumers would rather get their demand information from them, or from other sources such as smart phones or laptops.
9. **Asia Pacific Smart Grid Adoption Will Accelerate Even More**. Investment in China, Japan, and other countries in Southeast Asia is expected to grow.
10. **Stimulus Investments Will Bear Mixed Fruit**. The ARRA program funneled $4.5 billion into smart grid initiatives, with incentives to emphasize deployment. The rush to deploy resulted in a

one-size-fits-all approach being used more often than perhaps it should, which may mitigate some of the benefits that can be achieved.

Beyond these national trends and issues, much activity has occurred across the Midwest regarding smart grid initiatives.

2.3 MIDWEST SMART GRID ACTIVITIES

Several utilities within the Midwest region are overhauling their distribution infrastructure and piloting advanced Smart Grid initiatives for customers, such as time-of-use rates and demand response technologies.

2.3.1 City of Fulton, MO, *Smart Grid Project*

The City of Fulton, Missouri, (Fulton) Smart Grid Project involves the installation of over 5,700 smart meters to all residential, commercial, and electric meters within Fulton. By installing this AMI system, Fulton benefits from two-way communication and utility application that allows customers to view electric consumption at their convenience through the Web portal, as well as the implementation of a time-based rate program that allows customers to better manage electric usage and cost.

Fulton's AMI smart meters provide daily history of electricity usage and allow remote reading, remote power shut-offs, and remote control of in-home devices such as programmable communicating thermostats. Other features of the smart meter include outage notification and voltage monitoring capabilities. The potential of these features will be fully captured with the deployment of distribution voltage control devices.

A smaller portion of Fulton's customers utilize the advanced electricity service options such as programmable communicating thermostats and deployment of home area networks providing access to a Web-based information portal. These instruments allow better two-way communication between the customer and utility, giving greater reduction in cost and electric usage regarding their selected rate structure.

Fulton also offers time-based rate programs, as well as critical peak rebates for residential and small commercial customers receiving smart meters, in an effort to manage peak electricity demand and provide practical solutions for customer's electric cost reduction needs.

2.3.2 City of Naperville, IL, *Smart Grid Initiative*

The City of Naperville (Naperville) Smart Grid Initiative project involves a city-wide deployment of an AMI system and an expansion of distribution automation capabilities, which includes circuit switches, smart relays, and remote fault indicators. Along with the utility's new installments, Naperville's customers are allowed to purchase devices that assist in managing electricity use and costs, including in-home displays, programmable communicating thermostats, and direct load control devices for participation in load management programs. The overall goals of this project are to allow customers to view energy usage by way of in-home displays or through a Web portal, as well as give Naperville the ability to manage, measure, and verify targeted demand reductions during peak periods.

Naperville's smart grid system links all substations and utility operations centers with meters, distribution automation devices, and an existing fiber backhaul network by utilizing a new digital mesh radio network. This upgraded infrastructure allows for ease of communication between customer information, energy delivery system operations, and system reliability information. Over 57,000 new smart meters have been deployed throughout Naperville, allowing for automated meter reading, improved meter accuracy, enhanced outage detection, power quality monitoring, and improved meter tampering detection. A new meter data management system and load control management system provide expanded capabilities to analyze, interpret, and query meter readings and power usage information, thereby improving billing and electricity management efforts and load forecasting abilities. Along with smart meters, more advanced electricity service options have been installed into select Naperville residential and commercial buildings. These advanced options include programmable communicating thermostats, in-home displays, or other home energy devices, giving the occupant load control management capabilities. In addition to customer load control, Naperville has implemented advanced electricity service options allowing direct load control on specific appliances and equipment. All of these enhancements, paired with time-based rate programs, provide the customer the ability and incentive to shift their use and reduce peak demand.

Naperville's Smart Grid Initiative includes a time-based rate program that includes both time-of-use rates as well as critical peak pricing. Time-based programs incentivize customers to shift usage, which helps reduce the peak demand of the utility and allows for a reduction in greenhouse gas emissions. Commercial customers have the option of different demand rates for peak and off-peak periods. Time-based rate programs will be rolled out gradually in conjunction with traditional flat rates. Other future rates may include an electric vehicle charging rate and a renewable energy sources rate.

2.3.3 Iowa Association of Municipal Utilities, *Smart Grid Thermostat Project*

The Iowa Association of Municipal Utilities (IAMU) Smart Grid Thermostat project involves the deployment of advanced metering and customer systems for five participating municipal utilities. This project allows for reduced electricity cost for customers, reduced greenhouse gas emissions, deferred investment in generation, and distribution capacity expansion. IAMU's AMI deployment includes over

5,400 smart meters to residential, commercial, and industrial customers. In addition to smart meter deployment, IAMU has installed over 13,800 programmable communicating thermostats and direct load control devices. The new infrastructure enables customers to view and control their energy consumption at their convenience through a Web portal, as well as allow participating utilities to manage, measure, and verify targeted demand reductions during peak periods.

2.3.4 Oklahoma Gas & Electric Company, *Positive Energy® Smart Grid Integration Program*

The Oklahoma Gas and Electric Company (OG&E) program involves system-wide deployment of a fully integrated advanced metering system, distribution of in-home devices to almost 6,000 customers, and installation of advanced distribution automation systems. Implementation of the program allows for reductions in peak load, overall demand, operating and maintenance costs, and greenhouse gas emissions, while increasing distribution efficiency, reliability, and power quality.

Upgraded infrastructure allows OG&E to maintain, manage, and measure targeted demand reductions during peak periods. The new system has the capability to utilize gathered meter information for billing and implement new customer pricing programs and service offerings. In addition to utility benefits, customers can view their electricity consumption data at any time through a personalized Web portal. The new system allows for a more dynamic distribution management system, automated switching, and integrated Volt/Var control (IVVC) that reduces line losses and operational costs, and improves service reliability.

These system enhancements are achieved by way of a new secure wireless network system that provides the backbone for the energy management programs. The new communication infrastructure allows OG&E's 790,000 deployed smart meters to interact with smart appliances and home area networks. This system provides automated meter reading, improved meter accuracy, enhanced outage response and notification, and improved theft-of-service detection. More detailed and timely data on peak electricity usage improves load forecasting and capital investment planning. Advanced electricity service options offered through the program include Web portal access, in-home display devices, energy management systems, and programmable communicating thermostats. These devices are intended to help customers make decisions to reduce their peak electricity load and overall energy usage on a real-time basis.

2.3.5 Kansas City Power & Light, *Green Impact Zone Smart Grid Demonstration*

Kansas City Power & Light (KCP&L) is demonstrating an end-to-end SmartGrid solution – built around a major urban substation with a local distributed control system based on IEC 61850 protocols and control processors – that includes advanced generation, distribution, and customer technologies.

Co-located renewable energy sources, such as solar and other parallel generation, will be placed in the demonstration area and will feed into the energy grid. The demonstration area consists of eleven circuits served by one substation across two square miles with 14,000 commercial and residential customers. Part of the demonstration area contains the Green Impact Zone, 150 inner-city blocks that suffers from high levels of unemployment, poverty, and crime. Efforts in the Green Impact Zone will focus on training and educating residents to implement weatherization and energy efficiency programs to reduce utility bills, conserve energy, and create jobs.

KCP&L's SmartGrid program will upgrade local infrastructure and provide area businesses and residents with enhanced reliability and efficiency through real-time information about electricity supply and demand. It will enable customers to manage their electricity use and save money through pilot demand response programs, devices, and rates.

Technology deployments include pilot AMI, distribution automation, utility-owned PV, DSCADA, DMS, OMS, and a Distributed Energy Resource (DER) management system (similar to a virtual power plant concept). In addition to these grid technologies, the pilot includes some customer programs and devices such as TOU rates, PCTs, and IHDs.

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3.0 SMART GRID ASSESSMENT

3.1 SMART GRID ELEMENTS

Implementing smart grid solutions has the potential to touch almost every aspect of the CWL organization. This section of the report will consider the impact of smart grid from the context of:

- Customers
- Metering
- Electric distribution
- Back office systems and architecture
- Communications
- Security and compliance

3.2 CUSTOMERS

3.2.1 Industry Perspective

A major portion of smart grid equipment and technologies are intended to facilitate customer choice and control over their energy usage. This includes offering or at least supporting the implementation of tools that enable customers to manage their energy consumption coupled with incentives that encourage responsible energy management. A successful smart grid implementation that has a focus on customer programs will rely heavily on customer participation to achieve increased grid efficiency, utilization, and customer satisfaction.

Under this scenario, interested and participating CWL customers will:

- Have access to and regularly evaluate their energy usage profiles/patterns/trends
- Adjust their energy usage patterns to minimize their costs and optimize grid efficiency simultaneously through dynamic rate structures such as Time-of-Use (TOU) and Peak Time Rebates (PTR)
- Invest in energy efficient appliances that can respond to price and demand reduction signals
- Participate in demand response programs such as critical peak pricing (CPP) and/or real-time rate structures
- Participate in Direct Load Control (DLC) programs such as central air conditioning thermostat temperature setback or compressor cycling
- Advocate energy conservation and participate in utility-sponsored social conservation initiatives
- Use two-way communications to directly share information with CWL and its customers

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

Utilities such as Salt River Project (SRP) in Phoenix, AZ, have demonstrated success with TOU rates and prepayment options for customers. SRP offers multiple voluntary TOU rate programs, in addition to a prepayment option for their customers. As of 2011, approximately 226,000 SRP customers were participating in TOU rate programs, or about 24 percent of their 940,000 customers. Additionally over 100,000 customers were participating in their M-Power pre-paid program. Dynamic pricing has also been a success for Arizona Public Service, which currently has 51 percent of its customers on various TOU rates. Dynamic pricing is expected to be marketed heavily at other utilities across the country including Baltimore Gas & Electric and Pepco in Maryland, followed by the Midwest (Illinois) utilities and California systems.

Some utilities across the country have piloted deployment of in-home displays (IHD) to customers in hopes that information and awareness alone would lead to load shifting, improved load factor, and energy conservation. These pilots have produced mixed results, some with little to no measurable change in customer energy consumption and others where significant impacts are identified immediately after deployment but those usage changes were not sustained by customers due to a lack of tangible incentive. Based on these results, it appears that IHDs alone may not provide a positive value proposition but may be effective tools when coupled with incentives for sustained behavior change such as dynamic rates.

3.2.2 CWL Assessment

CWL currently offers many programs for customer engagement and awareness, including a bill review and payment web portal, energy audits, efficiency rebates and a DLC program. CWL's website offers tips on conserving electricity and water, as well as information on xeriscaping and selecting the proper shade trees.

CWL does not currently offer any prepayment or dynamic rate programs to residential customers.

Figure 3.1: CWL Smart Grid Assessment Matrix – Customers

	Smart Grid Functionalities	CWL has Implemented	CWL is Considering	CWL should Consider
Customers	Customer Web Portal with Usage and Bill History	√		
	Time Varying Rates - Load Factor	√	√	
	Time Varying Rates - Demand Response		√	
	Direct Load Control Programs	√		
	Conservation Education & Tips	√		
	Interval Data Available to Operations/Engineering		√	

3.3 METERING

3.3.1 Industry Perspective

To improve operational efficiency, interval usage data, two-way communications with customers, and advanced distribution system awareness; many utilities are implementing advanced metering networks, often referred to as Advanced Metering Infrastructure (AMI). AMI includes sophisticated solid state meters coupled with a robust wireless network that allows utilities to capture enhanced data from meters quickly and remotely. The AMI metering infrastructure enables advanced functionality to utilities and facilitates increased communications and information delivery to their customers.

Advanced functionality from the use of advanced metering networks includes:

- More robust and precise customer usage data in intervals down to one hour or less, to be shared with customers and to provide detailed load information to personnel within the utility;
- Remote meter reading as well as on-demand reads and status checks to eliminate truck rolls;
- Remote connect and disconnect of electric service to customers to eliminate truck rolls;
- Automatic outage notifications to OMS, operators, and field crews;
- Enable time varying rate structures such as TOU and real-time pricing, to better align retail rates with the costs to generate or purchase power from wholesale markets; and
- Facilitate DLC/DR messages to electric customer displays and/or devices.
- Accurate evaluation and measurement of usage impacts from energy efficiency or demand response programs/events that may be used to settle market transactions or pay for performance.

While a complete AMI solution that includes new solid state meters at each customer location and a high bandwidth, two-way communication system that transmits information between the meters and the CWL service center can provide numerous benefits to the capability and precision of utility operations, it represents a significant investment for the utility.

While an AMI solution will accomplish all the above described functionality, ultimately, there are numerous ways for a utility to achieve each advanced feature regarding customer usage monitoring and measuring and service control. For example, modern AMR systems can provide precise consumption data at short read intervals; cellular or radio communication units on customer meters can enable remote interval and on-demand readings; communications from the CWL service center may be delivered to the customer via a web portal; and other solutions may be considered in lieu of implementing a full AMI solution.

Oklahoma Gas & Electric (OG&E) is a nearby utility that is deploying smart meters throughout their service territory. They have already installed over 790,000 smart meters that are actively collecting energy usage data from their customers and transmitting it to communication devices at scheduled intervals.

3.3.2 CWL Assessment

CWL currently utilizes a mixture of older electromechanical meters and newer solid state meters. Most new solid state meters and some electromechanical meters are equipped with ERT messaging. ERT messages are wireless messages transmitted a short distance from the meter on regular intervals that can be captured by a handheld or vehicle mounted device that is within range of the meter. CWL employs seven meter readers who read all CWL meters once a month through either visual readings or via close range capture of ERT messages with handheld McLite units.

CWL does not have a system-wide fixed metering network capable of capturing reads or notifications from electric or water meters, nor are any of their meters equipped with remotely controlled connect/disconnect switches.

Figure 3.2: CWL Smart Grid Assessment Matrix – Metering

	Smart Grid Functionalities	CWL has Implemented	CWL is Considering	CWL should Consider
Metering	Remote Connect/Disconnect			√
	Remote On-Demand Reads/Status			√
	Automated Outage Notification			√
	System & Subsystem Load Data	√		
	Fixed Network			√
	Interval Load Data on Each Customer			√

3.4 ELECTRIC DISTRIBUTION

3.4.1 Industry Perspective

Another integral component to a smart grid system is an advanced electricity distribution system that is remotely controllable and flexible to changing load conditions. This is accomplished primarily through increased monitoring, remote control, and automation of the distribution system assets.

Most utilities currently operate a sophisticated supervisory control and data acquisition (SCADA) system that communicates between the utility's control center and all, or at least most, of the primary devices within that utility's substations. However, utilities are only recently extending advanced monitoring and control to all devices within the substation and even to field devices beyond the substation such as capacitor banks, switches at feeder tie points, voltage regulators, and other devices. This is often referred to as Distribution SCADA (DSCADA) and usually involves the utilization of a wireless network to communicate to devices that direct fiber or copper connections cannot feasibly be made.

With established communications to all substation and field devices, sophisticated automation algorithms may then be explored that leverage coordination across the devices. Automation may be achieved through central or localized control systems.

Smart grid advanced distribution improvements commonly include:

- Remote monitoring and control of substation devices such as transformers, breakers, etc.;
- Remote monitoring and control of field devices such as capacitor banks, switches, reclosers, etc.;
- Data collection and logging of events at assets for health and performance evaluation;
- Increased utilization of system assets to maximize capital investments;
- Automated switching, fault location isolation and service restoration (FLISR);
- Volt/Var optimization on all circuits; and
- Accommodate integration of customer-owned distributed generation systems.

3.4.2 CWL Assessment

CWL operates robust electric and water distribution systems that reliably serve the City of Columbia and surrounding areas.

On the electric side, CWL has implemented a traditional SCADA system with remote monitoring and control of critical assets from the CWL control center. Critical assets currently monitored and controlled via SCADA include substation transformers, substation relays, and substation feeder breakers. Breakers at the power plant are also monitored via SCADA but are manually operated. CWL has load tap changers on most substation transformers but they are not remotely operable. CWL has also deployed some intelligent devices on select feeders outside of the substation such as some locally controlled variable capacitor banks that adjust to local load conditions and some capacitor banks that can be remotely operated through a one-way radio switch.

CWL could consider deploying remotely communicating or intelligent switches on distribution feeders that could shift load and isolate outages to small sections of customers. Ideally, these switches, along with additional measuring and sensing devices such as Fault Circuit Indicators (FCIs) and existing capacitor banks would be operated through a system-wide distribution SCADA (DSCADA) network(s) capable of remotely monitoring and operating all distribution field devices from a single user interface. This integrated and coordinated control could then enable more advanced functionalities and asset management such as those listed in Figure 3.3.

Figure 3.3: CWL Smart Grid Assessment Matrix – Electric Distribution

	Smart Grid Functionalities	CWL has Implemented	CWL is Considering	CWL should Consider
Electric Distribution	Volt/Var Optimization (VVO)		√	
	Dynamic Voltage Conservation (DVC)			√
	Conservation Voltage Reduction (CVR)			
	FLISR (Automated Sectionalizing)			√
	Remote Asset Monitoring & Control			√
	Condition-Based Maintenance		√	
	Transformer Monitoring/Rating			√
	Coordinated Protection Schemes			√
	Phasor Measurement Units			√
	Dynamic Cable Ratings			√

3.5 BACK OFFICE

3.5.1 Industry Perspective

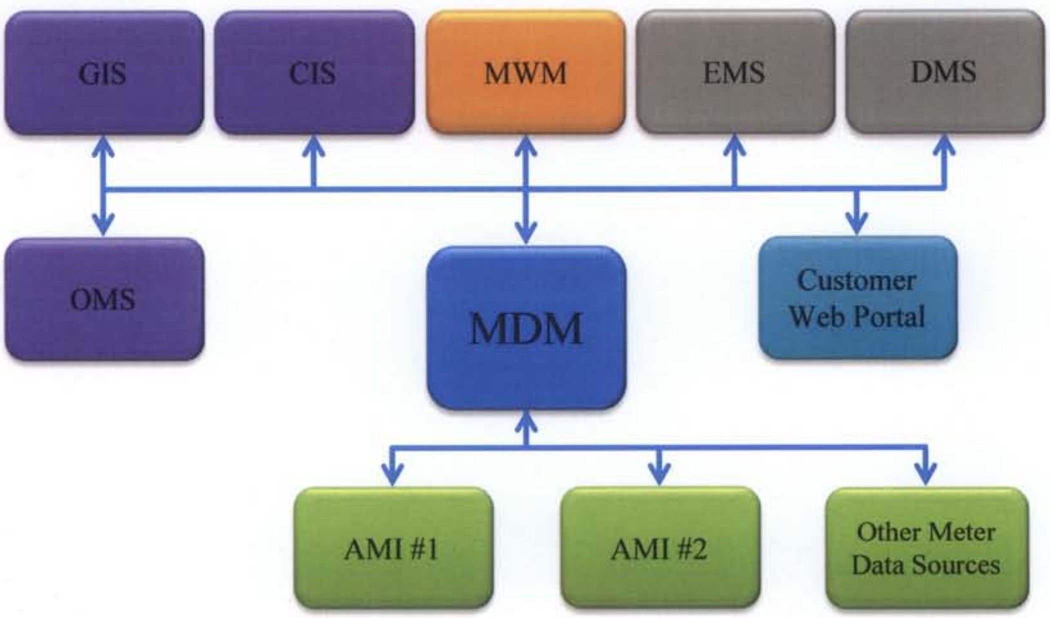
Smart grid technology deployments such as interval metering, distribution asset monitoring, and automation will produce significantly more data than utilities currently collect, manage, store and use. In order to make full utilization of these smart grid technologies, all relevant data should be readily available to utility personnel and interval usage data should be available to customers. Maximum utilization of these data requires an upgraded back office infrastructure that enables the following features:

- Real-time awareness of system and subsystem loads;
- Sharing of load and event information across departments and systems (integration);
- Load and event data analytics to enable optimization of operations and awareness;

- Customer data analytics to enable customer segmentation and optimize customer program designs;
- Customer access to their account and detailed usage information; and
- Robust metering and distribution asset management.

Advanced metering system providers are migrating towards standardized interval load data and event data formats that are designed to be processed through and stored in a MDM system and then integrated with other utility back office systems such as OMS, CIS, MWM systems, etc. This evolution is resulting in a MDM-centric architecture, shown in Figure 3.4, that is more flexible, provides back office systems and operators with a richer load and event repository, consolidates reads from multiple metering systems/networks, and enables other back office systems to focus on their primary functions.

Figure 3.4: Example MDM-Centric Utility Back Office Architecture



Advanced integration of an MDM can facilitate improvements in operational efficiency and significantly improve outage response times compared to legacy call-based systems. The cost to achieve these benefits is maintaining significantly more data, translations and integrations to keep these advanced functions operating. An MDM also provides a devoted system for capturing and storing usage data. This facilitates robust validating, estimating, and editing (VEE) of the collected data in a common methodology across multiple metering systems, if desired.

As detailed load data on each customer is amalgamated into an MDM, utilities have an opportunity to group customers into load-based segments and better design rates and programs that meet the customer's needs and preferences as well as improve overall load factor for a utility. It also becomes more feasible to equitably align individual customer rates with their true cost of service, thus shifting peak energy usage to off-peak periods allowing the utility to use its generation, transmission, and distribution assets more efficiently.

The smart grid also demands that customers become more involved in managing their own energy consumption in order to be responsible consumers of energy and to take full advantage of novel programs offered by utilities. In order to accomplish this, customers should be educated on the challenges associated with generating and delivering their electricity. Additionally, customers should have access to more detailed energy usage information so that they may make informed energy decisions such as energy management and conservation. Access to detailed usage information can be accomplished through an internet-based web portal and through other communication devices such as IHDs.

Most utilities are implementing or have already implemented advanced GIS that provide mapping and location of utility customers and system assets. When interfaced with other systems such as an OMS, advanced geographical analysis and visualization of relevant data is unlocked and the utility may benefit from more effective asset management, modeling, and operations.

A few utilities are piloting advanced Distribution Management Systems (DMS), similar to high-voltage Energy Management Systems (EMS), that provide monitoring, control, and coordinated automation to low voltage assets such as capacitor banks, reclosers/switches, feeder breakers, voltage regulators, etc. to provide advanced functionality such as volt/var optimization, FLISR, complex load shedding schemes, and integration of intermittent distributed generation. The value proposition for the advanced DMS is yet to be determined.

3.5.2 CWL Assessment

CWL shares numerous back office resources and IT personnel with the City of Columbia, including issuing electric and water utility bills to customers through a common Customer Information System (CIS). At this time, CWL and City of Columbia are in the process of evaluating numerous upgrades to their back office systems and infrastructure.

- Both the electric and water distributions system drawing and assets are being translated into GIS, although integration with other systems has yet to be determined;

- Current CIS does offer customers web-portal accounts with access to historical monthly usage and bill data with direct bill payments too, however, it cannot easily incorporate interval usage data from AMI. The City of Columbia is evaluating an upgrade to this system; and
- CWL's current OMS vendor, Milsoft, offers a proprietary GIS solution that integrates well with their OMS solution but does not easily integrate with all other GIS standards and formats nor does the Milsoft OMS offer upgrade or expansion to incorporate DSCADA for distribution dispatchers.

Figure 3.5: CWL Smart Grid Assessment Matrix – Back Office

	Smart Grid Functionalities	CWL has Implemented	CWL is Considering	CWL should Consider
Back Office	Systems/Data Integration			√
	Operational Data Logging & Trending			√
	Advanced Data Analytics			√
	Customer Segmentation & Target Marketing			√
	Compliance Tracking & Verification			√

3.6 COMMUNICATION SYSTEMS

3.6.1 Industry Perspective

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

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

Typically, the backbone network needs to be robust and reliable with high bandwidth availability to support smart grid applications. This is most commonly accomplished through a fiber optic network that connects the utility service center to all or at least most substations throughout the service territory. Across the industry, utilities are adding communications to substations and field devices that have those capabilities to enable real time information flow to operations centers. This allows for more informed decision making and optimization of the distribution system. Both fiber and wireless packet networks are being utilized to expand the office into the field and provide this functionality.

The "last mile" may utilize one or more of a variety of capable technologies and/or already existing networks. The selection and design of the "last mile" system(s) will depend on geography, application and cost.

3.6.2 CWL Assessment

CWL owns and operates an extensive fiber network throughout its service territory that connects all substations to the control center (see Appendix B). This fiber network is primarily used to transmit CWL SCADA traffic but also handles some City LAN/WAN traffic and dark fiber is leased to external entities for internet-only service. This fiber network should provide an adequate backbone to support the addition of new utility networks such as a wireless fixed metering network, wireless DSCADA network, or other distribution field networks to communicate with CWL field devices.

CWL has not yet implemented a fixed metering network, DSCADA, or distribution field network.

Figure 3.6: CWL Smart Grid Assessment Matrix – Communications

	Smart Grid Functionalities	CWL has Implemented	CWL is Considering	CWL should Consider
Comms	Fiber Backhaul Network	√		
	Transmission/Substation SCADA	√		
	Distribution SCADA			√
	Fixed Metering Network			√
	Distribution Field Network			√

3.7 SECURITY AND COMPLIANCE

3.7.1 Industry Perspective

Implementation of data intensive technologies along with additional networks creates new sensitive data and vulnerabilities. This data may consist of critical utility operational data and sensitive customer usage information. Both types, if left unprotected, can result in reliability and privacy risks if exposed.

A robust cyber security strategy should accompany implementations of smart grid technologies. This strategy should address not only deliberate attacks launched by disgruntled employees, agents of industrial espionage, and terrorists, but also inadvertent exposures due to user errors, equipment failures, and natural disasters.

There are currently no specific smart grid regulations in place that dictate security of smart grid-related applications, systems, and networks; however, regulations are being considered. A comprehensive set of cyber security guidelines have been published by the US Department of Commerce National Institute of Standards and Technology (NIST). Endpoint and system vendors are requested to comply with these guidelines in order to address remote access, authentication, encryption, and privacy of metered data, operational data, and customer information.

The three-volume report (NISTIR 7628 - Guidelines for Smart Grid Cyber Security) presents an analytical framework that organizations are using to develop effective cyber security strategies tailored to their particular combinations of risks and vulnerabilities. For example, for AMI systems, some of the security requirements are authentication of the meter to the collector, confidentiality for privacy protection, and integrity for firmware updates.

Development of the Guidelines for Smart Grid Cyber Security began with the establishment of a Cyber Security Coordination Task Group (CSCTG) in March 2009 that was established and is led by NIST. The CSCTG now numbers more than 475 participants from the private sector (including vendors and service providers), manufacturers, various standards organizations, academia, regulatory organizations, and federal agencies.

3.7.2 CWL Assessment

CWL does incorporate physical security measures at generating facilities, substations, and facilities but have not developed a robust cyber or physical security strategy.

CWL has not yet evaluated their systems and networks to evaluate compliance with NISTIR 7628 and are not required to do so. CWL has not yet developed a maintenance program aimed at achieving and sustaining compliance. This is something that should be completed in the near term if possible.

Figure 3.7: CWL Smart Grid Assessment Matrix – Security

	Smart Grid Functionalities	CWL has Implemented	CWL is Considering	CWL should Consider
Security	Robust Physical Security Strategy			√
	Robust Cyber Security Strategy			√
	Full NERC CIP Compliance (NISTIR)		√	
	NERC CIP Compliance Maintenance Program		√	

* * * * *

4.0 SMART GRID FUNCTIONALITY OPPORTUNITIES

BMcD's recommended approach to evaluating investments in smart grid technologies is to determine those smart grid functionalities that are of the greatest interest to CWL and that have the potential for the greatest return on investment. Upon prioritizing the desired functionalities, a technology implementation strategy and plan should be derived to prudently and responsibly achieve those functionalities. There has been a tendency in the industry to focus on the technologies first and then work to justify their implementation and business case.

4.1 SMART GRID FUNCTIONALITIES MENU

A number of functionalities exist within each of the smart grid categories outlined in the previous sections. These functionalities can be selected a la carte to support the utility's current and future needs. Figure 4.1 lists the relevant functionalities that CWL should consider. Each functionality is described in terms of the objective to be achieved and technology requirements. The objective of each functionality and the general technology requirements are discussed in the remainder of Section 4.

Figure 4.1: Smart Grid Functionalities Menu

CUSTOMERS

- Web Portal Access
- Time Varying Rates – Load Factor
- Time Varying Rates – Demand Response
- Direct Load Control Programs
- ZigBee Meter Communications
- Conservation Education & Tips

METERING

- Remote Connect/Disconnect
- Remote On-Demand Reads/Status
- Automated Outage Notifications
- System & Subsystem Load Data

TRANSMISSION & DISTRIBUTION

- Volt/Var Optimization
- Dynamic Voltage Conservation - DR
- Conservation Voltage Reduction
- FLISR
- Remote Asset Monitoring & Control
- Condition-Based Maintenance
- Dynamic Cable Ratings

BACK OFFICE

- Systems/Data Integration
- Operational Data Logging & Trending
- Advanced Data Analytics
- Data Visualization
- Cust. Segmentation & Target Marketing
- EM&V

4.2 CUSTOMER FUNCTIONALITIES

4.2.1 Web Portal Access

An energy usage web portal will provide customers with detailed personal usage and bill information through a web-based account interface. Energy usage data should be as detailed as is tracked and available by the utility: monthly, daily, hourly, 15-min, etc. Hourly interval data enables engaged customers to better understand and manage their energy usage and when coupled with incentives such as time-varying rates, helps them maximize savings. This requires the utility to interface their billing and metering data systems with a vendor or customized web portal system with customer direct access.

Technology Required:

- MDM (most energy usage web portals will be run off of an MDM, however a standalone system can be implemented that interfaces with a metering system or CIS only)
- System Integration

4.2.2 Time-Varying Rates – Load Factor

Rates such as TOU rates, PTR rates, and other less common options offer customers incentives and rewards to sustainably change their energy usage patterns and shift their load from system or subsystem peak times to off-peak times, thus improving the overall load factor of the utility's distribution system. This can help reduce system peak load growth and potentially defer significant investment in generation capacity or avoid purchasing expensive wholesale power to meet daily peak demand. These rates require the collection and aggregation of hourly interval usage data on all participating customers that can be achieved through interval data provided by AMI/MDM or legacy specialty TOU meters. Recent pilot studies show that customers with access to detailed energy usage data through a web portal or equivalent are more effective at shifting their load to off-peak time periods on average.

Technology Required:

- AMI or Specialty Meters
- CIS system capable of billing more advanced rates

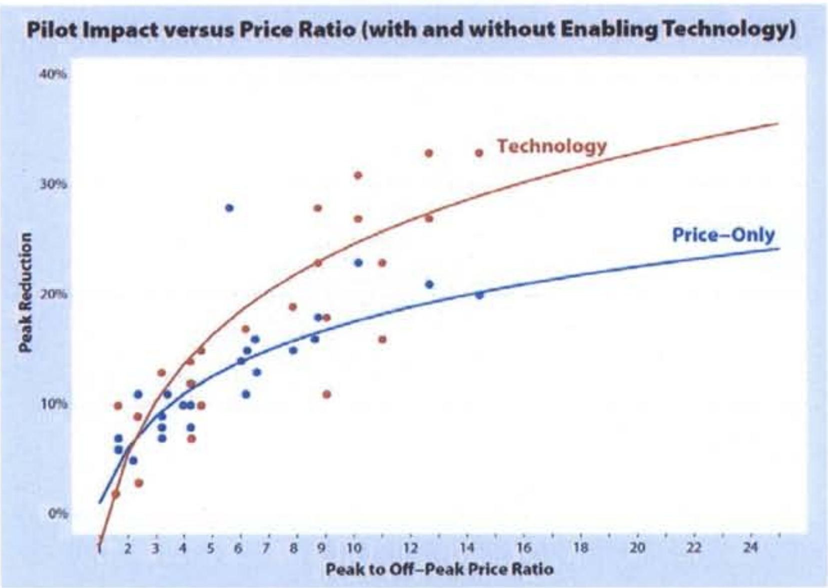
4.2.3 Time-Varying Rates – Demand Response

Rates such as CPP rates, CPR rates, and variable peak pricing (VPP) offer customers incentives and rewards for significantly shifting loads during select and critical peak events. These events and period load shifts can also save customers significantly on their bills and can help the utility maintain power quality and avoid overloads on the hottest peak load days of the year. Again, hourly interval data is generally required for participants and access to usage information improves customer effectiveness as shown in Figure 4.2. It is also recommended that the utility implement an event notification system to warn customers of event periods at least a day ahead.

Technology Required:

- AMI or Specialty Meters
- CIS system capable of billing more advanced rates

Figure 4.2: Time-Varying Rates Impact on Peak Load



Source: Time-Varying and Dynamic Rate Design, A. Faruqui, R. Hledik, J. Palmer, July 2012

4.2.4 Direct Load Control Programs

DLC programs achieve the same objective as demand response time-varying rates but on a more reliable basis. The most common customer DLC programs consist of PCTs. PCTs offer residential customers new advanced programmable thermostats to control their heating and cooling systems and also offer utilities with the ability to directly adjust the customer's load during critical peak events. This adjustment is either in the form of AC compressor cycling or a simple temperature set point adjustment (i.e. during hot days, the set point may be increased by 4-6 degrees Fahrenheit). Many modern advanced PCTs communicate with utility control systems via ZigBee wireless to the meter and then through an AMI network when present, but a majority of legacy PCT programs utilize one-way paging networks or the internet (Wi-Fi) to communicate. Often time, these legacy PCTs can only receive one-way commands and are not capable of return messaging.

Other loads may also be targeted for DLC programs such as pool pumps/heaters, electric water heaters, irrigation pumps, and others depending on availability in different regions and markets. Some utilities offer monthly incentives to customers for participating and complying with DLC programs while others have demonstrated success by simply offering the advanced thermostat as incentive enough to participate. The device itself, plus installation, and operational fees commonly exceed $400/participant for utilities to implement.

Technology Required:

- PCTs
- Communications network/path (AMI+ZigBee or dedicated network)

4.2.5 ZigBee Meter Data

ZigBee is a communication protocol for transmitting signals using a low-cost, low-power wireless mesh network within the home. ZigBee devices are used in various applications including home and building automation. Utilities may consider allowing customers to connect their ZigBee devices to compatible meters in order to receive ongoing energy consumption information for the premise to support the intended function of the device. For example, meters may provide devices with real-time demand and energy price information that ZigBee devices or customers may take action on to reduce their energy bill or environmental impact. Connecting devices such as these must be done in a secure manner to maintain the integrity of the utility grid.

Technology Required:

- AMI metering with ZigBee radio modules

4.2.6 Conservation Education & Tips

Conservation and industry education efforts can increase customer awareness of the impacts their energy consumption patterns have on utility operations and the environment, and may provide insight into how they can manage their consumption to save money on their utility bills. Education efforts can take many forms including energy audits, email campaigns, community events, monthly newsletters, online tips through interactive websites, bill stuffers, and smartphone apps.

Technology Required:

- No specific technology unless required for information delivery such as web portal but some level of data collection and analytics is required to evaluate the effectiveness of the campaigns

4.3 METERING FUNCTIONALITIES

4.3.1 Remote Connect/Disconnect

Remote connect/disconnect allows the utility to have greater flexibility and responsiveness to customer status changes. It significantly reduces truck rolls for connections/disconnections and provides an effective way to address inaccessible meters.

Technology Required:

- AMI
- System Integration

4.3.2 Remote On-Demand Meter Reads and Status Checking

Remote on-demand meter reads and status checking also significantly reduces truck rolls. The ability to verify meter status remotely allows the utility to provide better service to customers and identify issues quickly without rolling a truck.

Technology Required:

- AMI
- System Integration

4.3.3 Automated Outage Notifications

Automated outage notifications allow the utility to detect an outage before customers call in to report it. This helps the utility quickly pinpoint the location an outage has occurred, which can significantly reduce the time spent determining root cause for the outage and, in turn, reduce outage times.

Technology Required:

- AMI or Advanced AMR with messaging
- System Integration

4.3.4 System & Subsystem Load Data

Detailed system and subsystem load data can be viewed and monitored to assess the health of systems and subsystems and provide insight into planning for scheduled maintenance and upgrades.

Technology Required:

- AMI or Specialty Metering
- MDM and Analysis to aggregate sub-system loads

4.4 TRANSMISSION & DISTRIBUTION FUNCTIONALITIES

4.4.1 Volt/Var Optimization

Volt/Var optimization may appreciably reduce distribution losses on those circuits where it is applied. Through the coordination and automation of modern devices on feeders, significant improvements can be made in power quality and delivery efficiency through Volt/Var optimization. By implementing advanced communicating capacitor bank controllers, voltage monitors, voltage regulators, and FCIs with a communications network and central logic controller, a more uniform and specified voltage profile can be maintained along the entire length of the distribution primaries. Additionally, these technologies may better accommodate changes in reactive power demands and enable voltage conservation options.

Technology Required:

- Communicating Capacitor Bank Controllers
- Voltage Regulators (as required)
- Voltage Monitors (as required)
- FCIs (as required)
- Distribution Field Network (often referred to as Distribution Automation Network)

4.4.2 Dynamic Voltage Conservation – Demand Response

Utilizing the same technology as is required for Volt/Var optimization combined with integrated load tap changers (LTCs) at the substation transformers, utilities may safely reduce voltage on circuits while maintaining acceptable thresholds to the end of the circuit. This is commonly referred to as Dynamic Voltage Conservation (DVC). This functionality may be enacted as a demand reduction measure during periods of extremely high load to lessen impacts on distribution system assets and reduce peak power purchases.

Technology Required:

- Integrated Load Tap Changers (LTCs)
- Communicating Capacitor Bank Controllers
- Voltage Regulators (as required)
- Voltage Monitors (as required)
- FCIs (as required)
- Distribution Communications Network

4.4.3 Conservation Voltage Reduction

Similar to DVC, conservation voltage reduction (CVR) consists of the exact same actions and utilizes the same assets to reduce voltage on applied circuits. However, the objective is to safely reduce voltage all the time rather than only during periods of high load. This may reduce immediate impacts to system assets and reduce fuel consumption. However it will also reduce overall kWh delivered to customers.

Technology Required:

- Integrated Load Tap Changers (LTCs)
- Communicating Capacitor Bank Controllers
- Voltage Regulators (as required)
- Voltage Monitors (as required)
- FCIs (as required)
- Distribution Communications Network

4.4.4 Fault Location Isolation and Service Restoration

FLISR technology enables utilities to react quickly to isolate faults and reduce their impacts on service to customers. It consists of increased sectionalizing of circuits combined with central monitoring and control logic that quickly switches load between circuits to isolate faults to as few customers as possible. In its simplest form, FLISR consists of mid-circuit reclosers that are programed to quickly isolate downstream faults and restore power to the top half of the circuit. This is particularly useful and has significant impact on outage indices for utilities that have long lateral feeders that experience repeated downstream faults due to vegetation and weather. This can help a utility improve their SAIDI and CAIDI numbers and provide more reliable outage information to their customers.

Technology Required:

- Advanced Reclosers with Remote Monitoring & Control
- Distribution Communications Network

4.4.5 Remote Asset Monitoring & Control

Remote monitoring and control of devices such as capacitor banks, reclosers, and switches gives the utility the ability to view the status of assets in real-time. This significantly reduces truck rolls and can also enable proactive maintenance and outage avoidance.

Technology Required:

- Distribution Communications Network
- Communicating Device Controls
- Data Repository and Analysis Engine

4.4.6 Condition Based Maintenance

Condition based maintenance is the concept of performing maintenance activities on systems as the need arises, as opposed to a regularly scheduled interval. This can allow the utility to focus on the critical infrastructure pieces that need attention and effectively manage their resources. Condition-based maintenance relies on actively monitoring systems and assets closely, combined with data analysis to provide accurate information at an appropriate interval to indicate where problems are likely to occur.

Technology Required:

- Distribution Communications Network
- Field Assets with Remote Monitoring & Control
- Data Repository and Analysis Engine

4.4.7 Dynamic Cable Ratings

Real-time cable monitoring, primarily for underground cables, allows the utility to detect thermal changes and other environmental conditions that could indicate problems and measure performance. Monitoring cables at their weakest and most heavily loaded point allows for safe operations closer to operational limits rather than operating below theoretical limits that often include significant levels of contingency.

Technology Required:

- Cable Thermal Sensors
- Distribution Communications Network
- Data Repository and Analysis Engine

4.5 BACK OFFICE FUNCTIONALITIES

4.5.1 Systems/Data Integration

Breaking down the silos that exist in typical utility operations is an integral part of an effective smart grid implementation. Much of the benefit to be gained from a smart grid effort comes from the ability to collect and disseminate information across departments to enable more efficient operations and informed investment decisions.

Technology Required:

- Robust and Secure Enterprise Network
- Data Translation between Systems

4.5.2 Operational Data Logging & Trending

Data logging and trending can help a utility understand the large amount of data available through smart grid technology implementation. Using this data to monitor a system's health can allow the utility to plan for maintenance and upgrades on an as-needed basis, and proactively address issues before they present themselves as large failures. Data availability for analysis can also enable better sizing of equipment and quicker problem solving, resulting in operational efficiencies.

Technology Required:

- Data Repositories and Analysis Engine(s)
- System Integration

4.5.3 Advanced Data Analytics

The vast amount of data collected from smart meters and remote distribution monitoring is much more beneficial to a utility if it can be processed and analyzed in a useful manner. Some of the advantages of data analytics include theft detection, condition-based maintenance, and overload identification.

Technology Required:

- Data Repositories and Analysis Engine(s)
- System Integration

4.5.4 Data Visualization for Effective Operations

Dashboards and metrics scorecards can be created from operational systems and data repositories to provide decision makers with a real-time (or near real-time) visual representation of the health of the systems. This also facilitates the ability to assess the impacts of the information that is displayed.

Technology Required:

- System Integration
- Data Visualization Software

4.5.5 Customer Segmentation & Targeted Marketing

Understanding what types of customers are in a given service territory can help a utility better serve their customers. The Smart Grid Consumer Collaborative (SGCC) outlines five customer segments in the residential electricity market. Knowing whether one's service territory is primarily comprised of Concerned Greens, DIY & Save, or Traditionals can give the utility insight into what marketing campaigns to pursue. Customers may be segmented through load and demographic data, but preferably through both. Demographic data may be ascertained through customer surveys and data capture through customer service operations stored in a Customer Relationship Management (CRM) system.

Technology Required:

- MDM
- CRM

4.5.6 Evaluation, Measurement & Verification

Data that is received from smart grid technologies should be captured and analyzed to enable robust and objective evaluation of the technologies' impacts on customer load and customer satisfaction. This is commonly referred to as evaluation, measurement, and verification (EM&V) and is necessary to justify significant investments in technologies to stakeholders and ratepayers.

Technology Required:

- Data Repositories and Analysis Engine(s)
- System Integration

4.6 COMMUNICATION SYSTEM AND SECURITY & COMPLIANCE

Communications networks/systems and cyber security measures should be designed and implemented according to functionalities, technologies, and vulnerabilities introduced by implementation of smart grid.

4.7 FUTURE INTEGRATED SYSTEM DEVELOPMENT

A long-term consideration of many utilities that are evaluating infrastructure and technology upgrades under the smart grid umbrella is the advancement of a fully integrated system. This advanced fully integrated system will effectively connect, monitor and coordinate distributed energy resources such as generation facilities, energy storage facilities and controllable loads via intelligent control logic and communication networks. In doing so, the fully integrated system can act within a utility's system similar to a conventional power plant. The fully integrated system offers a broad variety of services to utilities, plant operators, public services, utility customers, electricity suppliers, and grid operators.

A key component of a fully integrated system is real time monitoring of distributed energy resources through robust networks. The fully integrated system requires intelligent equipment which is enabled through the development of smart grid monitoring and communications infrastructure.

In the end, the fully integrated system will integrate the operation of supply- and demand-side assets to meet net customer demand for energy services. It will make use of information technology, advanced metering, automated control capabilities, and energy storage assets. This concept will also treat long-term load reduction achieved through energy efficiency investments, distributed generation, and verified demand response on equal footing with supply capacity expansion. Thus, this approach extends the boundary of utility capacity investments through the meter, with its expanding communication and control capabilities, all the way to customer-side equipment.

* * * * *

5.0 CWL SMART GRID ROI ANALYSIS

5.1 ECONOMIC DRIVERS

The primary economic drivers for CWL to consider when evaluating investments in smart grid infrastructure upgrades include increasing operational efficiency, reducing operating costs, and reducing wholesale power purchase costs.

5.1.1 Operations

CWL currently employs numerous meter readers that manually visit each electric and water meter at least once each month to collect usage readings. A fixed metering network would eliminate the need to read meters manually and would also enable the collection of more granular usage readings and real-time status notifications.

CWL's service territory is comprised of almost 50 percent rental property. Current practice is to roll a truck each time a connect/disconnect service is needed. Smart meters with remote connect/disconnect capabilities could potentially significantly reduce the number of truck rolls.

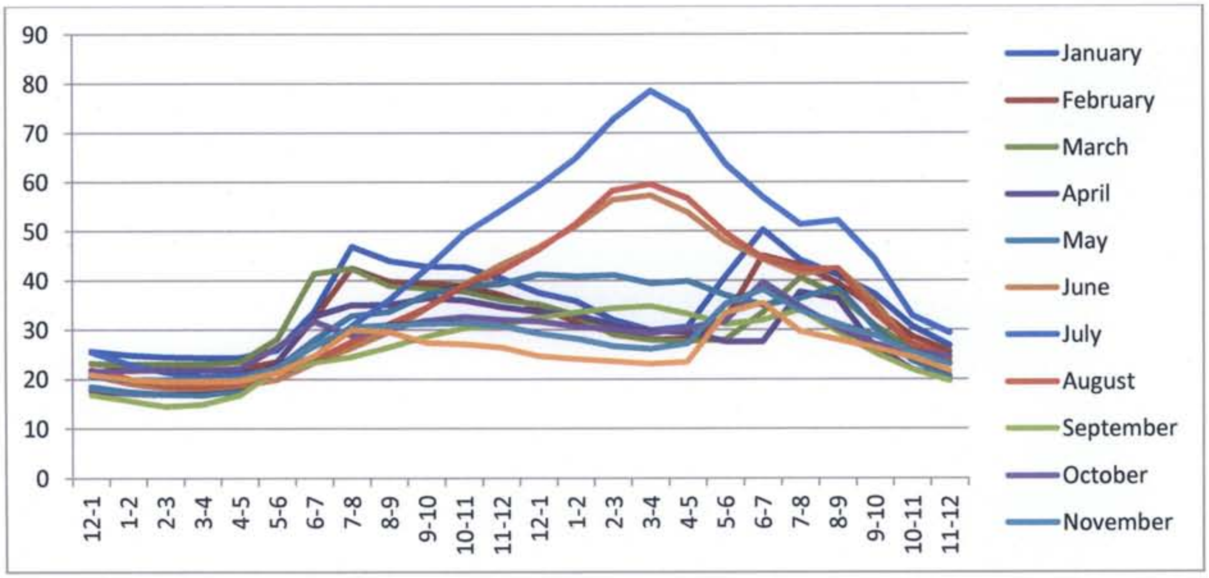
Remote monitoring and operation of distribution assets and devices will eliminate maintenance and outage truck rolls as well as enable more efficient restoration of device failures and other outages. This saves money on operations and reduces customer outage times, potentially increasing revenues.

5.1.2 Wholesale Power Rates

CWL purchases much of its energy from the MISO market. It sells energy from its generating resources into the MISO market, and uses the revenue from its energy sales to offset the cost of energy purchases. The ability to shift demand from peak hours to off-peak hours, through programs such as TOU, PCTs, and DVC, could allow CWL to purchase energy at a lower rate and potentially sell more energy at the higher peak prices.

In order to quantify the potential savings achievable by shifting demand from peak hours to off-peak hours, BMcD analyzed historical hourly day ahead LMP prices for CWL (Node CWLD.CWLD) for 2010, 2011, and 2012. The average peak LMP rate for TOU was determined by averaging the 5 peak LMP hours (1 PM – 6 PM) for all weekday, non-holiday summer days (June-August). See Figure 5.1 below summarizing 2011 monthly weekday LMPs. The off-peak LMP rate is the average of the remaining 19 off-peak hours during the same three summer months. Summary charts of summer weekday LMPs for all three historical years can be found in Appendix C.

Figure 5.1: 2011 Monthly Average Weekday LMP



Since PCTs and DVC are event based, the peak LMP rate for these programs was calculated by taking the average of the 5 peak hours (1 PM – 6 PM) on only the 20 worst summer days. The off-peak LMP rate for PCTs and DVC is the average of the off-peak hours on those same days. Table 5.1 provides a summary of the LMP analysis on the worst summer days for 2010-2012.

Table 5.1: 2010-2012 LMP Analysis

	5-hr Peak LMPs				Off-Peak LMPs			
	2010	2011	2012	AVG	2010	2011	2012	AVG
Top 08 Days Average:	83.51	94.83	95.62	**91.32**	42.42	45.09	35.01	**40.84**
Top 10 Days Average:	82.68	93.07	91.19	**88.98**	41.22	44.79	34.56	**40.19**
Top 15 Days Average:	80.19	87.33	82.02	**83.18**	40.16	42.77	33.23	**38.72**
Top 20 Days Average:	78.23	84.25	75.99	**79.49**	39.17	41.12	32.55	**37.61**
Top 30 Days Average:	74.69	77.38	67.57	**73.21**	37.24	38.46	30.73	**35.48**

5.2 IMPLEMENTATION SCENARIO #1: CWL-OWNED COMPREHENSIVE SOLUTION

The comprehensive implementation approach would involve full-scale replacement of all current meters with AMI meters and deployment of distribution system upgrades quickly in order to begin benefit realization as soon as possible. It would involve a significant capital investment upfront (likely over the first two years), but would ensure that all systems and assets were updated and coordinated to provide maximum efficiencies and savings.

Metering upgrades would consist of digital meters that are capable of two-way RF communications, sub-hour interval usage measurements, automated outage notifications, remote connect/disconnect, and in-home device communications (ZigBee). Distribution system upgrades include installing new capacitor bank controllers, feeder sectionalizing equipment, voltage regulators, and FCI's, as well as an associated wireless communications network.

This approach would also include integration of new and existing back office systems like CIS, GIS, OMS, MWM, AMI, and MDM. Robust integration enables maximum operational efficiency and automation while providing operators, engineers, and managers access to information and analysis to enable improved design and decision-making.

5.3 IMPLEMENTATION SCENARIO #2: VENDOR-HOSTED COMPREHENSIVE SOLUTION

The hosted solution approach provides equivalent functionality to the previously described comprehensive solution; however, a vendor provides a significant portion of the technologies and equipment to CWL as a service (similar to a leasing agreement) rather than a traditional capital expenditure. This approach provides CWL with the advantage of reducing upfront capital expense but can be more costly over the long term. The selected vendor would have the responsibility of funding and upgrading the meters and maintaining many of the back office systems. The utility simply pays a fee per meter per month for full service that usually includes AMI, MDM, and OMS. Additional services may be added for Asset Management. Upgrades to the transmission and distribution systems would be the same as Implementation Scenario #1.

5.4 IMPLEMENTATION SCENARIO #3: ENHANCED AMR APPROACH

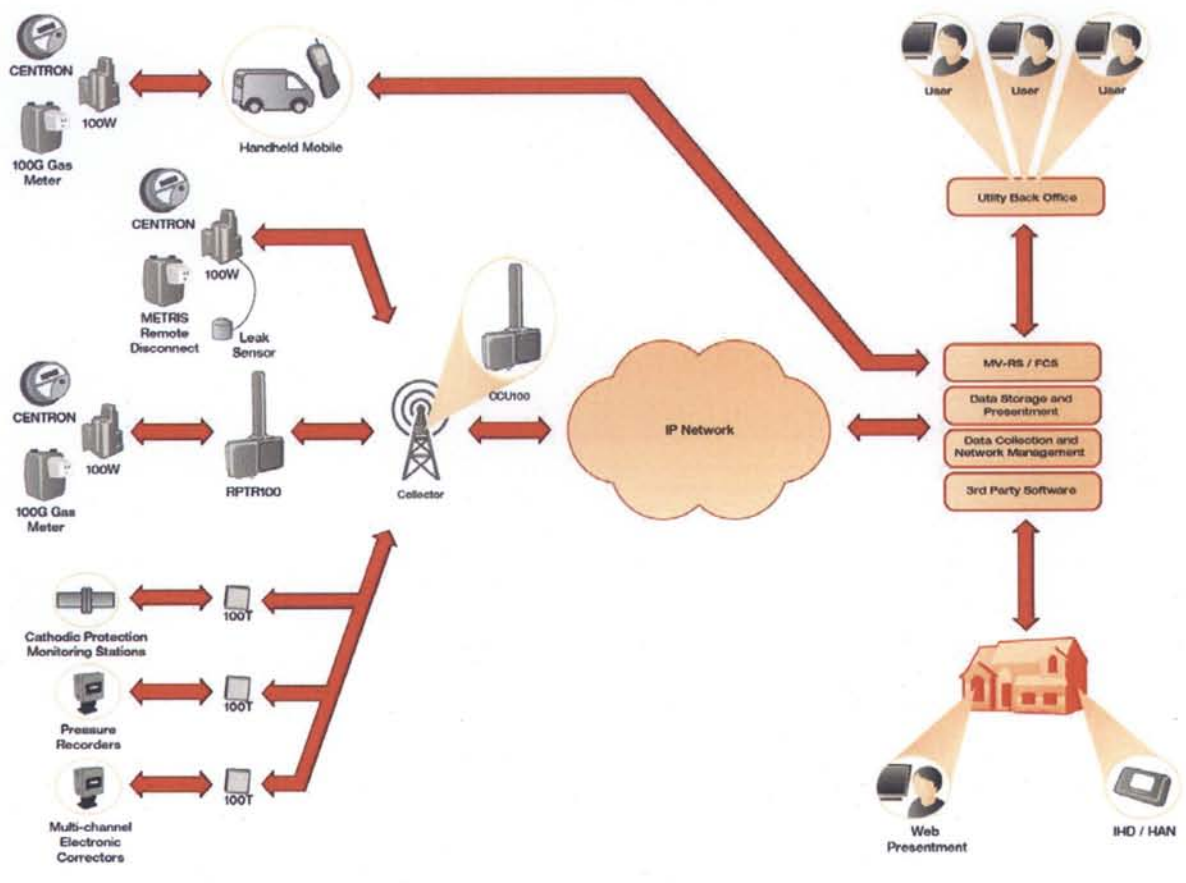
This approach would continue to utilize CWL's existing Itron digital meters with the addition of a compatible fixed network and MDM capable of capturing interval meter data. Distribution upgrades would be equivalent to the previous scenarios. This approach will limit capital investment in metering and enable full life utilization of the current Itron digital meters and enable installation of smart meters on a select and as-needed basis.

CWL's existing Itron meters have the capability to record interval data and report tamper detection. The Interval Data Message (IDM) delivered to the fixed network AMR system can be used to calculate ANSI standard demand, time-of-use, and load profile information. Itron's tamper detection is capable of identifying power removal, meter inversion, reverse disk rotation, and power outage counts. Additionally, CWL could install more advanced AMI meters selectively in areas they are warranted or for customers who sign up for programs and services that require them and these meters would operate seamlessly on a single fixed metering network.

For the fixed network, collectors and repeaters would need to be installed throughout CWL's service area to collect meter data and send it back to the office for processing. Figure 5.2 shows how the network would be structured.

Legacy meters would enable rates and analytics that depend on interval meter data but would not support two-way and ZigBee communications required for advanced devices in the home and AMI-based direct load control technologies and remote connect/disconnect. Select deployment of advanced smart meters would be required to enable these features.

Figure 5.2: Itron Fixed AMR Network Architecture



ChoiceConnect 100 Architecture

5.5 ROI SENSITIVITY ANALYSIS

To account for uncertainty in estimating costs and tangible benefit values, BMcD established *Nominal*, *Aggressive*, and *Conservative* case assumptions for each input into the analysis pro forma model. In general, the analysis represents a conservative approach to estimating costs and monetizing benefit value under *Nominal* case assumptions. The *Conservative* case assumptions provide even further confidence in ROI expectations developed in the analysis.

Additionally, the analysis was performed both with and without conservation programs taken into account. The first set of results assumes that CWL will pursue multiple demand side management programs enabled by these technologies including Dynamic Voltage Conservation (DVC = voltage reduction enabled by Volt/Var optimization upgrades), programmable communicating thermostats (PCT), and time-of-use rates (TOU). The second set of results assumes that CWL will not pursue these demand side management programs that tend to also result in customer conservation. This was done due to the fact that CWL's current MISO market rates offer little monetary benefit for demand reduction and all benefits are heavily outweighed by accompanying energy conservation by customers, reducing CWL sales and revenues significantly.

5.6 ROI ANALYSIS RESULTS

Costs estimated for this analysis include both capital and operating costs that were identified to achieve the functionalities and benefits sought by the technology upgrades selected. Costs for the various scenarios include upgrades to electric metering, back office systems, information technology infrastructure, and the CWL distribution system. The costs considered in this analysis are:

- DA Annual Capital Expenditures
- Advanced Meter Deployment Costs for Electric and Water Meters
- Network Installation Costs
- Fiber Integration & Upgrade for Backhaul
- Back Office/Data Management Costs
- PTC Program Costs
- TOU/TVR Implementation Costs
- Prepay Implementation Costs

The benefits to the adoption of smart grid objectives by CWL accrue to various parts of the Columbia community. These benefits may be realized by:

- CWL utility system

- CWL's customers
- The Columbia community

Direct benefits to CWL include increased operational efficiency, reduced operating costs, reduced losses, reduced energy purchase expenses, and increased revenues. The direct benefits considered in this analysis are:

- Operational savings from avoided AMR
- Revenue from increased electric and water meter accuracy
- Savings from reduced safety risk for meter reading
- Savings from a reduction in outage related calls
- Savings from reduced outage and connect/disconnect truck rolls
- Savings from reduced transformer oversizing
- Savings from reduced debt write-offs
- Savings from reduced energy losses, water losses, and theft losses
- Wholesale energy savings (conservation) from residential PCTs, residential TOU, and Volt/VAR optimization
- Peak energy savings from residential PCTs, residential TOU, and Volt/VAR optimization
- Deferred generation savings from residential PCTs, residential TOU, and Volt/VAR optimization

Annual net cash flow results, considering only direct benefits to CWL, for all three scenarios under *Nominal* assumptions are summarized in Figure 5.3 and Figure 5.4. A summary of ROI results for all three scenarios for direct benefits to CWL are shown in Table 5.2. More detailed results tables for the *Nominal* case for all three scenarios are included in Appendix D.

Table 5.2: Summary of ROI Results – CWL Direct Net Cost/Benefit

	Assumption Type	Scenario #1	Scenario #2	Scenario #3
With DSM Programs	**Aggressive**	$1,900,000	$(63,900,000)	$19,200,000
	Nominal	$(14,900,000)	$(77,300,000)	$9,700,000
	Conservative	$(31,400,000)	$(89,200,000)	$1,700,000
Without DSM Programs*	**Aggressive**	$3,700,000	$(62,300,000)	$20,200,000
	Nominal	$(10,700,000)	$(73,100,000)	$12,100,000
	Conservative	$(25,600,000)	$(83,400,000)	$5,000,000

** "Without DSM Programs" cases exclude revenue losses associated with customer conservation from DSM programs*

Figure 5.3: ROI Results of Direct Benefits to CWL with Conservation

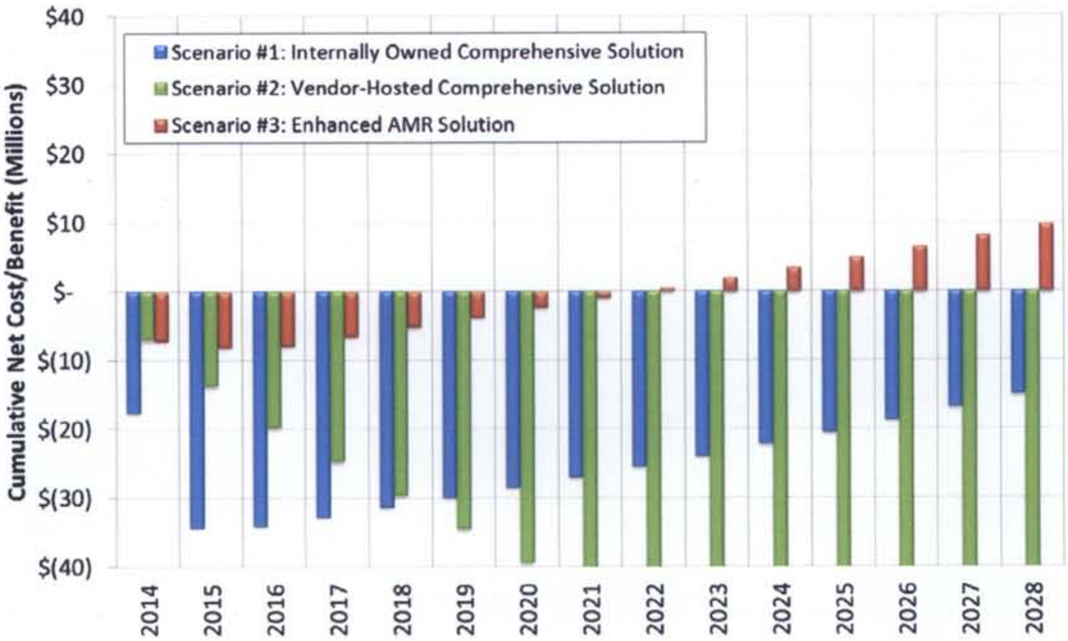
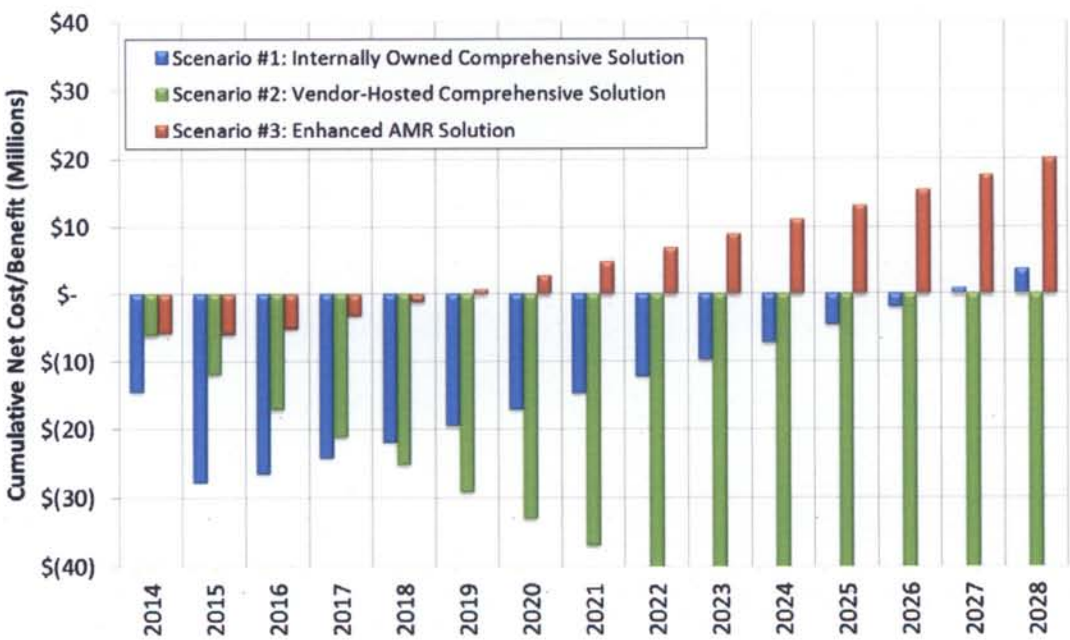


Figure 5.4: ROI Results of Direct Benefits to CWL without Conservation



When considering only benefits directly attributable to CWL, Scenario #3 results in a positive payback within the 15 year analysis window for all cases. Scenario #1 represents the largest near term investment for CWL and could result in positive cash flows after implementation in the *Aggressive* case, but not in the *Nominal* or *Conservative* cases. Scenario #2 does not appear to result in annual positive cash flow after implementation in any case. Additional operations and maintenance burdens associated with the new systems are projected to outweigh operational and direct financial benefits.

CWL's customer benefits in this analysis are:

- Customer savings from Volt/VAR optimization
- Customer savings from residential PCTs
- Customer savings from residential TOU
- Customer savings from residential prepay

Annual net cash flow results, considering both direct benefits to CWL and benefits to customers, for all three scenarios are summarized in

* "Without DSM Programs" cases exclude revenue losses associated with customer conservation from DSM programs

Figure 5.5 and Figure 5.6. A summary of ROI results for all three scenarios with customer benefits along with direct benefits to CWL are shown in Table 5.3. More detailed results tables for the *Nominal* case for all three scenarios are included in Appendix D.

Table 5.3: Summary of ROI Results – CWL and Customers Net Cost/Benefit

	Assumption Type	Scenario #1	Scenario #2	Scenario #3
With DSM Programs	**Aggressive**	$18,700,000	$(47,100,000)	$34,700,000
	Nominal	$500,000	$(61,800,000)	$23,800,000
	Conservative	$(17,700,000)	$(75,500,000)	$14,000,000
Without DSM Programs*	**Aggressive**	$7,800,000	$(58,200,000)	$24,300,000
	Nominal	$(7,100,000)	$(69,600,000)	$15,700,000
	Conservative	$(22,700,000)	$(80,500,000)	$7,900,000

* "Without DSM Programs" cases exclude revenue losses associated with customer conservation from DSM programs

Figure 5.5: ROI Results of Benefits to CWL and Customers with Conservation

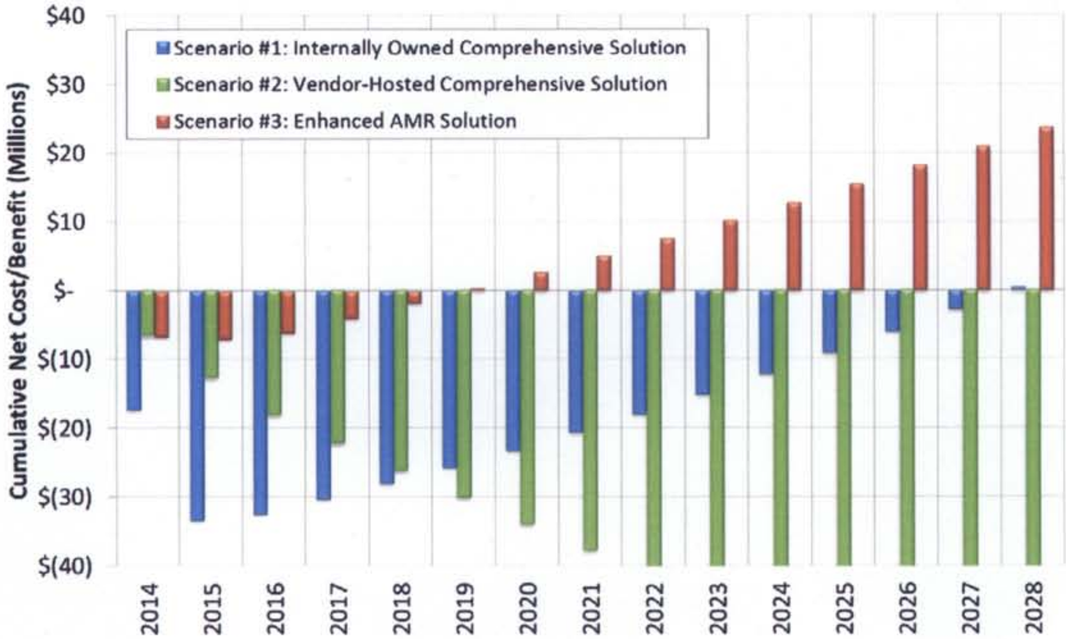
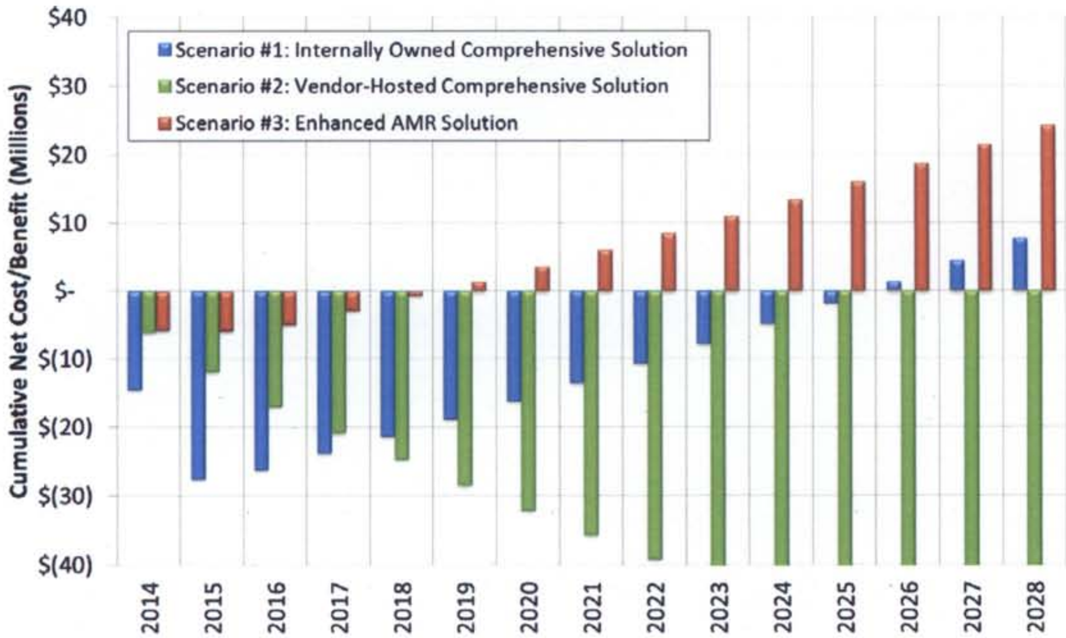


Figure 5.6: ROI Results of Benefits to CWL and Customers without Conservation



When estimated benefit values to customers are considered in addition to direct operational and financial benefits to CWL, Scenario #3 shows a payback period of less than 10 years for all cases. Scenario #1 has a positive payback for some cases, but not all cases. However, Scenario #2 continues to show negative cash flows for all cases.

In all assumption cases, Scenario #2 Vendor-hosted Solution is expected to result in a negative return on investment. Based on the information available, including estimated costs from vendors, BMcD calculates that the costs outpace the benefits on a recurring annual basis. Despite significant recurring annual costs associated with the hosted-solution, there are some notable benefits that BMcD fells should be thoroughly considered. Those benefits include:

- Quick deployment and conversion to new systems as the hosted environments are already established and don't require extensive customization, installation or testing
- Reduced need to acquire personnel with new skill sets needed to operate and maintain new systems
- Single point of contact and payee to address numerous systems
- Experienced vendor support on redesign of business processes to align with new systems

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

* * * * *

6.0 CWL SMART GRID RECOMMENDATIONS

Although many utilities across the country are investing heavily in smart grid and distribution system upgrades to implement data-centric architectures and increase automation, many appear to be struggling to fully achieve expected efficiencies and monetize the sought-after benefits from these investments. BMcD believes many of the challenges emerging with monetizing these benefits are primarily due to inaccurate cost and benefit expectations and a lack of utility personnel readiness to adapt and embrace the necessary operational transformations associated with these large infrastructure upgrades and associated process changes.

This business case analysis has assessed CWL's current infrastructure and technology utilization and has identified a number of investments CWL could consider to improve operational performance and efficiency. These upgrades could also enable CWL to more effectively manage generation and wholesale power costs to meet customer usage and demand.

Based on the quantitative and qualitative results of this business case analysis, **BMcD has identified the following notable observations**:

- Direct payback to CWL within 15 years is not expected from a comprehensive investment in smart grid technology upgrades. Estimated ROI results are variable due to some uncertainty in overall upgrade costs and the resulting benefit values (and the ability to monetize them).
- These smart grid upgrades have the potential to provide CWL customers with significant benefits in the form of increased availability of information, increased service reliability, and bill savings opportunities. However, it is unclear if the CWL customer base would embrace and capitalize on these opportunities, if offered.
- A number of benefits of AMI may be achieved through the implementation of a fixed metering network in conjunction with CWL existing meters and an MDM. Manual meter reading and truck-driven AMR could be eliminated from operations and interval metering data collection on select customers could be achieved.
- Back office and IT upgrades and integrations are required to support many of these technologies and represent a significant portion of the costs. Since CWL has a relatively small customer base, economies of scale may be hard to achieve on expensive infrastructure and back office investments. Cost and complexity for these upgrades and integrations are equivalent regardless of number of customers and therefore may cost more on a per customer basis for a moderately sized utility like CWL.

- Based on CWL's recent historical MISO LMPs, DR and peak shaving programs such as direct load control thermostats and dynamic rates may not provide sufficient peak generation or wholesale savings to cover their costs and potential loss of overall revenue due to expected collateral energy conservation that results from such programs.
- Although DR programs result in consumer conservation that negatively impacts CWL financial performance, the conservation results in significant benefits to CWL customers.

Considering the ROI analysis results and the above observations, **BMcD concludes the following**:

- In the near-term (the next 12 months), BMcD does not believe that CWL should commit to any large scale investments in comprehensive smart grid upgrades and operational transformations. The return on investment direct to CWL cannot confidently be achieved as the technologies are relatively immature leading to some uncertain costs to implement, especially at moderately sized utilities. Additionally, full monetization of the potential benefits will require significant organizational, cultural, and behavior change on behalf of CWL personnel, stakeholders, and customers.
- Although these investments currently represent significant financial risk, BMcD recognizes that the cost and benefit values associated with them will most-likely change quickly over the next three to ten years and should continue to be evaluated on a regular basis.

As CWL continues to provide reliable service to its customers and plan for future investments in their assets and operations, **BMcD recommends the following**:

- CWL should begin placing greater emphasis on educating customers and personnel about the ongoing challenges and emerging opportunities in the industry. The future of the electric industry and customer interests are expected to evolve to a more complex environment that will require robust data-centric infrastructure. As such, CWL should begin to gauge customer interests in adopting available technologies such as having access to interval usage data (through a web portal), advanced energy management technologies, and dynamic and non-standard rate options that incent behavior change, offer savings potential on electricity bills, and also benefit utility cost of service.
- CWL should begin examining efforts to increase foundational back office data quality and integration. In particular, operations and outage response performance could immediately benefit from integration of GIS data to existing OMS and Asset Management Systems in addition to preparing for future AMI, MDM, and DSCADA systems.

- CWL should immediately evaluate the costs and feasibility of implementing a fixed metering network that is compatible with CWL's current electric meters and is capable of supporting more advanced smart meters as well. This specific upgrade could provide CWL with some immediate benefits, provide CWL personnel with valuable experience as industry technologies evolve, and enable an alternative, albeit slower, transition path toward full-scale AMI deployment. BMcD believes that CWL' current metering technology provider, Itron, is able to provide such a fixed network.
- CWL should consider further evaluation of various DA technologies. Significant operational savings may be realized by enabling remote operation of substation and field devices and reducing distribution losses on both the electric and water systems. Enhanced operational awareness and flexibility could also improve reliability.
- CWL should consider conducting a thorough cyber security threat and vulnerability evaluation and gap analysis relative to the guidelines of NISTIR 7628 - Guidelines for Smart Grid Cyber Security. Subsequently, CWL should consider developing a cyber security strategy to address or mitigate known risks.
- Evaluation of future infrastructure investments at CWL should assess each investment's role in the development of a diverse and robust portfolio of distributed energy resources that could be aggregated into a fully integrated system (see Section 4.7).

BMcD believes many of the infrastructure upgrades associated with the smart grid industry movement bear significant value potential. However, it is not clear if this heavily regulated and monitored industry will be capable of quickly converting that potential into tangible stakeholder and customer value. At a minimum, operational transformations on this scale require robust executive commitment in order to be successful. It is also important to note that many of the sought-after benefits are dependent on customer engagement and behavior changes that must be incented, accommodated, and maintained adequately.

* * * * *

APPENDIX A

DOE FUNDED SMART GRID PROJECTS IN THE MIDWEST

Table A.1: Smart Grid Projects Funded by ARRA in the Midwest

Project	Grant Award Amount	Total Project Value	Description
Ameren Services Company	$5,679,895	$9,200,000	Ameren's Smarter Workforce Training Program addresses three Smart Grid areas: advanced distribution management systems (ADMS), a new geographic information system (GIS), and other smart devices for electric distribution systems. As a part of their training process, Ameren identifies key users who will receive additional training as instructors. This approach builds instructor credibility and enables these instructors to share their knowledge at their work sites. Ameren fosters a culture of continuous feedback to increase the effectiveness of their training and ensure student learning. Key stakeholders validate training materials, processes, and delivery methods during pilot training sessions. Ameren uses the Kirkpatrick model to evaluate training programs by targeting student satisfaction, learning, application of knowledge and skills gained, and track results, such as improved morale, return on investment, increase in sales/production, and increased customer satisfaction
City of Fulton, MO	$1,527,641	$3,174,962	The City of Fulton, Missouri, (Fulton) Smart Grid project involves installing new smart meters for all residential, commercial, and electric meters inside city limits; supporting communication infrastructure; and offering advanced electricity service options for customers across its entire customer base. The project includes: (1) implementing two-way communication and utility applications to enable customers to view their electricity consumption at their convenience through the customer's Web portal, and (2) implementing time-based rate programs that allow customers to better manage their electricity usage and costs.
City of Naperville, IL	$10,994,110	$21,988,220	The City of Naperville (Naperville) Smart Grid Initiative project involves a city-wide deployment of an advanced metering infrastructure (AMI) and an expansion of distribution automation capabilities, which includes circuit switches, remote fault indicators, and smart relays. Customers are allowed to purchase devices that assist in managing electricity use and costs, including in-home displays, programmable communicating thermostats, and direct load control devices for participation in load management programs. This project allows: (1) participants to view their energy use through in-home displays, a Web portal, or both; and (2) Naperville to manage, measure, and verify targeted demand reductions during peak periods. The new AMI and distribution automation technologies are intended to help improve service quality and reliability, by enabling outage management, distribution circuit monitoring, and automated circuit switching.

Project	Grant Award Amount	Total Project Value	Description
Eastern Nebraska Public Power District Consortium	$1,874,994	$3,749,988	The Eastern Nebraska Public Power District Consortium's (Consortium) Smart Grid Initiative includes wireless communications, supervisory control and data acquisition software (SCADA), distribution automation software , intelligent reclosers and controls, automated regulator controls, and irrigation load control devices. The project implements two-way communications, SCADA, and distribution automation applications to allow the Consortium to (1) automate substations, (2) integrate new distribution automation equipment, (3) provide increased system visibility for customer outages, and (4) reduce operations and maintenance costs. Existing irrigation load control devices for the Cuming County Public Power District (CCPPD) are being upgraded, enhancing demand response and peak load reduction capabilities.
Iowa Association of Municipal Utilities	$5,000,000	$12,531,203	The Iowa Association of Municipal Utilities (IAMU) Smart Grid Thermostat project involves the deployment of advanced metering and customer systems for five participating municipal utilities. The project aims to reduce customer electricity costs, peak demands, and utility operating costs. The project deploys about 5,450 smart meters, 13,800 programmable communicating thermostats, and direct load control devices to: (1) allow customers to view and control their energy consumption at their convenience through a Web portal, and (2) allow the participating utilities to manage, measure, and verify targeted demand reductions during peak periods.
Kansas City Power & Light	$23,940,112	$49,830,280	Kansas City Power & Light and its partners is demonstrating an end-to-end SmartGrid —built around a major Smart Substation with a local distributed control system based on IEC 61850 protocols and control processors—that includes advanced generation, distribution, and customer technologies. Co-located renewable energy sources, such as solar and other parallel generation, will be placed in the demonstration area and will feed into the energy grid. The demonstration area consists of ten circuits served by one substation across two square miles with 14,000 commercial and residential customers. Part of the demonstration area contains the Green Impact Zone, 150 inner-city blocks that suffers from high levels of unemployment, poverty, and crime. Efforts in the Green Impact Zone will focus on training residents to implement weatherization and energy efficiency programs to reduce utility bills, conserve energy, and create jobs. KCP&L's SmartGrid program will provide area businesses and residents with enhanced reliability and efficiency through real-time information about electricity supply and demand. It will enable customers to manage their electricity use and save money.
Midwest Energy	$712,257	$1,424,514	Midwest Energy (Midwest) is deploying new smart relays at its Knoll transmission substation. These relays include synchrophasor measurement technologies that can increase grid operators' visibility of bulk power system conditions in near real time, enable earlier detection of problems that threaten grid stability or cause outages, and facilitate sharing of information with neighboring control areas. Having access to better system operating information allows Midwest to improve power system models and analysis tools, increasing reliability of grid operations.

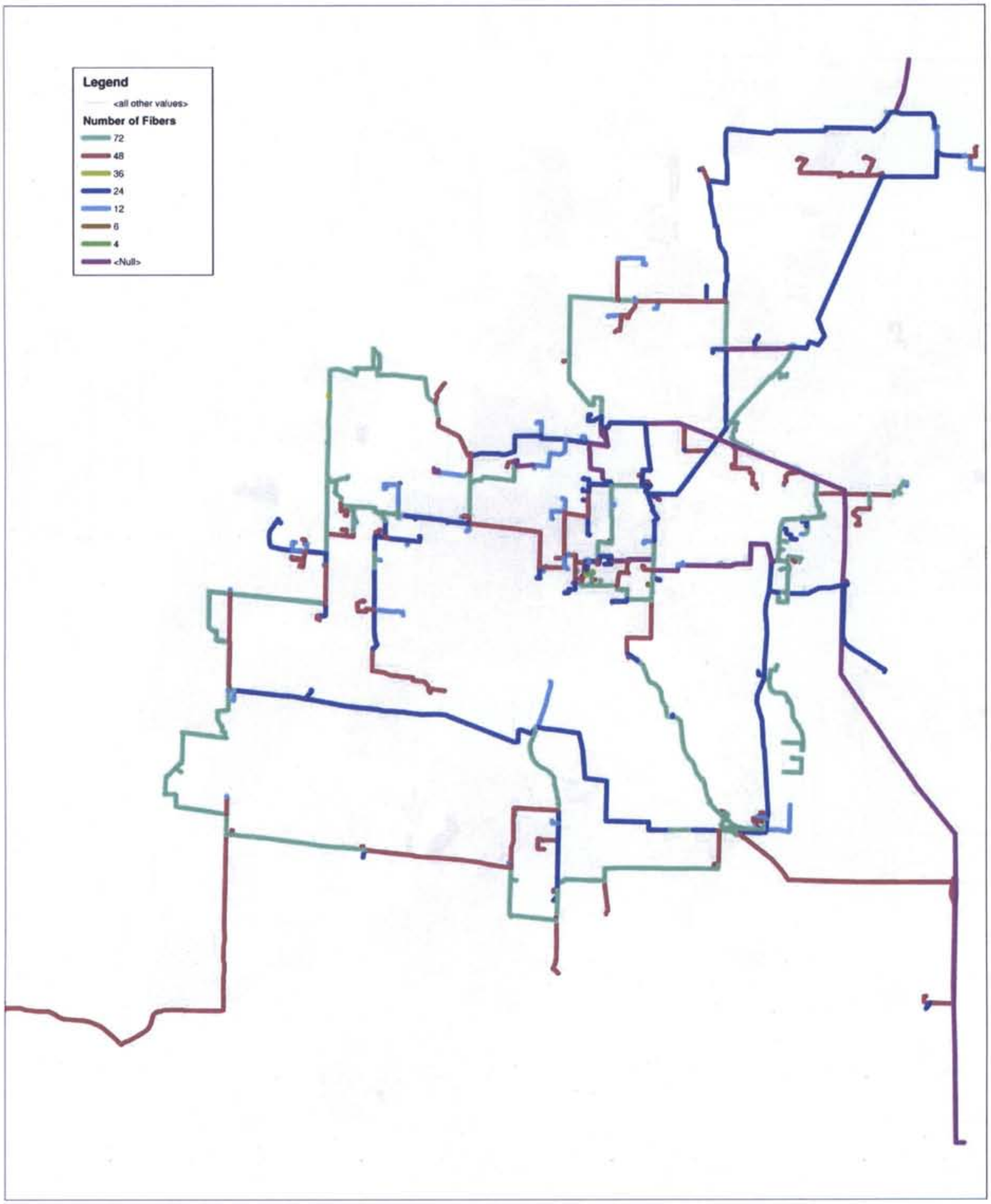
Project	Grant Award Amount	Total Project Value	Description
Midwest Independent Transmission System Operator	$17,271,728	$34,543,476	The Midwest Independent Transmission System Operator (Midwest ISO) is deploying synchrophasor technology throughout its service footprint. Midwest ISO's primary objective is to use the technology to optimize the dispatch and operation of power plants while improving the reliability of the bulk transmission system. This project deploys phasor measurement units (PMUs), phasor data concentrators, and advanced transmission software applications. This technology increases the visibility of grid operators' bulk power system conditions in near real time, enables earlier detection of conditions that could result in grid instability or outages, and facilitate information sharing with neighboring regional control areas. Access to better system operating information allows Midwest ISO engineers to improve power system models and analytical techniques, improving the overall reliability and operating efficiency of the Midwest ISO system.
Oklahoma Gas & Electric Company	$130,000,000	$357,376,037	The Oklahoma Gas and Electric (OG&E) program involves system-wide deployment of a fully integrated advanced metering system, distribution of in-home devices to almost 6,000 customers, and installation of advanced distribution automation systems. The program is a partnership with customers, aimed at reducing peak loads, overall electricity use, and operations and maintenance costs while increasing distribution system efficiency, reliability, and power quality. The program implements secure wireless communications to: 1) allow smart meter customers to view their electricity consumption data at any time through a personalized Web site (study participants are testing other visual displays), and 2) allow OG&E to manage, measure, and verify targeted demand reductions during peak periods. New systems capture meter information for billing and implement new customer pricing programs and service offerings. The project deploys a more dynamic distribution management system, automated switching, and integrated voltage and reactive power control (IVVC) that reduces line losses, reduces operational costs, and improves service reliability. The program also includes a study of consumer behavior in response to different forms of dynamic pricing and home area network smart technology on an opt-in basis. Finally, the program includes collaboration with University of Oklahoma faculty and students to deploy technologies within 46 buildings on the Norman, Oklahoma, campus and to take advantage of opportunities for education and training.
Stanton County (NE) Public Power District	$397.000	$794,000	Stanton County Public Power District's (SCPPD) Advanced Metering Infrastructure Initiative project deploys 2,315 smart meters to cover all customers in the service territory. The project provides automatic meter reading and improved outage detection and response. The project extends smart meter coverage from 453 to 2,768 meters and uses existing radio frequency and power-line-carrier communications networks for data collection.

Project	Grant Award Amount	Total Project Value	Description
The Boeing Company	$8,561,396	$17,172,844	Boeing and its partners will demonstrate the benefits of advanced Smart Grid technologies and concepts for optimizing regional transmission system planning and operation by enabling wide-area situational awareness, coordination, and collaboration in a secure manner. Using historical playback data from Regional Transmission Organizations and utilities, Boeing will run a baseline scenario and multiple off-baseline scenarios to demonstrate improvements in transmission operators' ability to address current challenges like load congestion and artificial seams between control areas, as well as emerging stressors, including increased generation of intermittent renewable energy. Test cases will be derived based upon challenges experienced during typical operations, day-ahead planning, peak load conditions, intermittent energy operations / large swings in supply and demand, significant unforeseen failure events, and cyber-attack. The project team includes leading regional transmission organizations and utilities that serve all or part of 21 states and more than 90 million people. This project is differentiated by its ability to leverage network architecture and military-grade cyber security experience and capabilities that are scalable and enable interoperability with both legacy systems and new Smart Grid technologies. Team members will also develop public outreach and education programs to raise awareness of Smart Grid benefits.
Westar Energy	$19,041,565	39,290,749	Westar Energy's SmartStar Lawrence project deploys advanced metering infrastructure (AMI), meter data management system (MDMS), and distribution automation equipment. AMI and MDMS systems are expected to reduce operating costs, improve reliability, and enhance customer services by improving enterprise systems, including billing, outage management, and load research. The AMI and MDMS also support a customer Web portal that provides energy usage and billing information for customers. Distribution automation assets include automated reclosers, capacitor automation equipment, and fault indicators to speed up restoration of service following outages and reduce energy losses through improved management of circuit voltages.
Woodruff Electric Cooperative	$2,357,520	$5,016,000	Woodruff Electric Cooperative's (Woodruff) Advanced Metering Infrastructure (AMI) project provides two-way communicating smart meters to all of its residential customers and selected commercial customers. The primary objective of the project is to gain efficiencies related to metering operations. The AMI system provides time-of-use data, outage information, and distribution load data, which is used to improve system reliability. In addition to the meters, Woodruff provides remote disconnect/reconnect switches that operate on the same existing power line carrier infrastructure as the smart meters and allow for bill prepay options for customers, remote firmware upgrades, and remote demand reset.

APPENDIX B

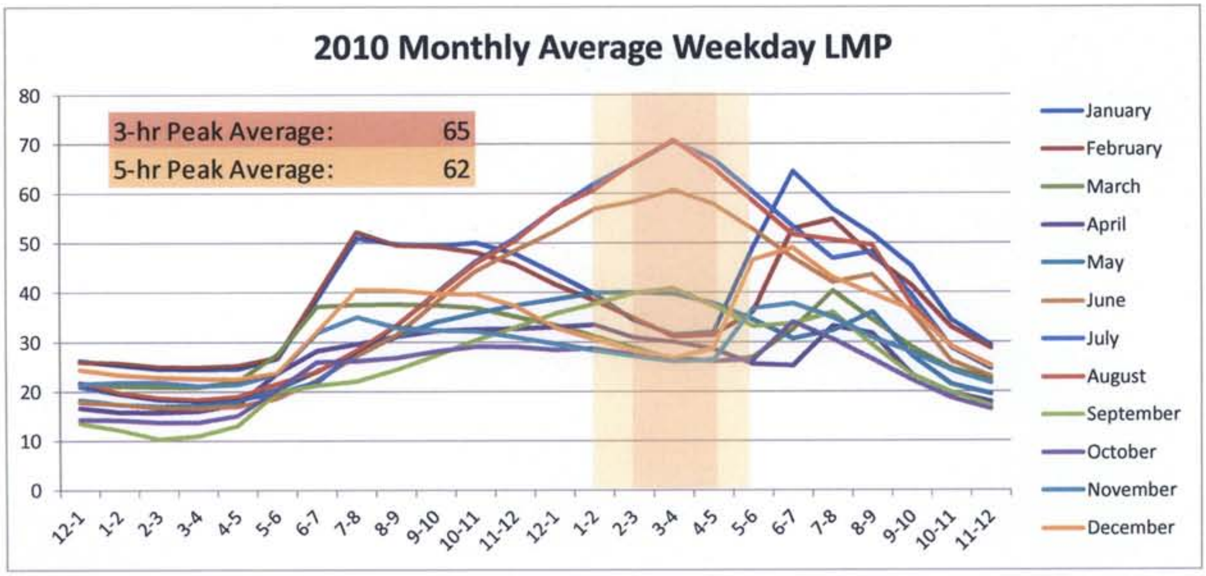
CWL FIBER NETWORK

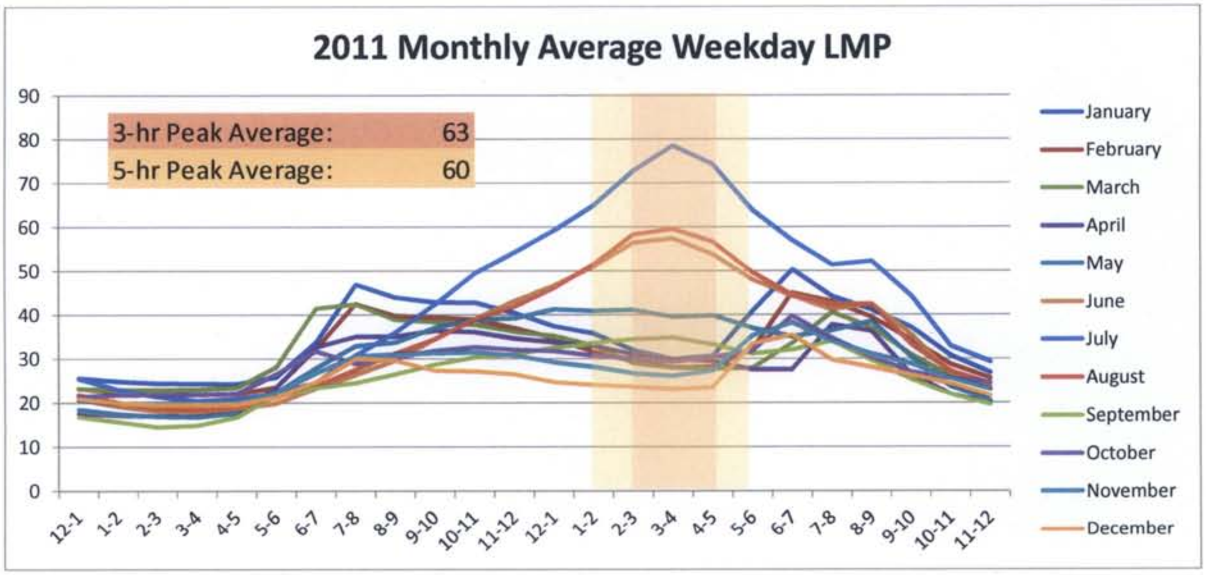
CWL's fiber network as of 2012:

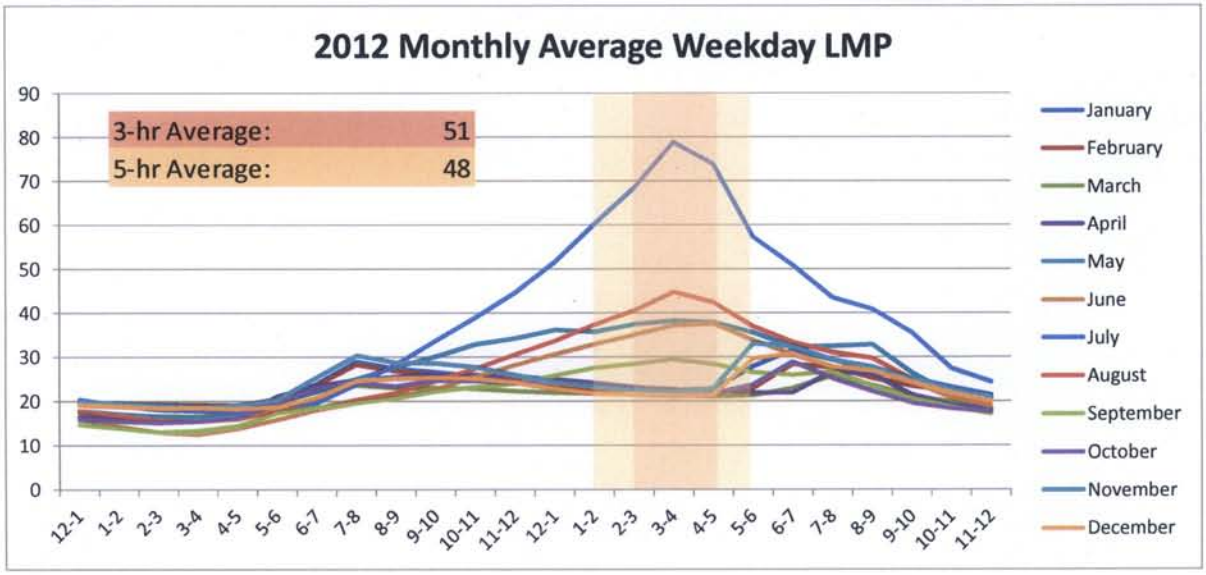


APPENDIX C
HISTORICAL MONTHLY AVERAGE WEEKDAY LMP FIGURES

CWL Historical LMPs:






2012 Monthly Average Weekday LMP
3-hr Average: 51
5-hr Average: 48
90
80
70
60
50
40
30
20
10
0
12-1 1-2 2-3 3-4 4-5 5-6 6-7 7-8 8-9 9-10 10-11 11-12 12-1 1-2 2-3 3-4 4-5 5-6 6-7 7-8 8-9 9-10 10-11 11-12
January
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May
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November
December

APPENDIX D

PRO FORMA RESULTS FOR NOMINAL CASES

Nominal Case - With Demand Side Management Programs

Economic Impacts from Smart Grid Implementation and Enhanced Operations - COMPREHENSIVE APPROACH - INTERNALLY DEPLOYED/OPERATED (Scenario 1)

COSTS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
DA Annual Capital Expenditures (Scenario 1)	$ 1,040,102	$ 1,386,803	$ 1,040,102	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 4,299,090
Advanced Meter Deployment Costs (Scenario 1) - Electric	$ 3,910,073	$ 3,949,173	$ 39,296	$ 39,493	$ 39,690	$ 39,889	$ 40,088	$ 40,289	$ 40,490	$ 40,692	$ 40,896	$ 41,100	$ 41,306	$ 41,512	$ 41,720	$ 8,385,707
Advanced Meter Deployment Costs (Scenario 1) - Water	$ 9,334,605	$ 9,427,951	$ 93,813	$ 94,282	$ 94,753	$ 95,227	$ 95,703	$ 96,182	$ 96,663	$ 97,146	$ 97,632	$ 98,120	$ 98,610	$ 99,103	$ 99,599	$ 20,019,388
Fixed Metering Network Installation Costs (Scenario 1)	$ 445,900	$ 445,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 891,800
Fiber Integration & Upgrade for Backhaul (Scenario 1)	$ 87,500	$ 87,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175,000
Back Office/Data Management Costs (Scenario 1)	$ 750,000	$ 557,500	$ 315,188	$ 323,067	$ 331,144	$ 339,422	$ 347,908	$ 356,606	$ 365,521	$ 374,659	$ 384,025	$ 393,626	$ 403,467	$ 413,553	$ 423,892	$ 6,079,578
PTC Program Costs (Scenario 1)	$ 180,300	$ 182,700	$ 185,738	$ 188,513	$ 191,329	$ 194,184	$ 197,082	$ 200,021	$ 203,304	$ 206,332	$ 83,105	$ 85,025	$ 86,993	$ 89,011	$ 91,078	$ 2,364,716
TOU/TVR Implementation Costs	$ 180,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 687,958
Prepay Implementation Costs	$ 130,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 637,958
Total Cost	$ 16,058,480	$ 16,099,027	$ 1,737,174	$ 779,309	$ 792,485	$ 805,947	$ 819,703	$ 833,758	$ 848,422	$ 863,101	$ 761,803	$ 765,937	$ 780,410	$ 795,231	$ 810,408	$ 43,541,194
Contingency (15%)	$ 2,408,772	$ 2,414,854	$ 260,576	$ 116,896	$ 118,873	$ 120,892	$ 122,955	$ 125,064	$ 127,263	$ 129,465	$ 112,770	$ 114,891	$ 117,061	$ 119,285	$ 121,561	$ 6,531,179
Total Cost with Contingency	$ 18,467,252	$ 18,513,882	$ 1,997,750	$ 896,205	$ 911,358	$ 926,839	$ 942,658	$ 958,822	$ 975,685	$ 992,566	$ 864,574	$ 880,827	$ 897,471	$ 914,515	$ 931,969	$ 50,072,373

COLUMBIA DIRECT BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Operational Savings																
Realized Savings from Avoided Meter Reading (Scenario 1)	$ 445,350	$ 912,968	$ 935,792	$ 959,186	$ 983,166	$ 1,007,745	$ 1,032,939	$ 1,058,762	$ 1,085,231	$ 1,112,362	$ 1,140,171	$ 1,168,676	$ 1,197,892	$ 1,227,840	$ 1,258,536	$ 15,526,617
Revenue from Increased Electric Meter Accuracy (Scenario 1)	$ 57,456	$ 118,373	$ 121,939	$ 125,612	$ 129,396	$ 133,294	$ 137,310	$ 141,446	$ 145,707	$ 150,097	$ 154,619	$ 159,276	$ 164,075	$ 169,017	$ 174,109	$ 2,081,727
Revenue from Increased Water Meter Accuracy (Scenario 1)	$ 18,362	$ 37,830	$ 38,970	$ 40,143	$ 41,353	$ 42,599	$ 43,882	$ 45,204	$ 46,566	$ 47,968	$ 49,413	$ 50,902	$ 52,435	$ 54,015	$ 55,642	$ 665,283
Savings from Reduced Meter Reading Safety Risk (Scenario 1)	$ 2,400	$ 4,920	$ 5,043	$ 5,169	$ 5,298	$ 5,431	$ 5,567	$ 5,706	$ 5,848	$ 5,995	$ 6,144	$ 6,298	$ 6,455	$ 6,617	$ 6,782	$ 83,673
Savings from Reduction in Outage Related Calls (Scenario 1)	$ 368	$ 880	$ 1,289	$ 1,322	$ 1,355	$ 1,388	$ 1,423	$ 1,459	$ 1,495	$ 1,533	$ 1,571	$ 1,610	$ 1,650	$ 1,692	$ 1,734	$ 20,769
Savings from Reduced Outage Truck Rolls (Scenario 1)	$ 14,800	$ 32,236	$ 38,873	$ 39,845	$ 40,841	$ 41,862	$ 42,909	$ 43,981	$ 45,081	$ 46,208	$ 47,363	$ 48,547	$ 49,761	$ 51,005	$ 52,280	$ 635,593
Savings from Reduced Connect/Disconnect Truck Rolls (Scenario 1)	$ 70,653	$ 153,890	$ 185,574	$ 190,213	$ 194,968	$ 199,843	$ 204,839	$ 209,960	$ 215,209	$ 220,589	$ 226,104	$ 231,756	$ 237,550	$ 243,489	$ 249,576	$ 3,034,212
Savings from Reduced Transformer Oversizing (Scenario 1)	$ 16,000	$ 34,850	$ 42,025	$ 43,076	$ 44,153	$ 45,256	$ 46,388	$ 47,547	$ 48,736	$ 49,955	$ 51,203	$ 52,483	$ 53,796	$ 55,140	$ 56,519	$ 687,127
Savings from Reduced Debt Write-offs (Scenario 1)	$ 56,270	$ 122,563	$ 147,796	$ 151,491	$ 155,279	$ 159,161	$ 163,140	$ 167,218	$ 171,399	$ 175,684	$ 180,076	$ 184,577	$ 189,192	$ 193,922	$ 198,770	$ 2,416,536
Energy Savings																
Realized Savings from Reduced Energy Losses (Scenario 1)	$ 139,172	$ 326,358	$ 468,557	$ 470,899	$ 473,254	$ 475,620	$ 477,998	$ 480,388	$ 482,790	$ 485,204	$ 487,630	$ 490,068	$ 492,519	$ 494,981	$ 497,456	$ 6,742,895
Realized Savings from Reduced Water Losses (Scenario 1)	$ 180,455	$ 362,715	$ 364,529	$ 366,352	$ 368,183	$ 370,024	$ 371,874	$ 373,734	$ 375,602	$ 377,480	$ 379,368	$ 381,265	$ 383,171	$ 385,087	$ 387,012	$ 5,426,853
Realized Savings from Reduced Theft Losses (Scenario 1)	$ 10,438	$ 24,477	$ 35,142	$ 35,317	$ 35,494	$ 35,672	$ 35,850	$ 36,029	$ 36,209	$ 36,390	$ 36,572	$ 36,755	$ 36,939	$ 37,124	$ 37,309	$ 505,717
Wholesale Energy Savings from Volt/VAR Optimization (Scenario 1)	$ 105,647	$ 225,621	$ 266,764	$ 268,098	$ 269,439	$ 270,786	$ 272,140	$ 273,500	$ 274,868	$ 276,242	$ 277,623	$ 279,012	$ 280,407	$ 281,809	$ 283,218	$ 3,905,173
Revenue Loss from Volt/VAR Optimization (Scenario 1)	$ (234,458)	$ (505,697)	$ (603,861)	$ (612,919)	$ (622,113)	$ (631,445)	$ (640,916)	$ (650,530)	$ (660,288)	$ (670,192)	$ (680,245)	$ (690,449)	$ (700,805)	$ (711,318)	$ (721,987)	$ (9,337,222)
Wholesale Energy Savings from Residential PCTs (Scenario 1)	$ 1,883	$ 7,750	$ 17,620	$ 23,851	$ 30,264	$ 36,864	$ 43,653	$ 50,635	$ 57,830	$ 65,227	$ 66,211	$ 67,208	$ 68,219	$ 69,243	$ 70,280	$ 676,736
Revenue Loss from Residential PCTs (Scenario 1)	$ (3,806)	$ (15,824)	$ (36,333)	$ (49,670)	$ (63,654)	$ (78,305)	$ (93,649)	$ (109,710)	$ (126,546)	$ (144,152)	$ (147,783)	$ (151,501)	$ (155,309)	$ (159,209)	$ (163,203)	$ (1,498,656)
Wholesale Energy Savings from Residential TOU (Scenario 1)	$ 3,803	$ 7,712	$ 11,747	$ 15,901	$ 20,176	$ 24,576	$ 29,102	$ 33,757	$ 38,553	$ 43,485	$ 44,141	$ 44,805	$ 45,479	$ 46,162	$ 46,854	$ 456,251
Revenue Loss from Residential TOU (Scenario 1)	$ (7,689)	$ (15,745)	$ (24,222)	$ (33,114)	$ (42,436)	$ (52,204)	$ (62,433)	$ (73,140)	$ (84,364)	$ (96,101)	$ (98,522)	$ (101,001)	$ (103,539)	$ (106,139)	$ (108,802)	$ (1,009,451)
Wholesale Energy Savings from Prepay (Scenario 1)	$ 13,312	$ 26,991	$ 41,113	$ 55,652	$ 70,616	$ 86,015	$ 101,856	$ 118,149	$ 134,937	$ 152,196	$ 154,492	$ 156,819	$ 159,177	$ 161,566	$ 163,987	$ 1,596,878
Revenue Loss from Residential Prepay (Scenario 1)	$ (26,911)	$ (55,109)	$ (84,776)	$ (115,898)	$ (148,525)	$ (182,713)	$ (218,515)	$ (255,990)	$ (295,275)	$ (336,355)	$ (344,827)	$ (353,503)	$ (362,388)	$ (371,488)	$ (380,807)	$ (3,533,080)
Peak Energy Savings																
Peak Energy Savings from Residential PCTs (Scenario 1)	$ 1,353	$ 2,730	$ 4,138	$ 5,574	$ 7,038	$ 8,529	$ 10,050	$ 11,600	$ 13,182	$ 14,794	$ 14,942	$ 15,092	$ 15,243	$ 15,395	$ 15,548	$ 155,208
Deferred Generation Savings from Residential PCTs (Scenario 1)	$ 2,406	$ 9,660	$ 21,852	$ 39,048	$ 61,320	$ 75,345	$ 91,427	$ 108,673	$ 127,185	$ 146,999	$ 152,906	$ 159,047	$ 165,430	$ 172,066	$ 178,963	$ 1,512,326
Peak Energy Savings from Residential TOU (Scenario 1)	$ 3,128	$ 6,310	$ 9,564	$ 12,882	$ 16,264	$ 19,713	$ 23,227	$ 26,808	$ 30,465	$ 34,191	$ 34,534	$ 34,879	$ 35,228	$ 35,579	$ 35,932	$ 358,703
Deferred Generation Savings from Residential TOU (Scenario 1)	$ 1,805	$ 7,245	$ 16,389	$ 29,286	$ 45,990	$ 56,508	$ 68,570	$ 81,505	$ 95,388	$ 110,249	$ 114,680	$ 119,285	$ 124,073	$ 129,049	$ 134,222	$ 1,134,245
Peak Energy Reduction from Volt/VAR Optimization (Scenario 1)	$ 7,695	$ 16,516	$ 19,625	$ 19,822	$ 20,021	$ 20,221	$ 20,424	$ 20,629	$ 20,836	$ 21,044	$ 21,255	$ 21,469	$ 21,684	$ 21,901	$ 22,121	$ 295,262
Deferred Generation Savings from Residential Volt/VAR Opt. (Scenario 1)	$ 13,680	$ 58,431	$ 103,629	$ 138,862	$ 174,446	$ 178,624	$ 185,800	$ 193,265	$ 201,029	$ 209,106	$ 217,507	$ 226,245	$ 235,334	$ 244,789	$ 254,623	$ 2,635,370
Total Columbia Direct Benefits	$ 893,570	$ 1,908,653	$ 2,148,777	$ 2,226,001	$ 2,311,586	$ 2,350,409	$ 2,394,852	$ 2,440,585	$ 2,487,674	$ 2,536,196	$ 2,587,149	$ 2,639,622	$ 2,693,665	$ 2,749,331	$ 2,806,673	$ 35,174,746
Net Cost/Benefit (Without Customer or Community Benefits)	$ (17,573,682)	$ (16,605,228)	$ 151,027	$ 1,329,796	$ 1,400,228	$ 1,423,570	$ 1,452,194	$ 1,481,763	$ 1,511,989	$ 1,543,630	$ 1,722,575	$ 1,758,795	$ 1,796,194	$ 1,834,816	$ 1,874,704	$ (14,897,628)
Cum. Net Cost/Benefit (Without Customer or Community Benefits)	$ (17,573,682)	$ (34,178,910)	$ (34,027,883)	$ (32,698,087)	$ (31,297,859)	$ (29,874,289)	$ (28,422,095)	$ (26,940,333)	$ (25,428,343)	$ (23,884,713)	$ (22,162,138)	$ (20,403,343)	$ (18,607,149)	$ (16,772,333)	$ (14,897,628)	

year$	2013
discount rate	5.0%

IRR ($)		**-6.3%**
NPV (2013$)	**$**	**(20,574,048)**
Simple Payback Period		**Over 15 yrs**

COLUMBIA CUSTOMER BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Energy Savings																
Customer Savings from Volt/VAR Optimization (Scenario 1)	$ 234,458	$ 505,697	$ 603,861	$ 612,919	$ 622,113	$ 631,445	$ 640,916	$ 650,530	$ 660,288	$ 670,192	$ 680,245	$ 690,449	$ 700,805	$ 711,318	$ 721,987	$ 9,337,222
Customer Savings from Residential PCTs (Scenario 1)	$ 3,806	$ 15,824	$ 36,333	$ 49,670	$ 63,654	$ 78,305	$ 93,649	$ 109,710	$ 126,546	$ 144,152	$ 147,783	$ 151,501	$ 155,309	$ 159,209	$ 163,203	$ 1,498,656
Customer Savings from Residential TOU (Scenario 1)	$ 7,689	$ 15,745	$ 24,222	$ 33,114	$ 42,436	$ 52,204	$ 62,433	$ 73,140	$ 84,364	$ 96,101	$ 98,522	$ 101,001	$ 103,539	$ 106,139	$ 108,802	$ 1,009,451
Customer Savings from Residential Prepay (Scenario 1)	$ 26,911	$ 55,109	$ 84,776	$ 115,898	$ 148,525	$ 182,713	$ 218,515	$ 255,990	$ 295,275	$ 336,355	$ 344,827	$ 353,503	$ 362,388	$ 371,488	$ 380,807	$ 3,533,080
Total Columbia Customer Benefits	$ 272,864	$ 592,374	$ 749,192	$ 811,601	$ 876,728	$ 944,666	$ 1,015,514	$ 1,089,370	$ 1,166,474	$ 1,246,801	$ 1,271,376	$ 1,296,453	$ 1,322,042	$ 1,348,154	$ 1,374,798	$ 15,378,409
Net Cost/Benefit (Without Community Benefits)	$ (17,300,817)	$ (16,012,854)	$ 900,219	$ 2,141,397	$ 2,276,956	$ 2,368,236	$ 2,467,708	$ 2,571,133	$ 2,678,463	$ 2,790,431	$ 2,993,952	$ 3,055,248	$ 3,118,237	$ 3,182,970	$ 3,249,504	$ 480,781
Cum. Net Cost/Benefit (Without Community Benefits)	$ (17,300,817)	$ (33,313,671)	$ (32,413,452)	$ (30,272,056)	$ (27,995,100)	$ (25,626,864)	$ (23,159,156)	$ (20,588,023)	$ (17,909,560)	$ (15,119,129)	$ (12,125,178)	$ (9,069,929)	$ (5,951,693)	$ (2,768,723)	$ 480,781	

IRR ($)		**0.2%**
NPV (2013$)	**$**	**(10,185,720)**
Simple Payback Period		**14.9 yrs**

COLUMBIA COMMUNITY BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Environmental Value																
Value from Reduced AMR Emissions (Scenario 1)	$ 36	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 1,033
Value from Reduced Outage Response Emissions (Scenario 1)	$ 4	$ 9	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 157
Value from Reduced Generation Emissions (Scenario 1)	$ 21,979	$ 46,942	$ 56,010	$ 56,732	$ 57,468	$ 58,218	$ 58,982	$ 59,761	$ 60,556	$ 61,366	$ 61,441	$ 61,516	$ 61,592	$ 61,668	$ 61,745	$ 845,975
Service Value																
Enhanced Residential Service Value from Reduced Outage Time (Scenario	$ 3,581	$ 7,647	$ 9,041	$ 9,086	$ 9,131	$ 9,177	$ 9,223	$ 9,269	$ 9,315	$ 9,362	$ 9,408	$ 9,456	$ 9,503	$ 9,551	$ 9,598	$ 132,347
Enhanced Small C&I Service Value from Reduced Outage Time (Scenario 1	$ 202,074	$ 431,544	$ 510,213	$ 512,726	$ 515,332	$ 517,939	$ 520,545	$ 523,152	$ 525,758	$ 528,365	$ 530,971	$ 533,671	$ 536,370	$ 539,070	$ 541,769	$ 7,469,499
Enhanced Large C&I Service Value from Reduced Outage Time (Scenario 1	$ 380,929	$ 813,842	$ 962,599	$ 967,738	$ 972,876	$ 978,015	$ 983,153	$ 988,291	$ 993,430	$ 998,568	$ 1,003,707	$ 1,008,845	$ 1,013,984	$ 1,019,122	$ 1,024,260	$ 14,109,358
Total Community Benefits	$ 608,603	$ 1,300,055	$ 1,537,946	$ 1,546,364	$ 1,554,890	$ 1,563,430	$ 1,571,985	$ 1,580,555	$ 1,589,141	$ 1,597,743	$ 1,605,609	$ 1,613,570	$ 1,621,631	$ 1,629,493	$ 1,637,456	$ 22,558,370
Net Cost/Benefit	$ (16,692,215)	$ (14,712,799)	$ 2,438,164	$ 3,687,761	$ 3,831,846	$ 3,931,666	$ 4,039,693	$ 4,151,688	$ 4,267,604	$ 4,388,174	$ 4,599,561	$ 4,668,818	$ 4,739,767	$ 4,812,463	$ 4,886,959	$ 23,039,151
Cumulative Net Cost/Benefit	$ (16,692,215)	$ (31,405,014)	$ (28,966,849)	$ (25,279,089)	$ (21,447,243)	$ (17,515,577)	$ (13,475,884)	$ (9,324,196)	$ (5,056,592)	$ (668,418)	$ 3,931,143	$ 8,599,961	$ 13,339,729	$ 18,152,192	$ 23,039,151	

IRR ($)		**7.5%**
NPV (2013$)	**$**	**5,821,069**
Simple Payback Period		**10.1 yrs**

Nominal Case - With Demand Side Management Programs

Economic Impacts from Smart Grid Implementation and Enhanced Operations - COMPREHENSIVE APPROACH - HOSTED SOLUTION (Scenario 2)

COSTS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
DA Annual Capital Expenditures (Scenario 2)	$ 1,040,102	$ 1,386,803	$ 1,040,102	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 4,299,090
Solution as a Service Hosted AMI/MDMS (Scenario 2) - Electric	$ 3,355,632	$ 3,372,410	$ 3,389,272	$ 3,406,219	$ 3,423,250	$ 3,440,366	$ 3,457,568	$ 3,474,856	$ 3,492,230	$ 3,509,691	$ 3,527,239	$ 3,544,876	$ 3,562,600	$ 3,580,413	$ 3,598,315	$ 52,134,936
Solution as a Service Hosted AMI/MDMS (Scenario 2) - Water	$ 3,334,752	$ 3,351,426	$ 3,368,183	$ 3,385,024	$ 3,401,949	$ 3,418,959	$ 3,436,053	$ 3,453,234	$ 3,470,500	$ 3,487,852	$ 3,505,292	$ 3,522,818	$ 3,540,432	$ 3,558,134	$ 3,575,925	$ 51,810,533
Fiber Integration & Upgrade for Backhaul (Scenario 2)	$ 175,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175,000
PTC Program Costs (Scenario 2)	$ 180,300	$ 182,700	$ 185,738	$ 188,513	$ 191,329	$ 194,184	$ 197,082	$ 200,021	$ 203,304	$ 206,332	$ 83,105	$ 85,025	$ 86,993	$ 89,011	$ 91,078	$ 2,364,716
TOU/TVR Implementation Costs	$ 180,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 687,958
Prepay Implementation Costs	$ 130,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 637,958
Total Cost	$ 8,396,786	$ 8,354,839	$ 8,046,332	$ 7,113,709	$ 7,152,096	$ 7,190,734	$ 7,229,625	$ 7,268,772	$ 7,308,478	$ 7,348,147	$ 7,261,781	$ 7,300,784	$ 7,340,059	$ 7,379,609	$ 7,419,437	$ 112,110,190
Contingency (15% excluding hosted service costs)	$ 228,810	$ 240,038	$ 188,604	$ 43,524	$ 44,067	$ 44,620	$ 45,182	$ 45,753	$ 46,379	$ 46,971	$ 28,627	$ 29,059	$ 29,502	$ 29,956	$ 30,421	$ 1,121,514
Total Cost with Contingency	$ 8,624,597	$ 8,594,877	$ 8,234,936	$ 7,157,233	$ 7,196,164	$ 7,235,354	$ 7,274,806	$ 7,314,525	$ 7,354,858	$ 7,396,118	$ 7,290,409	$ 7,329,844	$ 7,369,561	$ 7,409,566	$ 7,449,858	$ 113,231,705

COLUMBIA DIRECT BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Operational Savings																
Realized Savings from Avoided Meter Reading (Scenario 2)	$ 890,700	$ 912,968	$ 935,792	$ 959,186	$ 983,166	$ 1,007,745	$ 1,032,939	$ 1,058,762	$ 1,085,231	$ 1,112,362	$ 1,140,171	$ 1,168,676	$ 1,197,892	$ 1,227,840	$ 1,258,536	$ 15,971,967
Revenue from Increased Electric Meter Accuracy (Scenario 2)	$ 114,911	$ 118,373	$ 121,939	$ 125,612	$ 129,396	$ 133,294	$ 137,310	$ 141,446	$ 145,707	$ 150,097	$ 154,619	$ 159,276	$ 164,075	$ 169,017	$ 174,109	$ 2,139,183
Revenue from Increased Water Meter Accuracy (Scenario 2)	$ 36,724	$ 37,780	$ 38,868	$ 39,987	$ 41,138	$ 42,323	$ 43,542	$ 44,796	$ 46,087	$ 47,415	$ 48,782	$ 50,188	$ 51,635	$ 53,124	$ 54,656	$ 677,043
Savings from Reduced Meter Reading Safety Risk (Scenario 2)	$ 4,800	$ 4,920	$ 5,043	$ 5,169	$ 5,298	$ 5,431	$ 5,567	$ 5,706	$ 5,848	$ 5,995	$ 6,144	$ 6,298	$ 6,455	$ 6,617	$ 6,782	$ 86,073
Savings from Reduction in Outage Related Calls (Scenario 2)	$ 368	$ 880	$ 1,289	$ 1,322	$ 1,355	$ 1,388	$ 1,423	$ 1,459	$ 1,495	$ 1,533	$ 1,571	$ 1,610	$ 1,650	$ 1,692	$ 1,734	$ 20,769
Savings from Reduced Outage Truck Rolls (Scenario 2)	$ 24,050	$ 32,236	$ 38,873	$ 39,845	$ 40,841	$ 41,862	$ 42,909	$ 43,981	$ 45,081	$ 46,208	$ 47,363	$ 48,547	$ 49,761	$ 51,005	$ 52,280	$ 644,843
Savings from Reduced Connect/Disconnect Truck Rolls (Scenario 2)	$ 114,811	$ 153,890	$ 185,574	$ 190,213	$ 194,968	$ 199,843	$ 204,839	$ 209,960	$ 215,209	$ 220,589	$ 226,104	$ 231,756	$ 237,550	$ 243,489	$ 249,576	$ 3,078,370
Savings from Reduced Transformer Oversizing (Scenario 2)	$ 26,000	$ 34,850	$ 42,025	$ 43,076	$ 44,153	$ 45,256	$ 46,388	$ 47,547	$ 48,736	$ 49,955	$ 51,203	$ 52,483	$ 53,796	$ 55,140	$ 56,519	$ 697,127
Savings from Reduced Debt Write-offs (Scenario 2)	$ 91,439	$ 122,563	$ 147,796	$ 151,491	$ 155,279	$ 159,161	$ 163,140	$ 167,218	$ 171,399	$ 175,684	$ 180,076	$ 184,577	$ 189,192	$ 193,922	$ 198,770	$ 2,451,705
Energy Savings																
Realized Savings from Reduced Energy Losses (Scenario 2)	$ 139,172	$ 326,358	$ 468,557	$ 470,899	$ 473,254	$ 475,620	$ 477,998	$ 480,388	$ 482,790	$ 485,204	$ 487,630	$ 490,068	$ 492,519	$ 494,981	$ 497,456	$ 6,742,895
Realized Savings from Reduced Water Losses (Scenario 2)	$ 360,911	$ 362,715	$ 364,529	$ 366,352	$ 368,183	$ 370,024	$ 371,874	$ 373,734	$ 375,602	$ 377,480	$ 379,368	$ 381,265	$ 383,171	$ 385,087	$ 387,012	$ 5,607,308
Realized Savings from Reduced Theft Losses (Scenario 2)	$ 10,438	$ 24,477	$ 35,142	$ 35,317	$ 35,494	$ 35,672	$ 35,850	$ 36,029	$ 36,209	$ 36,390	$ 36,572	$ 36,755	$ 36,939	$ 37,124	$ 37,309	$ 505,717
Wholesale Energy Savings from Volt/VAR Optimization (Scenario 2)	$ 171,676	$ 225,621	$ 266,764	$ 268,098	$ 269,439	$ 270,786	$ 272,140	$ 273,500	$ 274,868	$ 276,242	$ 277,623	$ 279,012	$ 280,407	$ 281,809	$ 283,218	$ 3,971,202
Revenue Loss from Volt/VAR Optimization (Scenario 2)	$ (380,994)	$ (505,697)	$ (603,861)	$ (612,919)	$ (622,113)	$ (631,445)	$ (640,916)	$ (650,530)	$ (660,288)	$ (670,192)	$ (680,245)	$ (690,449)	$ (700,805)	$ (711,318)	$ (721,987)	$ (9,483,759)
Wholesale Energy Savings from Residential PCTs (Scenario 2)	$ 1,883	$ 7,750	$ 17,620	$ 23,851	$ 30,264	$ 36,864	$ 43,653	$ 50,635	$ 57,830	$ 65,227	$ 66,211	$ 67,208	$ 68,219	$ 69,243	$ 70,280	$ 676,736
Revenue Loss from Residential PCTs (Scenario 2)	$ (3,806)	$ (15,824)	$ (36,333)	$ (49,670)	$ (63,654)	$ (78,305)	$ (93,649)	$ (109,710)	$ (126,546)	$ (144,152)	$ (147,783)	$ (151,501)	$ (155,309)	$ (159,209)	$ (163,203)	$ (1,498,656)
Wholesale Energy Savings from Residential TOU (Scenario 2)	$ 3,803	$ 7,712	$ 11,747	$ 15,901	$ 20,176	$ 24,576	$ 29,102	$ 33,757	$ 38,553	$ 43,485	$ 44,141	$ 44,805	$ 45,479	$ 46,162	$ 46,854	$ 456,251
Revenue Loss from Residential TOU (Scenario 2)	$ (7,689)	$ (15,745)	$ (24,222)	$ (33,114)	$ (42,436)	$ (52,204)	$ (62,433)	$ (73,140)	$ (84,364)	$ (96,101)	$ (98,522)	$ (101,001)	$ (103,539)	$ (106,139)	$ (108,802)	$ (1,009,451)
Wholesale Energy Savings from Prepay (Scenario 2)	$ 13,312	$ 26,991	$ 41,113	$ 55,652	$ 70,616	$ 86,015	$ 101,856	$ 118,149	$ 134,937	$ 152,196	$ 154,492	$ 156,819	$ 159,177	$ 161,566	$ 163,987	$ 1,596,878
Revenue Loss from Residential Prepay (Scenario 2)	$ (26,911)	$ (55,109)	$ (84,776)	$ (115,898)	$ (148,525)	$ (182,713)	$ (218,515)	$ (255,990)	$ (295,275)	$ (336,355)	$ (344,827)	$ (353,503)	$ (362,388)	$ (371,488)	$ (380,807)	$ (3,533,080)
Peak Energy Savings																
Peak Energy Savings from Residential PCTs (Scenario 2)	$ 1,353	$ 2,730	$ 4,138	$ 5,574	$ 7,038	$ 8,529	$ 10,050	$ 11,600	$ 13,182	$ 14,794	$ 14,942	$ 15,092	$ 15,243	$ 15,395	$ 15,548	$ 155,208
Deferred Generation Savings from Residential PCTs (Scenario 2)	$ 2,406	$ 9,660	$ 21,852	$ 39,048	$ 61,320	$ 75,345	$ 91,427	$ 108,673	$ 127,185	$ 146,999	$ 152,906	$ 159,047	$ 165,430	$ 172,066	$ 178,963	$ 1,512,326
Peak Energy Savings from Residential TOU (Scenario 2)	$ 3,128	$ 6,310	$ 9,564	$ 12,882	$ 16,264	$ 19,713	$ 23,227	$ 26,808	$ 30,465	$ 34,191	$ 34,534	$ 34,879	$ 35,228	$ 35,579	$ 35,932	$ 358,703
Deferred Generation Savings from Residential TOU (Scenario 2)	$ 1,805	$ 7,245	$ 16,389	$ 29,286	$ 45,990	$ 56,508	$ 68,570	$ 81,505	$ 95,388	$ 110,249	$ 114,680	$ 119,285	$ 124,073	$ 129,049	$ 134,222	$ 1,134,245
Peak Energy Reduction from Volt/VAR Optimization (Scenario 2)	$ 12,504	$ 16,516	$ 19,625	$ 19,822	$ 20,021	$ 20,221	$ 20,424	$ 20,629	$ 20,836	$ 21,044	$ 21,255	$ 21,469	$ 21,684	$ 21,901	$ 22,121	$ 300,071
Deferred Generation Savings from Residential Volt/VAR Opt. (Scenario 2)	$ 22,230	$ 58,431	$ 103,629	$ 138,862	$ 174,446	$ 178,624	$ 185,800	$ 193,265	$ 201,029	$ 209,106	$ 217,507	$ 226,245	$ 235,334	$ 244,789	$ 254,623	$ 2,643,920
Total Columbia Direct Benefits	$ 1,629,022	$ 1,908,604	$ 2,148,875	$ 2,225,844	$ 2,311,371	$ 2,350,133	$ 2,394,512	$ 2,440,177	$ 2,487,196	$ 2,535,643	$ 2,586,517	$ 2,638,908	$ 2,692,865	$ 2,748,440	$ 2,805,687	$ 35,903,595
Net Cost/Benefit (Without Customer or Community Benefits)	$ (6,995,575)	$ (6,686,273)	$ (6,086,261)	$ (4,931,389)	$ (4,884,793)	$ (4,885,220)	$ (4,880,294)	$ (4,874,348)	$ (4,867,662)	$ (4,859,475)	$ (4,703,891)	$ (4,690,936)	$ (4,676,696)	$ (4,661,126)	$ (4,644,171)	$ (77,328,110)
Cum. Net Cost/Benefit (Without Customer or Community Benefits)	$ (6,995,575)	$ (13,681,848)	$ (19,768,109)	$ (24,699,498)	$ (29,584,291)	$ (34,469,511)	$ (39,349,806)	$ (44,224,154)	$ (49,091,816)	$ (53,951,291)	$ (58,655,182)	$ (63,346,118)	$ (68,022,814)	$ (72,683,939)	$ (77,328,110)	

year$	2013
discount rate	5.0%

IRR ($)	#NUM!
NPV (2013$)	$ (67,676,315)
Simple Payback Period	Over 15 yrs

COLUMBIA CUSTOMER BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Energy Savings																
Customer Savings from Volt/VAR Optimization (Scenario 2)	$ 380,994	$ 505,697	$ 603,861	$ 612,919	$ 622,113	$ 631,445	$ 640,916	$ 650,530	$ 660,288	$ 670,192	$ 680,245	$ 690,449	$ 700,805	$ 711,318	$ 721,987	$ 9,483,759
Customer Savings from Residential PCTs (Scenario 2)	$ 3,806	$ 15,824	$ 36,333	$ 49,670	$ 63,654	$ 78,305	$ 93,649	$ 109,710	$ 126,546	$ 144,152	$ 147,783	$ 151,501	$ 155,309	$ 159,209	$ 163,203	$ 1,498,656
Customer Savings from Residential TOU (Scenario 2)	$ 7,689	$ 15,745	$ 24,222	$ 33,114	$ 42,436	$ 52,204	$ 62,433	$ 73,140	$ 84,364	$ 96,101	$ 98,522	$ 101,001	$ 103,539	$ 106,139	$ 108,802	$ 1,009,451
Customer Savings from Residential Prepay (Scenario 2)	$ 26,911	$ 55,109	$ 84,776	$ 115,898	$ 148,525	$ 182,713	$ 218,515	$ 255,990	$ 295,275	$ 336,355	$ 344,827	$ 353,503	$ 362,388	$ 371,488	$ 380,807	$ 3,533,080
Total Columbia Customer Benefits	$ 419,401	$ 592,374	$ 749,192	$ 811,601	$ 876,728	$ 944,666	$ 1,015,514	$ 1,089,370	$ 1,166,474	$ 1,246,801	$ 1,271,376	$ 1,296,453	$ 1,322,042	$ 1,348,154	$ 1,374,799	$ 15,524,945
Net Cost/Benefit (Without Community Benefits)	$ (6,576,174)	$ (6,093,899)	$ (5,337,069)	$ (4,119,789)	$ (4,008,065)	$ (3,940,554)	$ (3,864,781)	$ (3,784,978)	$ (3,701,188)	$ (3,612,674)	$ (3,432,515)	$ (3,394,482)	$ (3,354,654)	$ (3,312,971)	$ (3,269,372)	$ (61,803,164)
Cum. Net Cost/Benefit (Without Community Benefits)	$ (6,576,174)	$ (12,670,073)	$ (18,007,142)	$ (22,126,931)	$ (26,134,996)	$ (30,075,550)	$ (33,940,330)	$ (37,725,308)	$ (41,426,496)	$ (45,039,171)	$ (48,471,686)	$ (51,866,168)	$ (55,220,822)	$ (58,533,793)	$ (61,803,164)	

IRR ($)	#NUM!
NPV (2013$)	$ (46,940,451)
Simple Payback Period	Over 15 yrs

COLUMBIA COMMUNITY BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Environmental Value																
Value from Reduced AMR Emissions (Scenario 2)	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 1,069
Value from Reduced Outage Response Emissions (Scenario 2)	$ 7	$ 9	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 159
Value from Reduced Generation Emissions (Scenario 2)	$ 35,462	$ 46,942	$ 56,010	$ 56,732	$ 57,468	$ 58,218	$ 58,982	$ 59,761	$ 60,556	$ 61,366	$ 61,441	$ 61,516	$ 61,592	$ 61,668	$ 61,745	$ 859,458
Service Value																
Enhanced Residential Service Value from Reduced Outage Time (Scenario :	$ 5,818	$ 7,647	$ 9,041	$ 9,086	$ 9,131	$ 9,177	$ 9,223	$ 9,269	$ 9,315	$ 9,362	$ 9,408	$ 9,456	$ 9,503	$ 9,551	$ 9,598	$ 134,585
Enhanced Small C&I Service Value from Reduced Outage Time (Scenario 2	$ 328,371	$ 431,544	$ 510,213	$ 512,726	$ 515,332	$ 517,939	$ 520,545	$ 523,152	$ 525,758	$ 528,365	$ 530,971	$ 533,671	$ 536,370	$ 539,070	$ 541,769	$ 7,595,796
Enhanced Large C&I Service Value from Reduced Outage Time (Scenario 2	$ 619,010	$ 813,842	$ 962,599	$ 967,738	$ 972,876	$ 978,015	$ 983,153	$ 988,291	$ 993,430	$ 998,568	$ 1,003,707	$ 1,008,845	$ 1,013,984	$ 1,019,122	$ 1,024,260	$ 14,347,439
Total Community Benefits	$ 988,739	$ 1,300,055	$ 1,537,946	$ 1,546,364	$ 1,554,890	$ 1,563,430	$ 1,571,985	$ 1,580,555	$ 1,589,141	$ 1,597,743	$ 1,605,609	$ 1,613,570	$ 1,621,531	$ 1,629,493	$ 1,637,456	$ 22,938,506
Net Cost/Benefit	$ (5,587,436)	$ (4,793,844)	$ (3,799,124)	$ (2,573,425)	$ (2,453,175)	$ (2,377,124)	$ (2,292,796)	$ (2,204,423)	$ (2,112,047)	$ (2,014,931)	$ (1,826,906)	$ (1,780,913)	$ (1,733,123)	$ (1,683,478)	$ (1,631,916)	$ (38,864,659)
Cumulative Net Cost/Benefit	$ (5,587,436)	$ (10,381,280)	$ (14,180,403)	$ (16,753,828)	$ (19,207,003)	$ (21,584,127)	$ (23,876,922)	$ (26,081,345)	$ (28,193,392)	$ (30,208,323)	$ (32,035,229)	$ (33,816,141)	$ (35,549,265)	$ (37,232,743)	$ (38,864,659)	

IRR ($)	#NUM!
NPV (2013$)	$ (30,553,537)
Simple Payback Period	Over 15 yrs

Nominal Case - With Demand Side Management Programs

Economic Impacts from Smart Grid Implementation and Enhanced Operations - ENHANCED AMR APPROACH (Scenario 3)

COSTS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
DA Annual Capital Expenditures (Scenario 3)	$ 1,040,102	$ 1,386,803	$ 1,040,102	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 4,299,090
Advanced Meter Deployment Costs (Scenario 3) - Electric	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Advanced Meter Deployment Costs (Scenario 3) - Water	$ 4,018,250	$ 20,091	$ 20,192	$ 20,293	$ 20,394	$ 20,496	$ 20,599	$ 20,702	$ 20,805	$ 20,909	$ 21,014	$ 21,119	$ 21,224	$ 21,330	$ 21,437	$ 4,308,854
Fixed Metering Network Installation Costs (Scenario 3)	$ 445,900	$ 445,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 891,800
Fiber Integration & Upgrade for Backhaul (Scenario 3)	$ 175,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175,000
Back Office/Data Management Costs (Scenario 3)	$ 1,000,000	$ 307,500	$ 315,188	$ 323,067	$ 331,144	$ 339,422	$ 347,908	$ 356,606	$ 365,521	$ 374,659	$ 384,025	$ 393,626	$ 403,467	$ 413,553	$ 423,892	$ 6,079,578
PTC Program Costs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOU/TVR Implementation Costs	$ 180,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 687,958
Prepay Implementation Costs	$ 130,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 637,958
Total Cost	$ 6,989,252	$ 2,221,794	$ 1,438,519	$ 477,313	$ 487,107	$ 497,143	$ 507,428	$ 517,969	$ 528,770	$ 539,840	$ 551,184	$ 562,810	$ 574,724	$ 586,935	$ 599,448	$ 17,080,238
Contingency (15%)	$ 1,048,388	$ 333,269	$ 215,778	$ 71,597	$ 73,066	$ 74,571	$ 76,114	$ 77,695	$ 79,316	$ 80,976	$ 82,678	$ 84,422	$ 86,209	$ 88,040	$ 89,917	$ 2,562,036
Total Cost with Contingency	$ 8,037,640	$ 2,555,064	$ 1,654,297	$ 548,910	$ 560,173	$ 571,715	$ 583,543	$ 595,664	$ 608,086	$ 620,816	$ 633,862	$ 647,232	$ 660,933	$ 674,975	$ 689,365	$ 19,642,274

COLUMBIA DIRECT BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Operational Savings																
Realized Savings from Avoided Meter Reading (Scenario 3)	$ 445,350	$ 912,968	$ 935,792	$ 959,186	$ 983,166	$ 1,007,745	$ 1,032,939	$ 1,058,762	$ 1,085,231	$ 1,112,362	$ 1,140,171	$ 1,168,676	$ 1,197,892	$ 1,227,840	$ 1,258,536	$ 15,526,617
Revenue from Increased Electric Meter Accuracy (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue from Increased Water Meter Accuracy (Scenario 3)	$ 36,724	$ 37,738	$ 38,781	$ 39,852	$ 40,954	$ 42,086	$ 43,250	$ 44,446	$ 45,676	$ 46,940	$ 48,239	$ 49,575	$ 50,948	$ 52,359	$ 53,810	$ 671,377
Savings from Reduced Meter Reading Safety Risk (Scenario 3)	$ 4,800	$ 4,920	$ 5,043	$ 5,169	$ 5,298	$ 5,431	$ 5,567	$ 5,706	$ 5,848	$ 5,995	$ 6,144	$ 6,298	$ 6,455	$ 6,617	$ 6,782	$ 86,073
Savings from Reduction in Outage Related Calls (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Savings from Reduced Outage Truck Rolls (Scenario 3)	$ 24,050	$ 32,236	$ 38,873	$ 39,845	$ 40,841	$ 41,862	$ 42,909	$ 43,981	$ 45,081	$ 46,208	$ 47,363	$ 48,547	$ 49,761	$ 51,005	$ 52,280	$ 644,843
Savings from Reduced Connect/Disconnect Truck Rolls (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Savings from Reduced Transformer Oversizing (Scenario 3)	$ 26,000	$ 34,850	$ 42,025	$ 43,076	$ 44,153	$ 45,256	$ 46,388	$ 47,547	$ 48,736	$ 49,955	$ 51,203	$ 52,483	$ 53,796	$ 55,140	$ 56,519	$ 697,127
Savings from Reduced Debt Write-offs (Scenario 3)	$ 91,439	$ 122,563	$ 147,796	$ 151,491	$ 155,279	$ 159,161	$ 163,140	$ 167,218	$ 171,399	$ 175,684	$ 180,076	$ 184,577	$ 189,192	$ 193,922	$ 198,770	$ 2,451,705
Energy Savings																
Realized Savings from Reduced Energy Losses (Scenario 3)	$ 139,172	$ 326,358	$ 468,557	$ 470,899	$ 473,254	$ 475,620	$ 477,998	$ 480,388	$ 482,790	$ 485,204	$ 487,630	$ 490,068	$ 492,519	$ 494,981	$ 497,456	$ 6,742,895
Realized Savings from Reduced Water Losses (Scenario 3)	$ 360,911	$ 362,715	$ 364,529	$ 366,352	$ 368,183	$ 370,024	$ 371,874	$ 373,734	$ 375,602	$ 377,480	$ 379,368	$ 381,265	$ 383,171	$ 385,087	$ 387,012	$ 5,607,308
Realized Savings from Reduced Theft Losses (Scenario 3)	$ 10,438	$ 24,477	$ 35,142	$ 35,317	$ 35,494	$ 35,672	$ 35,850	$ 36,029	$ 36,209	$ 36,390	$ 36,572	$ 36,755	$ 36,939	$ 37,124	$ 37,309	$ 505,717
Wholesale Energy Savings from Volt/VAR Optimization (Scenario 3)	$ 171,676	$ 225,621	$ 266,764	$ 268,098	$ 269,439	$ 270,786	$ 272,140	$ 273,500	$ 274,868	$ 276,242	$ 277,623	$ 279,012	$ 280,407	$ 281,809	$ 283,218	$ 3,971,202
Revenue Loss from Volt/VAR Optimization (Scenario 3)	$ (380,994)	$ (505,697)	$ (603,861)	$ (612,919)	$ (622,113)	$ (631,445)	$ (640,916)	$ (650,530)	$ (660,288)	$ (670,192)	$ (680,245)	$ (690,449)	$ (700,805)	$ (711,318)	$ (721,987)	$ (9,483,759)
Wholesale Energy Savings from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Residential TOU (Scenario 3)	$ 3,803	$ 7,712	$ 11,747	$ 15,901	$ 20,176	$ 24,576	$ 29,102	$ 33,757	$ 38,553	$ 43,485	$ 44,141	$ 44,805	$ 45,479	$ 46,162	$ 46,854	$ 456,251
Revenue Loss from Residential TOU (Scenario 3)	$ (7,689)	$ (15,745)	$ (24,222)	$ (33,114)	$ (42,436)	$ (52,204)	$ (62,433)	$ (73,140)	$ (84,364)	$ (96,101)	$ (98,522)	$ (101,001)	$ (103,539)	$ (106,139)	$ (108,802)	$ (1,009,451)
Wholesale Energy Savings from Prepay (Scenario 3)	$ 13,312	$ 26,991	$ 41,113	$ 55,652	$ 70,616	$ 86,015	$ 101,856	$ 118,149	$ 134,937	$ 152,196	$ 154,492	$ 156,819	$ 159,177	$ 161,566	$ 163,987	$ 1,596,878
Revenue Loss from Residential Prepay (Scenario 3)	$ (26,911)	$ (55,109)	$ (84,776)	$ (115,898)	$ (148,525)	$ (182,713)	$ (218,515)	$ (255,990)	$ (295,275)	$ (336,355)	$ (344,827)	$ (353,503)	$ (362,388)	$ (371,488)	$ (380,807)	$ (3,533,080)
Peak Energy Savings																
Peak Energy Savings from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peak Energy Savings from Residential TOU (Scenario 3)	$ 3,128	$ 6,310	$ 9,564	$ 12,882	$ 16,264	$ 19,713	$ 23,227	$ 26,808	$ 30,465	$ 34,191	$ 34,534	$ 34,879	$ 35,228	$ 35,579	$ 35,932	$ 358,703
Deferred Generation Savings from Residential TOU (Scenario 3)	$ 1,805	$ 7,245	$ 16,389	$ 29,286	$ 45,990	$ 56,508	$ 68,570	$ 81,505	$ 95,388	$ 110,249	$ 114,680	$ 119,285	$ 124,073	$ 129,049	$ 134,222	$ 1,134,245
Peak Energy Reduction from Volt/VAR Optimization (Scenario 3)	$ 12,504	$ 16,516	$ 19,625	$ 19,822	$ 20,021	$ 20,221	$ 20,424	$ 20,629	$ 20,836	$ 21,044	$ 21,255	$ 21,469	$ 21,684	$ 21,901	$ 22,121	$ 300,071
Deferred Generation Savings from Residential Volt/VAR Opt. (Scenario 3)	$ 22,230	$ 58,431	$ 103,629	$ 138,862	$ 174,446	$ 178,624	$ 185,800	$ 193,265	$ 201,029	$ 209,106	$ 217,507	$ 226,245	$ 235,334	$ 244,789	$ 254,623	$ 2,643,920
Total Columbia Direct Benefits	$ 951,746	$ 1,631,101	$ 1,832,509	$ 1,889,760	$ 1,950,500	$ 1,972,939	$ 1,999,168	$ 2,025,765	$ 2,052,723	$ 2,080,082	$ 2,117,405	$ 2,155,806	$ 2,195,320	$ 2,235,984	$ 2,277,834	$ 29,368,642
Net Cost/Benefit (Without Customer or Community Benefits)	$ (7,085,894)	$ (923,963)	$ 178,212	$ 1,340,850	$ 1,390,327	$ 1,401,224	$ 1,415,626	$ 1,430,101	$ 1,444,637	$ 1,459,266	$ 1,483,543	$ 1,508,575	$ 1,534,387	$ 1,561,009	$ 1,588,469	$ 9,726,368
Cum. Net Cost/Benefit (Without Customer or Community Benefits)	$ (7,085,894)	$ (8,009,857)	$ (7,831,646)	$ (6,490,796)	$ (5,100,469)	$ (3,699,244)	$ (2,283,619)	$ (853,518)	$ 591,119	$ 2,050,385	$ 3,533,929	$ 5,042,503	$ 6,576,890	$ 8,137,899	$ 9,726,368	

year$	2013
discount rate	5.0%

IRR ($)	10.6%
NPV (2013$)	$ 3,864,258
Simple Payback Period	8.6 yrs

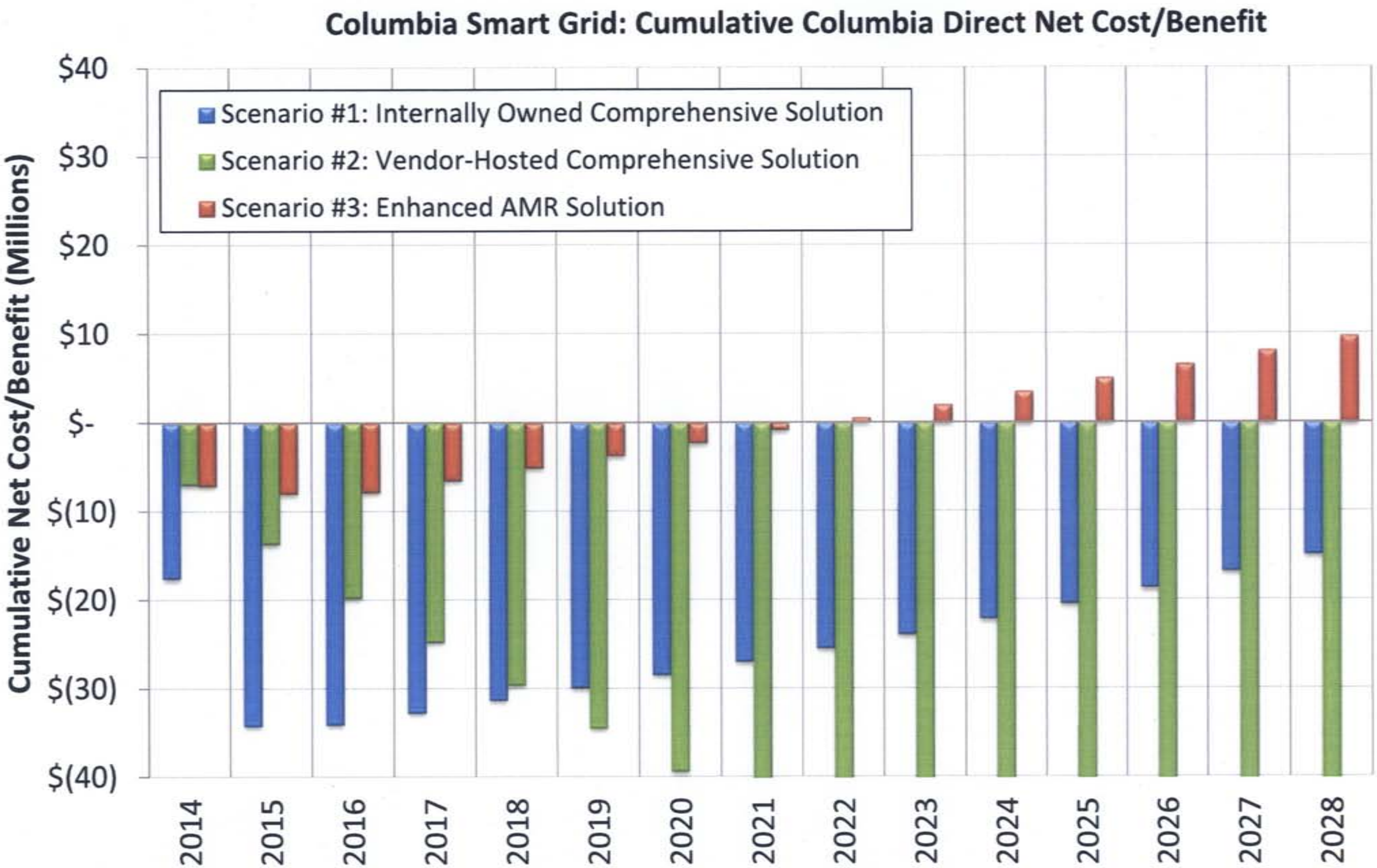
COLUMBIA CUSTOMER BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Energy Savings																
Customer Savings from Volt/VAR Optimization (Scenario 3)	$ 380,994	$ 505,697	$ 603,861	$ 612,919	$ 622,113	$ 631,445	$ 640,916	$ 650,530	$ 660,288	$ 670,192	$ 680,245	$ 690,449	$ 700,805	$ 711,318	$ 721,987	$ 9,483,759
Customer Savings from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential TOU (Scenario 3)	$ 7,689	$ 15,745	$ 24,222	$ 33,114	$ 42,436	$ 52,204	$ 62,433	$ 73,140	$ 84,364	$ 96,101	$ 98,522	$ 101,001	$ 103,539	$ 106,139	$ 108,802	$ 1,009,451
Customer Savings from Residential Prepay (Scenario 3)	$ 26,911	$ 55,109	$ 84,776	$ 115,898	$ 148,525	$ 182,713	$ 218,515	$ 255,990	$ 295,275	$ 336,355	$ 344,827	$ 353,503	$ 362,388	$ 371,488	$ 380,807	$ 3,533,080
Total Columbia Customer Benefits	$ 415,594	$ 576,550	$ 712,859	$ 761,930	$ 813,074	$ 866,361	$ 921,864	$ 979,660	$ 1,039,927	$ 1,102,649	$ 1,123,593	$ 1,144,952	$ 1,166,733	$ 1,188,945	$ 1,211,596	$ 14,026,290
Net Cost/Benefit (Without Community Benefits)	$ (6,670,300)	$ (347,412)	$ 891,071	$ 2,102,780	$ 2,203,401	$ 2,267,585	$ 2,337,490	$ 2,409,761	$ 2,484,565	$ 2,561,914	$ 2,607,137	$ 2,653,527	$ 2,701,120	$ 2,749,954	$ 2,800,066	$ 23,752,658
Cum. Net Cost/Benefit (Without Community Benefits)	$ (6,670,300)	$ (7,017,712)	$ (6,126,641)	$ (4,023,861)	$ (1,820,460)	$ 447,125	$ 2,784,615	$ 5,194,376	$ 7,678,940	$ 10,240,855	$ 12,847,992	$ 15,501,519	$ 18,202,639	$ 20,952,593	$ 23,752,658	

IRR ($)	22.6%
NPV (2013$)	$ 13,531,588
Simple Payback Period	5.8 yrs

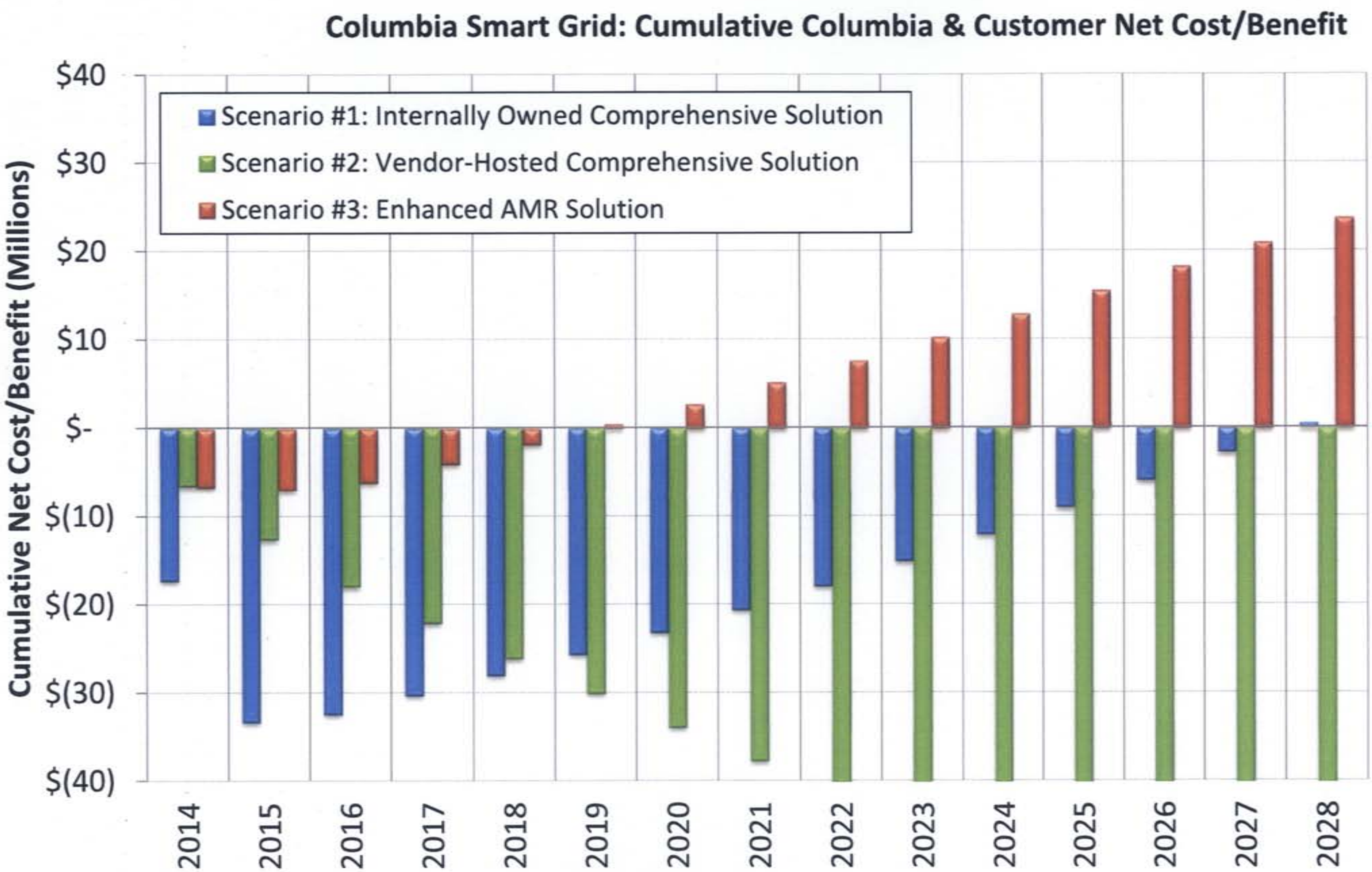
COLUMBIA COMMUNITY BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Environmental Value																
Value from Reduced AMR Emissions (Scenario 3)	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 1,069
Value from Reduced Outage Response Emissions (Scenario 3)	$ 3	$ 8	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 154
Value from Reduced Generation Emissions (Scenario 3)	$ 35,327	$ 46,390	$ 54,762	$ 55,051	$ 55,345	$ 55,645	$ 55,951	$ 56,263	$ 56,581	$ 56,905	$ 56,935	$ 56,965	$ 56,995	$ 57,026	$ 57,056	$ 813,196
Service Value																
Enhanced Residential Service Value from Reduced Outage Time (Scenario 3	$ 5,818	$ 7,647	$ 9,041	$ 9,086	$ 9,131	$ 9,177	$ 9,223	$ 9,269	$ 9,315	$ 9,362	$ 9,408	$ 9,456	$ 9,503	$ 9,551	$ 9,598	$ 134,585
Enhanced Small C&I Service Value from Reduced Outage Time (Scenario 3	$ 328,371	$ 431,544	$ 510,213	$ 512,726	$ 515,332	$ 517,939	$ 520,545	$ 523,152	$ 525,758	$ 528,365	$ 530,971	$ 533,671	$ 536,370	$ 539,070	$ 541,769	$ 7,595,796
Enhanced Large C&I Service Value from Reduced Outage Time (Scenario 3	$ 619,010	$ 813,842	$ 962,599	$ 967,738	$ 972,876	$ 978,015	$ 983,153	$ 988,291	$ 993,430	$ 998,568	$ 1,003,707	$ 1,008,845	$ 1,013,984	$ 1,019,122	$ 1,024,260	$ 14,347,439
Total Community Benefits	$ 988,600	$ 1,299,502	$ 1,536,697	$ 1,544,683	$ 1,552,768	$ 1,560,858	$ 1,568,954	$ 1,577,057	$ 1,585,166	$ 1,593,281	$ 1,601,103	$ 1,609,018	$ 1,616,934	$ 1,624,850	$ 1,632,767	$ 22,892,238
Net Cost/Benefit	$ (5,681,700)	$ 952,089	$ 2,427,768	$ 3,647,463	$ 3,756,168	$ 3,828,443	$ 3,906,444	$ 3,986,818	$ 4,069,731	$ 4,155,196	$ 4,208,240	$ 4,262,545	$ 4,318,054	$ 4,374,804	$ 4,432,832	$ 46,644,896
Cumulative Net Cost/Benefit	$ (5,681,700)	$ (4,729,611)	$ (2,301,843)	$ 1,345,621	$ 5,101,789	$ 8,930,232	$ 12,836,677	$ 16,823,494	$ 20,893,225	$ 25,048,421	$ 29,256,661	$ 33,519,206	$ 37,837,260	$ 42,212,064	$ 46,644,896	

IRR ($)	46.8%
NPV (2013$)	$ 29,888,359
Simple Payback Period	3.6 yrs

Nominal Case - With Demand Side Management Programs



Nominal Case - With Demand Side Management Programs



Nominal Case - Without Demand Side Management Programs

Economic Impacts from Smart Grid Implementation and Enhanced Operations - COMPREHENSIVE APPROACH - INTERNALLY DEPLOYED/OPERATED (Scenario 1)

COSTS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
DA Annual Capital Expenditures (Scenario 1)	$ 1,040,102	$ 1,386,803	$ 1,040,102	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 4,299,090
Advanced Meter Deployment Costs (Scenario 1) - Electric	$ 3,910,073	$ 3,949,173	$ 39,296	$ 39,493	$ 39,690	$ 39,889	$ 40,088	$ 40,289	$ 40,490	$ 40,692	$ 40,896	$ 41,100	$ 41,306	$ 41,512	$ 41,720	$ 8,385,707
Advanced Meter Deployment Costs (Scenario 1) - Water	$ 9,334,605	$ 9,427,951	$ 93,813	$ 94,282	$ 94,753	$ 95,227	$ 95,703	$ 96,182	$ 96,663	$ 97,146	$ 97,632	$ 98,120	$ 98,610	$ 99,103	$ 99,599	$ 20,019,368
Fixed Metering Network Installation Costs (Scenario 1)	$ 445,900	$ 445,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 891,800
Fiber Integration & Upgrade for Backhaul (Scenario 1)	$ 87,500	$ 87,500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175,000
Back Office/Data Management Costs (Scenario 1)	$ 750,000	$ 557,500	$ 315,188	$ 323,067	$ 331,144	$ 339,422	$ 347,908	$ 356,606	$ 365,521	$ 374,659	$ 384,025	$ 393,626	$ 403,467	$ 413,553	$ 423,892	$ 6,079,578
PTC Program Costs (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOU/TVR Implementation Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prepay Implementation Costs	$ 130,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 637,958
Total Cost	$ 15,698,180	$ 15,885,577	$ 1,519,918	$ 558,489	$ 568,042	$ 577,821	$ 587,830	$ 598,077	$ 608,566	$ 619,303	$ 630,296	$ 641,549	$ 653,070	$ 664,865	$ 676,940	$ 40,488,521
Contingency (15%)	$ 2,354,727	$ 2,382,837	$ 227,988	$ 83,773	$ 85,206	$ 86,673	$ 88,175	$ 89,711	$ 91,285	$ 92,895	$ 94,544	$ 96,232	$ 97,960	$ 99,730	$ 101,541	$ 6,073,278
Total Cost with Contingency	$ 18,052,907	$ 18,268,414	$ 1,747,905	$ 642,262	$ 653,248	$ 664,494	$ 676,005	$ 687,788	$ 699,850	$ 712,199	$ 724,840	$ 737,781	$ 751,030	$ 764,594	$ 778,481	$ 46,561,799

COLUMBIA DIRECT BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Operational Savings																
Realized Savings from Avoided Meter Reading (Scenario 1)	$ 445,350	$ 912,968	$ 935,792	$ 959,186	$ 983,166	$ 1,007,745	$ 1,032,939	$ 1,058,762	$ 1,085,231	$ 1,112,362	$ 1,140,171	$ 1,168,676	$ 1,197,892	$ 1,227,840	$ 1,258,536	$ 15,526,617
Revenue from Increased Electric Meter Accuracy (Scenario 1)	$ 57,456	$ 118,373	$ 121,939	$ 125,612	$ 129,396	$ 133,294	$ 137,310	$ 141,446	$ 145,707	$ 150,097	$ 154,619	$ 159,276	$ 164,075	$ 169,017	$ 174,109	$ 2,081,727
Revenue from Increased Water Meter Accuracy (Scenario 1)	$ 18,362	$ 37,830	$ 38,970	$ 40,143	$ 41,353	$ 42,599	$ 43,882	$ 45,204	$ 46,566	$ 47,968	$ 49,413	$ 50,902	$ 52,435	$ 54,015	$ 55,642	$ 665,283
Savings from Reduced Meter Reading Safety Risk (Scenario 1)	$ 2,400	$ 4,920	$ 5,043	$ 5,169	$ 5,298	$ 5,431	$ 5,567	$ 5,706	$ 5,848	$ 5,995	$ 6,144	$ 6,298	$ 6,455	$ 6,617	$ 6,782	$ 83,673
Savings from Reduction in Outage Related Calls (Scenario 1)	$ 368	$ 880	$ 1,289	$ 1,322	$ 1,355	$ 1,388	$ 1,423	$ 1,459	$ 1,495	$ 1,533	$ 1,571	$ 1,610	$ 1,650	$ 1,692	$ 1,734	$ 20,769
Savings from Reduced Outage Truck Rolls (Scenario 1)	$ 14,800	$ 32,236	$ 38,873	$ 39,845	$ 40,841	$ 41,862	$ 42,909	$ 43,981	$ 45,081	$ 46,208	$ 47,363	$ 48,547	$ 49,761	$ 51,005	$ 52,280	$ 635,593
Savings from Reduced Connect/Disconnect Truck Rolls (Scenario 1)	$ 70,653	$ 153,890	$ 185,574	$ 190,213	$ 194,968	$ 199,843	$ 204,839	$ 209,960	$ 215,209	$ 220,589	$ 226,104	$ 231,756	$ 237,550	$ 243,489	$ 249,576	$ 3,034,212
Savings from Reduced Transformer Oversizing (Scenario 1)	$ 16,000	$ 34,850	$ 42,025	$ 43,076	$ 44,153	$ 45,256	$ 46,388	$ 47,547	$ 48,736	$ 49,955	$ 51,203	$ 52,483	$ 53,796	$ 55,140	$ 56,519	$ 687,127
Savings from Reduced Debt Write-offs (Scenario 1)	$ 56,270	$ 122,563	$ 147,796	$ 151,491	$ 155,279	$ 159,161	$ 163,140	$ 167,218	$ 171,399	$ 175,684	$ 180,076	$ 184,577	$ 189,192	$ 193,922	$ 198,770	$ 2,416,536
Energy Savings																
Realized Savings from Reduced Energy Losses (Scenario 1)	$ 139,172	$ 326,358	$ 468,557	$ 470,899	$ 473,254	$ 475,620	$ 477,998	$ 480,388	$ 482,790	$ 485,204	$ 487,630	$ 490,068	$ 492,519	$ 494,981	$ 497,456	$ 6,742,895
Realized Savings from Reduced Water Losses (Scenario 1)	$ 180,455	$ 362,715	$ 364,529	$ 366,352	$ 368,183	$ 370,024	$ 371,874	$ 373,734	$ 375,602	$ 377,480	$ 379,368	$ 381,265	$ 383,171	$ 385,087	$ 387,012	$ 5,426,853
Realized Savings from Reduced Theft Losses (Scenario 1)	$ 10,438	$ 24,477	$ 35,142	$ 35,317	$ 35,494	$ 35,672	$ 35,850	$ 36,029	$ 36,209	$ 36,390	$ 36,572	$ 36,755	$ 36,939	$ 37,124	$ 37,309	$ 505,717
Wholesale Energy Savings from Volt/VAR Optimization (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Volt/VAR Optimization (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Residential PCTs (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Residential PCTs (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Residential TOU (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Residential TOU (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Prepay (Scenario 1)	$ 13,312	$ 26,991	$ 41,113	$ 55,652	$ 70,616	$ 86,015	$ 101,856	$ 118,149	$ 134,937	$ 152,196	$ 154,492	$ 156,819	$ 159,177	$ 161,566	$ 163,987	$ 1,596,878
Revenue Loss from Residential Prepay (Scenario 1)	$ (26,911)	$ (55,109)	$ (84,776)	$ (115,898)	$ (148,525)	$ (182,713)	$ (218,515)	$ (255,990)	$ (295,275)	$ (336,355)	$ (344,827)	$ (353,503)	$ (362,388)	$ (371,488)	$ (380,807)	$ (3,533,080)
Peak Energy Savings																
Peak Energy Savings from Residential PCTs (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential PCTs (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peak Energy Savings from Residential TOU (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential TOU (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peak Energy Reduction from Volt/VAR Optimization (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential Volt/VAR Opt. (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Columbia Direct Benefits	$ 998,124	$ 2,103,943	$ 2,341,865	$ 2,368,380	$ 2,394,831	$ 2,421,197	$ 2,447,458	$ 2,473,593	$ 2,499,536	$ 2,525,306	$ 2,569,900	$ 2,615,531	$ 2,662,224	$ 2,710,006	$ 2,758,906	$ 35,890,800
Net Cost/Benefit (Without Customer or Community Benefits)	$ (17,054,783)	$ (16,164,471)	$ 593,959	$ 1,726,119	$ 1,741,583	$ 1,756,704	$ 1,771,454	$ 1,785,805	$ 1,799,686	$ 1,813,107	$ 1,845,060	$ 1,877,749	$ 1,911,194	$ 1,945,412	$ 1,980,424	$ (10,670,999)
Cum. Net Cost/Benefit (Without Customer or Community Benefits)	$ (17,054,783)	$ (33,219,254)	$ (32,625,295)	$ (30,899,176)	$ (29,157,593)	$ (27,400,889)	$ (25,629,436)	$ (23,843,631)	$ (22,043,945)	$ (20,230,838)	$ (18,385,779)	$ (16,508,029)	$ (14,596,835)	$ (12,651,423)	$ (10,670,999)	

year$	2013
discount rate	5.0%

IRR ($)	-4.6%
NPV (2013$)	$ (17,306,843)
Simple Payback Period	Over 15 yrs

COLUMBIA CUSTOMER BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Energy Savings																
Customer Savings from Volt/VAR Optimization (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential PCTs (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential TOU (Scenario 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential Prepay (Scenario 1)	$ 26,911	$ 55,109	$ 84,776	$ 115,898	$ 148,525	$ 182,713	$ 218,515	$ 255,990	$ 295,275	$ 336,355	$ 344,827	$ 353,503	$ 362,388	$ 371,488	$ 380,807	$ 3,533,080
Total Columbia Customer Benefits	$ 26,911	$ 55,109	$ 84,776	$ 115,898	$ 148,525	$ 182,713	$ 218,515	$ 255,990	$ 295,275	$ 336,355	$ 344,827	$ 353,503	$ 362,388	$ 371,488	$ 380,807	$ 3,533,080
Net Cost/Benefit (Without Community Benefits)	$ (17,027,872)	$ (16,109,362)	$ 678,736	$ 1,842,016	$ 1,890,108	$ 1,939,416	$ 1,989,969	$ 2,041,795	$ 2,094,961	$ 2,149,461	$ 2,189,887	$ 2,231,252	$ 2,273,582	$ 2,316,900	$ 2,361,232	$ (7,137,919)
Cum. Net Cost/Benefit (Without Community Benefits)	$ (17,027,872)	$ (33,137,234)	$ (32,458,498)	$ (30,616,482)	$ (28,726,374)	$ (26,786,957)	$ (24,796,988)	$ (22,756,193)	$ (20,660,233)	$ (18,510,771)	$ (16,320,885)	$ (14,089,632)	$ (11,816,051)	$ (9,499,151)	$ (7,137,919)	

IRR ($)	-2.9%
NPV (2013$)	$ (15,012,913)
Simple Payback Period	Over 15 yrs

COLUMBIA COMMUNITY BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Environmental Value																
Value from Reduced AMR Emissions (Scenario 1)	$ 36	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 1,033
Value from Reduced Outage Response Emissions (Scenario 1)	$ 4	$ 9	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 157
Value from Reduced Generation Emissions (Scenario 1)	$ 13,275	$ 28,210	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 472,929
Service Value																
Enhanced Residential Service Value from Reduced Outage Time (Scenario	$ 3,581	$ 7,647	$ 9,041	$ 9,086	$ 9,131	$ 9,177	$ 9,223	$ 9,269	$ 9,315	$ 9,362	$ 9,408	$ 9,456	$ 9,503	$ 9,551	$ 9,598	$ 132,347
Enhanced Small C&I Service Value from Reduced Outage Time (Scenario 1	$ 202,074	$ 431,544	$ 510,213	$ 512,726	$ 515,332	$ 517,939	$ 520,545	$ 523,152	$ 525,758	$ 528,365	$ 530,971	$ 533,671	$ 536,370	$ 539,070	$ 541,769	$ 7,469,499
Enhanced Large C&I Service Value from Reduced Outage Time (Scenario 1	$ 380,929	$ 813,842	$ 962,599	$ 967,738	$ 972,876	$ 978,015	$ 983,153	$ 988,291	$ 993,430	$ 998,568	$ 1,003,707	$ 1,008,845	$ 1,013,984	$ 1,019,122	$ 1,024,260	$ 14,109,358
Total Community Benefits	$ 599,899	$ 1,281,323	$ 1,515,123	$ 1,522,820	$ 1,530,610	$ 1,538,401	$ 1,546,191	$ 1,553,982	$ 1,561,773	$ 1,569,565	$ 1,577,356	$ 1,585,242	$ 1,593,127	$ 1,601,012	$ 1,608,898	$ 22,185,323
Net Cost/Benefit	$ (16,427,973)	$ (14,828,039)	$ 2,193,859	$ 3,364,836	$ 3,420,719	$ 3,477,817	$ 3,536,160	$ 3,595,777	$ 3,656,734	$ 3,719,026	$ 3,767,243	$ 3,816,494	$ 3,866,709	$ 3,917,912	$ 3,970,130	$ 15,047,404
Cumulative Net Cost/Benefit	$ (16,427,973)	$ (31,256,012)	$ (29,062,153)	$ (25,697,317)	$ (22,276,599)	$ (18,798,782)	$ (15,262,621)	$ (11,666,844)	$ (8,010,110)	$ (4,291,084)	$ (523,841)	$ 3,292,653	$ 7,159,361	$ 11,077,274	$ 15,047,404	

IRR ($)	5.3%
NPV (2013$)	$ 732,625
Simple Payback Period	11.1 yrs

Nominal Case - Without Demand Side Management Programs

Economic Impacts from Smart Grid Implementation and Enhanced Operations - COMPREHENSIVE APPROACH - HOSTED SOLUTION (Scenario 2)

COSTS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
DA Annual Capital Expenditures (Scenario 2)	$ 1,040,102	$ 1,386,803	$ 1,040,102	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 4,299,090
Solution as a Service Hosted AMI/MDMS (Scenario 2) - Electric	$ 3,355,632	$ 3,372,410	$ 3,389,272	$ 3,406,219	$ 3,423,250	$ 3,440,366	$ 3,457,568	$ 3,474,856	$ 3,492,230	$ 3,509,691	$ 3,527,239	$ 3,544,876	$ 3,562,600	$ 3,580,413	$ 3,598,315	$ 52,134,936
Solution as a Service Hosted AMI/MDMS (Scenario 2) - Water	$ 3,334,752	$ 3,351,426	$ 3,368,183	$ 3,385,024	$ 3,401,949	$ 3,418,959	$ 3,436,053	$ 3,453,234	$ 3,470,500	$ 3,487,852	$ 3,505,292	$ 3,522,818	$ 3,540,432	$ 3,558,134	$ 3,575,925	$ 51,810,533
Fiber Integration & Upgrade for Backhaul (Scenario 2)	$ 175,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175,000
PTC Program Costs (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOU/TVR Implementation Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prepay Implementation Costs	$ 130,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 637,958
Total Cost	$ 8,035,486	$ 8,141,389	$ 7,829,076	$ 6,892,889	$ 6,927,653	$ 6,962,607	$ 6,997,752	$ 7,033,090	$ 7,068,622	$ 7,104,349	$ 7,140,274	$ 7,176,387	$ 7,212,719	$ 7,249,243	$ 7,285,970	$ 109,057,517
Contingency (15% excluding hosted service costs)	$ 201,765	$ 212,633	$ 160,743	$ 15,247	$ 15,368	$ 15,492	$ 15,620	$ 15,750	$ 15,884	$ 16,021	$ 16,161	$ 16,305	$ 16,453	$ 16,604	$ 16,759	$ 766,807
Total Cost with Contingency	$ 8,237,252	$ 8,354,022	$ 7,989,819	$ 6,908,136	$ 6,943,021	$ 6,978,099	$ 7,013,372	$ 7,048,840	$ 7,084,506	$ 7,120,370	$ 7,156,435	$ 7,192,702	$ 7,229,172	$ 7,265,847	$ 7,302,729	$ 109,824,324

COLUMBIA DIRECT BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Operational Savings																
Realized Savings from Avoided Meter Reading (Scenario 2)	$ 890,700	$ 912,968	$ 935,792	$ 959,186	$ 983,166	$ 1,007,745	$ 1,032,939	$ 1,058,762	$ 1,085,231	$ 1,112,362	$ 1,140,171	$ 1,168,676	$ 1,197,892	$ 1,227,840	$ 1,258,536	$ 15,971,967
Revenue from Increased Electric Meter Accuracy (Scenario 2)	$ 114,911	$ 118,373	$ 121,939	$ 125,612	$ 129,396	$ 133,294	$ 137,310	$ 141,446	$ 145,707	$ 150,097	$ 154,619	$ 159,276	$ 164,075	$ 169,017	$ 174,109	$ 2,139,183
Revenue from Increased Water Meter Accuracy (Scenario 2)	$ 36,724	$ 37,780	$ 38,868	$ 39,987	$ 41,138	$ 42,323	$ 43,542	$ 44,796	$ 46,087	$ 47,415	$ 48,782	$ 50,188	$ 51,635	$ 53,124	$ 54,656	$ 677,043
Savings from Reduced Meter Reading Safety Risk (Scenario 2)	$ 4,800	$ 4,920	$ 5,043	$ 5,169	$ 5,298	$ 5,431	$ 5,567	$ 5,706	$ 5,848	$ 5,995	$ 6,144	$ 6,298	$ 6,455	$ 6,617	$ 6,782	$ 86,073
Savings from Reduction in Outage Related Calls (Scenario 2)	$ 368	$ 880	$ 1,289	$ 1,322	$ 1,355	$ 1,388	$ 1,423	$ 1,459	$ 1,495	$ 1,533	$ 1,571	$ 1,610	$ 1,650	$ 1,692	$ 1,734	$ 20,769
Savings from Reduced Outage Truck Rolls (Scenario 2)	$ 24,050	$ 32,236	$ 38,873	$ 39,845	$ 40,841	$ 41,862	$ 42,909	$ 43,981	$ 45,081	$ 46,208	$ 47,363	$ 48,547	$ 49,761	$ 51,005	$ 52,280	$ 644,843
Savings from Reduced Connect/Disconnect Truck Rolls (Scenario 2)	$ 114,811	$ 153,890	$ 185,574	$ 190,213	$ 194,968	$ 199,843	$ 204,839	$ 209,960	$ 215,209	$ 220,589	$ 226,104	$ 231,756	$ 237,550	$ 243,489	$ 249,576	$ 3,078,370
Savings from Reduced Transformer Oversizing (Scenario 2)	$ 26,000	$ 34,850	$ 42,025	$ 43,076	$ 44,153	$ 45,256	$ 46,388	$ 47,547	$ 48,736	$ 49,955	$ 51,203	$ 52,483	$ 53,796	$ 55,140	$ 56,519	$ 697,127
Savings from Reduced Debt Write-offs (Scenario 2)	$ 91,439	$ 122,563	$ 147,796	$ 151,491	$ 155,279	$ 159,161	$ 163,140	$ 167,218	$ 171,399	$ 175,684	$ 180,076	$ 184,577	$ 189,192	$ 193,922	$ 198,770	$ 2,451,705
Energy Savings																
Realized Savings from Reduced Energy Losses (Scenario 2)	$ 139,172	$ 326,358	$ 468,557	$ 470,899	$ 473,254	$ 475,620	$ 477,998	$ 480,388	$ 482,790	$ 485,204	$ 487,630	$ 490,068	$ 492,519	$ 494,981	$ 497,456	$ 6,742,895
Realized Savings from Reduced Water Losses (Scenario 2)	$ 360,911	$ 362,715	$ 364,529	$ 366,352	$ 368,183	$ 370,024	$ 371,874	$ 373,734	$ 375,602	$ 377,480	$ 379,368	$ 381,265	$ 383,171	$ 385,087	$ 387,012	$ 5,607,308
Realized Savings from Reduced Theft Losses (Scenario 2)	$ 10,438	$ 24,477	$ 35,142	$ 35,317	$ 35,494	$ 35,672	$ 35,850	$ 36,029	$ 36,209	$ 36,390	$ 36,572	$ 36,755	$ 36,939	$ 37,124	$ 37,309	$ 505,717
Wholesale Energy Savings from Volt/VAR Optimization (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Volt/VAR Optimization (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Residential PCTs (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Residential PCTs (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Residential TOU (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Residential TOU (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Prepay (Scenario 2)	$ 13,312	$ 26,991	$ 41,113	$ 55,652	$ 70,616	$ 86,015	$ 101,856	$ 118,149	$ 134,937	$ 152,196	$ 154,492	$ 156,819	$ 159,177	$ 161,566	$ 163,987	$ 1,596,878
Revenue Loss from Residential Prepay (Scenario 2)	$ (26,911)	$ (55,109)	$ (84,776)	$ (115,898)	$ (148,525)	$ (182,713)	$ (218,515)	$ (255,990)	$ (295,275)	$ (336,355)	$ (344,827)	$ (353,503)	$ (362,388)	$ (371,488)	$ (380,807)	$ (3,533,080)
Peak Energy Savings																
Peak Energy Savings from Residential PCTs (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential PCTs (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peak Energy Savings from Residential TOU (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential TOU (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peak Energy Reduction from Volt/VAR Optimization (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential Volt/VAR Opt. (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Columbia Direct Benefits	$ 1,800,723	$ 2,103,894	$ 2,341,763	$ 2,368,224	$ 2,394,616	$ 2,420,922	$ 2,447,118	$ 2,473,185	$ 2,499,058	$ 2,524,762	$ 2,569,268	$ 2,614,816	$ 2,661,423	$ 2,709,116	$ 2,757,920	$ 36,686,797
Net Cost/Benefit (Without Customer or Community Benefits)	$ (6,436,529)	$ (6,250,128)	$ (5,648,056)	$ (4,539,913)	$ (4,548,405)	$ (4,557,178)	$ (4,566,253)	$ (4,575,655)	$ (4,585,448)	$ (4,595,619)	$ (4,587,167)	$ (4,577,886)	$ (4,567,749)	$ (4,556,732)	$ (4,544,809)	$ (73,137,526)
Cum. Net Cost/Benefit (Without Customer or Community Benefits)	$ (6,436,529)	$ (12,686,657)	$ (18,334,713)	$ (22,874,626)	$ (27,423,031)	$ (31,980,208)	$ (36,546,462)	$ (41,122,117)	$ (45,707,565)	$ (50,303,183)	$ (54,890,351)	$ (59,468,236)	$ (64,035,985)	$ (68,592,717)	$ (73,137,526)	

year$	2013
discount rate	5.0%

IRR ($)	#NUM!
NPV (2013$)	$ (54,219,795)
Simple Payback Period	Over 15 yrs

COLUMBIA CUSTOMER BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Energy Savings																
Customer Savings from Volt/VAR Optimization (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential PCTs (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential TOU (Scenario 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential Prepay (Scenario 2)	$ 26,911	$ 55,109	$ 84,776	$ 115,898	$ 148,525	$ 182,713	$ 218,515	$ 255,990	$ 295,275	$ 336,355	$ 344,827	$ 353,503	$ 362,388	$ 371,488	$ 380,807	$ 3,533,080
Total Columbia Customer Benefits	$ 26,911	$ 55,109	$ 84,776	$ 115,898	$ 148,525	$ 182,713	$ 218,515	$ 255,990	$ 295,275	$ 336,355	$ 344,827	$ 353,503	$ 362,388	$ 371,488	$ 380,807	$ 3,533,080
Net Cost/Benefit (Without Community Benefits)	$ (6,409,617)	$ (6,195,020)	$ (5,563,280)	$ (4,424,015)	$ (4,399,880)	$ (4,374,465)	$ (4,347,738)	$ (4,319,665)	$ (4,290,173)	$ (4,259,264)	$ (4,242,341)	$ (4,224,383)	$ (4,205,361)	$ (4,185,244)	$ (4,164,002)	$ (69,604,447)
Cum. Net Cost/Benefit (Without Community Benefits)	$ (6,409,617)	$ (12,604,637)	$ (18,167,917)	$ (22,591,932)	$ (26,991,811)	$ (31,366,276)	$ (35,714,015)	$ (40,033,679)	$ (44,323,853)	$ (48,583,116)	$ (52,825,457)	$ (57,049,840)	$ (61,255,200)	$ (65,440,444)	$ (69,604,447)	

IRR ($)	#NUM!
NPV (2013$)	$ (51,926,865)
Simple Payback Period	Over 15 yrs

COLUMBIA COMMUNITY BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Environmental Value																
Value from Reduced AMR Emissions (Scenario 2)	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 1,069
Value from Reduced Outage Response Emissions (Scenario 2)	$ 7	$ 9	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 159
Value from Reduced Generation Emissions (Scenario 2)	$ 21,572	$ 28,210	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 481,226
Service Value																
Enhanced Residential Service Value from Reduced Outage Time (Scenario :	$ 5,818	$ 7,647	$ 9,041	$ 9,086	$ 9,131	$ 9,177	$ 9,223	$ 9,269	$ 9,315	$ 9,362	$ 9,408	$ 9,456	$ 9,503	$ 9,551	$ 9,598	$ 134,585
Enhanced Small C&I Service Value from Reduced Outage Time (Scenario 2	$ 328,371	$ 431,544	$ 510,213	$ 512,726	$ 515,332	$ 517,939	$ 520,545	$ 523,152	$ 525,758	$ 528,365	$ 530,971	$ 533,671	$ 536,370	$ 539,070	$ 541,769	$ 7,595,796
Enhanced Large C&I Service Value from Reduced Outage Time (Scenario 2	$ 619,010	$ 813,842	$ 962,599	$ 967,738	$ 972,876	$ 978,015	$ 983,153	$ 988,291	$ 993,430	$ 998,568	$ 1,003,707	$ 1,008,845	$ 1,013,984	$ 1,019,122	$ 1,024,260	$ 14,347,439
Total Community Benefits	$ 974,849	$ 1,281,323	$ 1,515,123	$ 1,522,820	$ 1,530,610	$ 1,538,401	$ 1,546,191	$ 1,553,982	$ 1,561,773	$ 1,569,565	$ 1,577,356	$ 1,586,242	$ 1,593,127	$ 1,601,012	$ 1,608,898	$ 22,560,273
Net Cost/Benefit	$ (5,434,768)	$ (4,913,697)	$ (4,048,157)	$ (2,901,195)	$ (2,869,269)	$ (2,836,065)	$ (2,801,547)	$ (2,765,682)	$ (2,728,400)	$ (2,689,699)	$ (2,664,984)	$ (2,639,141)	$ (2,612,234)	$ (2,584,232)	$ (2,555,104)	$ (47,044,174)
Cumulative Net Cost/Benefit	$ (5,434,768)	$ (10,348,465)	$ (14,396,622)	$ (17,297,817)	$ (20,167,086)	$ (23,003,150)	$ (25,804,697)	$ (28,570,380)	$ (31,298,780)	$ (33,988,479)	$ (36,653,463)	$ (39,292,604)	$ (41,904,838)	$ (44,489,070)	$ (47,044,174)	

IRR ($)	#NUM!
NPV (2013$)	$ (35,806,377)
Simple Payback Period	Over 15 yrs

Nominal Case - Without Demand Side Management Programs

Economic Impacts from Smart Grid Implementation and Enhanced Operations - ENHANCED AMR APPROACH (Scenario 3)

COSTS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
DA Annual Capital Expenditures (Scenario 3)	$ 1,040,102	$ 1,386,803	$ 1,040,102	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 69,340	$ 4,299,090
Advanced Meter Deployment Costs (Scenario 3) - Electric	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Advanced Meter Deployment Costs (Scenario 3) - Water	$ 4,018,250	$ 20,091	$ 20,192	$ 20,293	$ 20,394	$ 20,496	$ 20,599	$ 20,702	$ 20,805	$ 20,909	$ 21,014	$ 21,119	$ 21,224	$ 21,330	$ 21,437	$ 4,308,854
Fixed Metering Network Installation Costs (Scenario 3)	$ 445,900	$ 445,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 891,800
Fiber Integration & Upgrade for Backhaul (Scenario 3)	$ 175,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 175,000
Back Office/Data Management Costs (Scenario 3)	$ 1,000,000	$ 307,500	$ 315,188	$ 323,067	$ 331,144	$ 339,422	$ 347,908	$ 356,606	$ 365,521	$ 374,659	$ 384,025	$ 393,626	$ 403,467	$ 413,553	$ 423,892	$ 6,079,578
PTC Program Costs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOU/TVR Implementation Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Prepay Implementation Costs	$ 130,000	$ 30,750	$ 31,519	$ 32,307	$ 33,114	$ 33,942	$ 34,791	$ 35,661	$ 36,552	$ 37,466	$ 38,403	$ 39,363	$ 40,347	$ 41,355	$ 42,389	$ 637,958
Total Cost	$ 6,809,252	$ 2,191,044	$ 1,407,000	$ 445,007	$ 453,993	$ 463,201	$ 472,638	$ 482,308	$ 492,218	$ 502,374	$ 512,782	$ 523,447	$ 534,378	$ 545,579	$ 557,059	$ 16,392,280
Contingency (15%)	$ 1,021,388	$ 328,657	$ 211,050	$ 66,751	$ 68,099	$ 69,480	$ 70,896	$ 72,346	$ 73,833	$ 75,356	$ 76,917	$ 78,517	$ 80,157	$ 81,837	$ 83,559	$ 2,458,842
Total Cost with Contingency	$ 7,830,640	$ 2,519,701	$ 1,618,050	$ 511,758	$ 522,091	$ 532,681	$ 543,533	$ 554,654	$ 566,051	$ 577,730	$ 589,699	$ 601,965	$ 614,534	$ 627,416	$ 640,617	$ 18,851,122

COLUMBIA DIRECT BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Operational Savings																
Realized Savings from Avoided Meter Reading (Scenario 3)	$ 445,350	$ 912,968	$ 935,792	$ 959,186	$ 983,166	$ 1,007,745	$ 1,032,939	$ 1,058,762	$ 1,085,231	$ 1,112,362	$ 1,140,171	$ 1,168,676	$ 1,197,892	$ 1,227,840	$ 1,258,536	$ 15,526,617
Revenue from Increased Electric Meter Accuracy (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue from Increased Water Meter Accuracy (Scenario 3)	$ 36,724	$ 37,738	$ 38,781	$ 39,852	$ 40,954	$ 42,086	$ 43,250	$ 44,446	$ 45,676	$ 46,940	$ 48,239	$ 49,575	$ 50,948	$ 52,359	$ 53,810	$ 671,377
Savings from Reduced Meter Reading Safety Risk (Scenario 3)	$ 4,800	$ 4,920	$ 5,043	$ 5,169	$ 5,298	$ 5,431	$ 5,567	$ 5,706	$ 5,848	$ 5,995	$ 6,144	$ 6,298	$ 6,455	$ 6,617	$ 6,782	$ 86,073
Savings from Reduction in Outage Related Calls (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Savings from Reduced Outage Truck Rolls (Scenario 3)	$ 24,050	$ 32,236	$ 38,873	$ 39,845	$ 40,841	$ 41,862	$ 42,909	$ 43,981	$ 45,081	$ 46,208	$ 47,363	$ 48,547	$ 49,761	$ 51,005	$ 52,280	$ 644,843
Savings from Reduced Connect/Disconnect Truck Rolls (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Savings from Reduced Transformer Oversizing (Scenario 3)	$ 26,000	$ 34,850	$ 42,025	$ 43,076	$ 44,153	$ 45,256	$ 46,388	$ 47,547	$ 48,736	$ 49,955	$ 51,203	$ 52,483	$ 53,796	$ 55,140	$ 56,519	$ 697,127
Savings from Reduced Debt Write-offs (Scenario 3)	$ 91,439	$ 122,563	$ 147,796	$ 151,491	$ 155,279	$ 159,161	$ 163,140	$ 167,218	$ 171,399	$ 175,684	$ 180,076	$ 184,577	$ 189,192	$ 193,922	$ 198,770	$ 2,451,705
Energy Savings																
Realized Savings from Reduced Energy Losses (Scenario 3)	$ 139,172	$ 326,358	$ 468,557	$ 470,899	$ 473,254	$ 475,620	$ 477,998	$ 480,388	$ 482,790	$ 485,204	$ 487,630	$ 490,068	$ 492,519	$ 494,981	$ 497,456	$ 6,742,895
Realized Savings from Reduced Water Losses (Scenario 3)	$ 360,911	$ 362,715	$ 364,529	$ 366,352	$ 368,183	$ 370,024	$ 371,874	$ 373,734	$ 375,602	$ 377,480	$ 379,368	$ 381,265	$ 383,171	$ 385,087	$ 387,012	$ 5,607,308
Realized Savings from Reduced Theft Losses (Scenario 3)	$ 10,438	$ 24,477	$ 35,142	$ 35,317	$ 35,494	$ 35,672	$ 35,850	$ 36,029	$ 36,209	$ 36,390	$ 36,572	$ 36,755	$ 36,939	$ 37,124	$ 37,309	$ 505,717
Wholesale Energy Savings from Volt/VAR Optimization (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Volt/VAR Optimization (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Residential TOU (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Loss from Residential TOU (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wholesale Energy Savings from Prepay (Scenario 3)	$ 13,312	$ 26,991	$ 41,113	$ 55,652	$ 70,616	$ 86,015	$ 101,856	$ 118,149	$ 134,937	$ 152,196	$ 154,492	$ 156,819	$ 159,177	$ 161,566	$ 163,987	$ 1,596,878
Revenue Loss from Residential Prepay (Scenario 3)	$ (26,911)	$ (55,109)	$ (84,776)	$ (115,898)	$ (148,525)	$ (182,713)	$ (218,515)	$ (255,990)	$ (295,275)	$ (336,355)	$ (344,827)	$ (353,503)	$ (362,388)	$ (371,488)	$ (380,807)	$ (3,533,080)
Peak Energy Savings																
Peak Energy Savings from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peak Energy Savings from Residential TOU (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential TOU (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peak Energy Reduction from Volt/VAR Optimization (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Generation Savings from Residential Volt/VAR Opt. (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Columbia Direct Benefits	$ 1,126,283	$ 1,830,707	$ 2,032,874	$ 2,050,942	$ 2,068,713	$ 2,086,159	$ 2,103,265	$ 2,119,971	$ 2,136,235	$ 2,152,059	$ 2,186,433	$ 2,221,561	$ 2,257,461	$ 2,294,162	$ 2,331,664	$ 30,997,480
Net Cost/Benefit (Without Customer or Community Benefits)	$ (6,705,357)	$ (688,994)	$ 414,823	$ 1,539,185	$ 1,546,621	$ 1,553,478	$ 1,559,722	$ 1,565,317	$ 1,570,185	$ 1,574,328	$ 1,596,734	$ 1,619,596	$ 1,642,927	$ 1,666,736	$ 1,691,037	$ 12,146,338
Cum. Net Cost/Benefit (Without Customer or Community Benefits)	$ (6,705,357)	$ (7,394,351)	$ (6,979,527)	$ (5,440,343)	$ (3,893,721)	$ (2,340,243)	$ (780,521)	$ 784,795	$ 2,354,980	$ 3,929,308	$ 5,526,042	$ 7,145,638	$ 8,788,565	$ 10,455,301	$ 12,146,338	

year$ 2013
discount rate 5.0%

IRR ($)	**13.7%**
NPV (2013$)	**$ 5,767,877**
Simple Payback Period	**7.5 yrs**

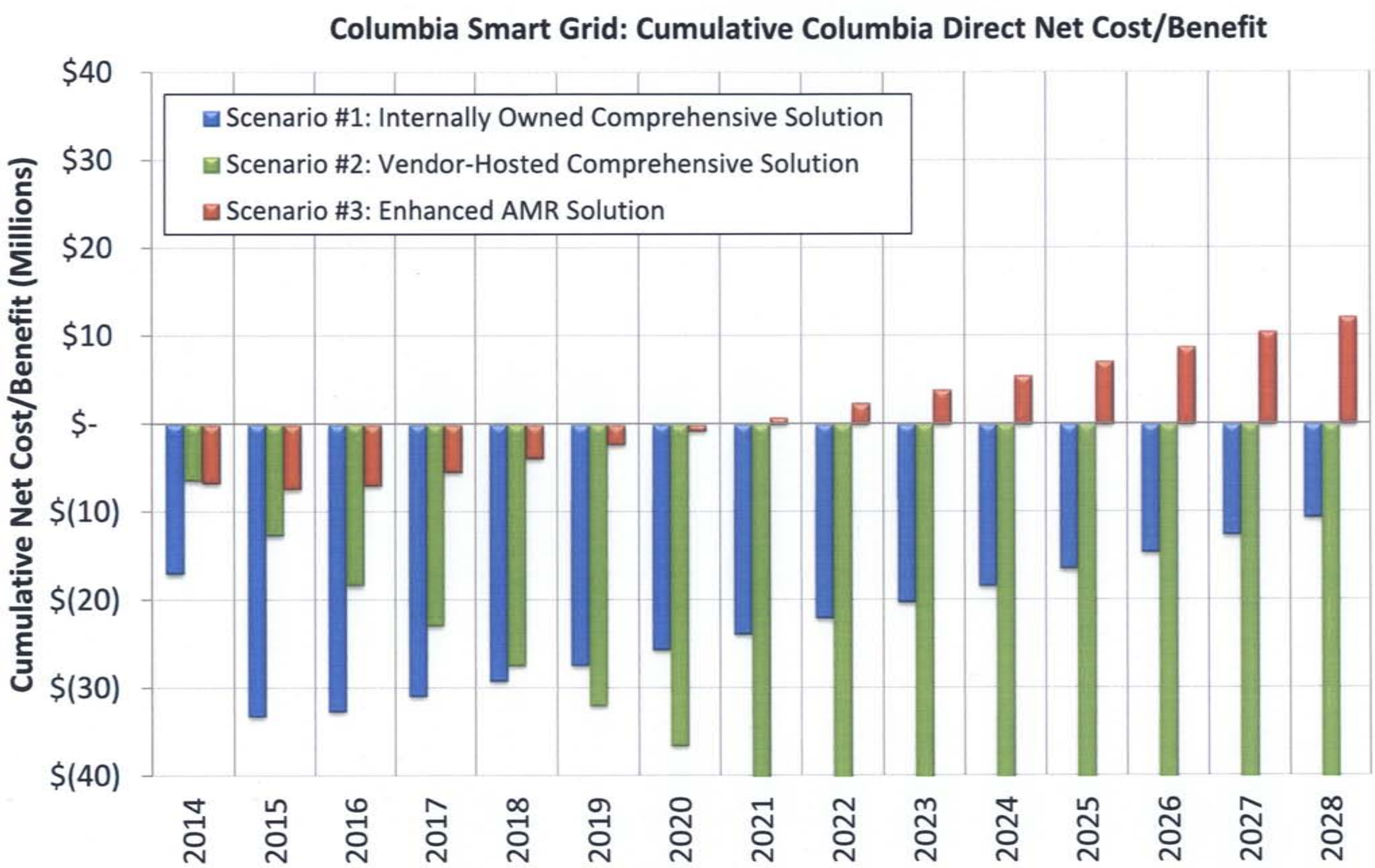
COLUMBIA CUSTOMER BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Energy Savings																
Customer Savings from Volt/VAR Optimization (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential PCTs (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential TOU (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential Prepay (Scenario 3)	$ 26,911	$ 55,109	$ 84,776	$ 115,898	$ 148,525	$ 182,713	$ 218,515	$ 255,990	$ 295,275	$ 336,355	$ 344,827	$ 353,503	$ 362,388	$ 371,488	$ 380,807	$ 3,533,080
Total Columbia Customer Benefits	$ 26,911	$ 55,109	$ 84,776	$ 115,898	$ 148,525	$ 182,713	$ 218,515	$ 255,990	$ 295,275	$ 336,355	$ 344,827	$ 353,503	$ 362,388	$ 371,488	$ 380,807	$ 3,533,080
Net Cost/Benefit (Without Community Benefits)	$ (6,678,446)	$ (633,885)	$ 499,600	$ 1,655,082	$ 1,695,147	$ 1,736,191	$ 1,778,237	$ 1,821,307	$ 1,865,460	$ 1,910,683	$ 1,941,560	$ 1,973,099	$ 2,005,316	$ 2,038,224	$ 2,071,844	$ 15,679,418
Cum. Net Cost/Benefit (Without Community Benefits)	$ (6,678,446)	$ (7,312,331)	$ (6,812,731)	$ (5,157,649)	$ (3,462,502)	$ (1,726,311)	$ 51,926	$ 1,873,233	$ 3,738,692	$ 5,649,376	$ 7,590,936	$ 9,564,035	$ 11,569,350	$ 13,607,574	$ 15,679,418	

IRR ($)	**16.3%**
NPV (2013$)	**$ 8,060,807**
Simple Payback Period	**7 yrs**

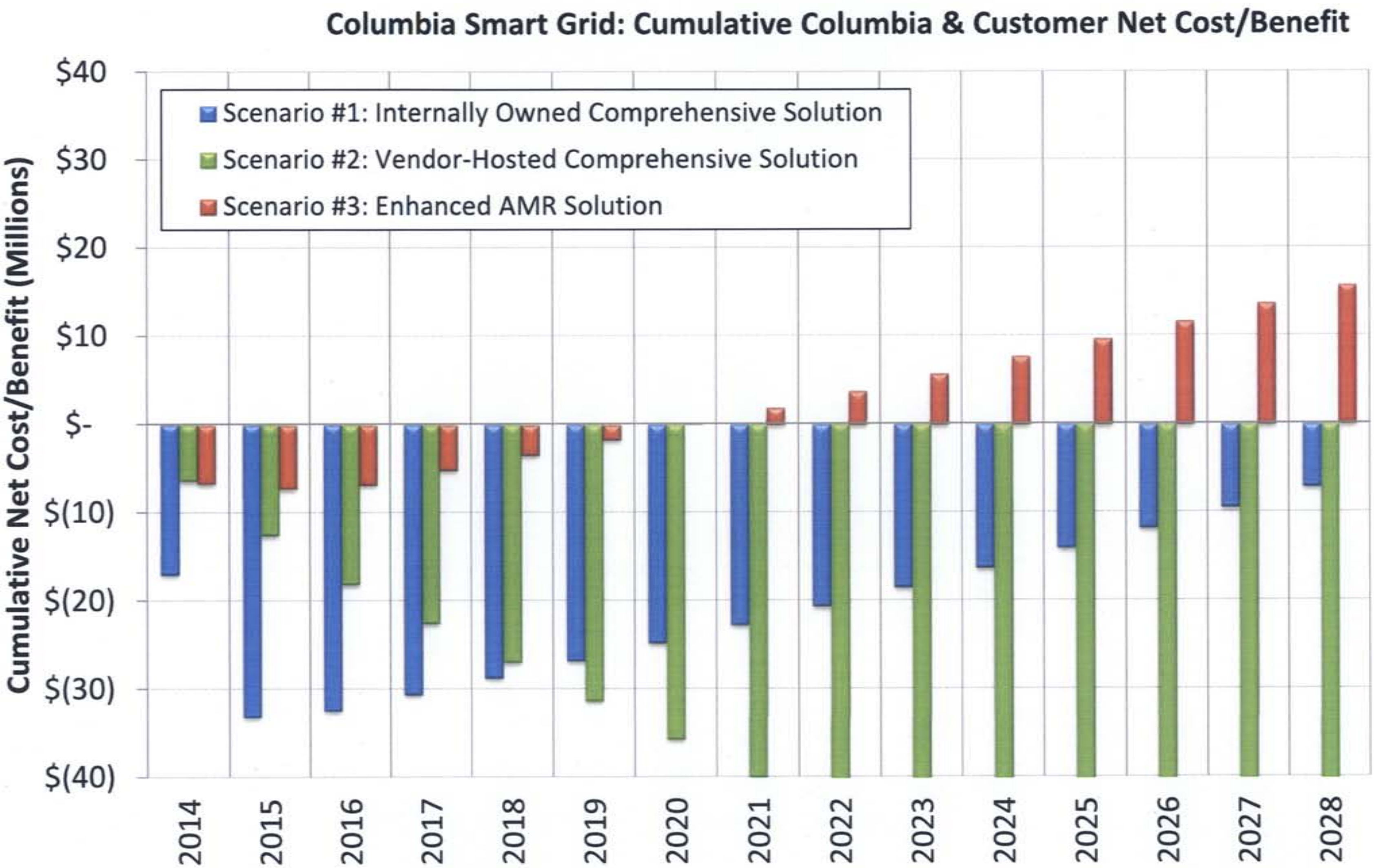
COLUMBIA COMMUNITY BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Environmental Value																
Value from Reduced AMR Emissions (Scenario 3)	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 1,069
Value from Reduced Outage Response Emissions (Scenario 3)	$ 3	$ 8	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 154
Value from Reduced Generation Emissions (Scenario 3)	$ 21,572	$ 28,210	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 33,188	$ 481,226
Service Value																
Enhanced Residential Service Value from Reduced Outage Time (Scenario :	$ 5,818	$ 7,647	$ 9,041	$ 9,086	$ 9,131	$ 9,177	$ 9,223	$ 9,269	$ 9,315	$ 9,362	$ 9,408	$ 9,456	$ 9,503	$ 9,551	$ 9,598	$ 134,585
Enhanced Small C&I Service Value from Reduced Outage Time (Scenario 3	$ 328,371	$ 431,544	$ 510,213	$ 512,726	$ 515,332	$ 517,939	$ 520,545	$ 523,152	$ 525,758	$ 528,365	$ 530,971	$ 533,671	$ 536,370	$ 539,070	$ 541,769	$ 7,595,796
Enhanced Large C&I Service Value from Reduced Outage Time (Scenario 3	$ 619,010	$ 813,842	$ 962,599	$ 967,738	$ 972,876	$ 978,015	$ 983,153	$ 988,291	$ 993,430	$ 998,568	$ 1,003,707	$ 1,008,845	$ 1,013,984	$ 1,019,122	$ 1,024,260	$ 14,347,439
Total Community Benefits	$ 974,845	$ 1,281,322	$ 1,515,123	$ 1,522,820	$ 1,530,610	$ 1,538,401	$ 1,546,191	$ 1,553,982	$ 1,561,773	$ 1,569,565	$ 1,577,356	$ 1,585,242	$ 1,593,127	$ 1,601,012	$ 1,608,898	$ 22,560,267
Net Cost/Benefit	$ (5,703,601)	$ 647,437	$ 2,014,723	$ 3,177,902	$ 3,226,757	$ 3,274,592	$ 3,324,428	$ 3,375,289	$ 3,427,233	$ 3,480,248	$ 3,518,917	$ 3,558,340	$ 3,598,442	$ 3,639,237	$ 3,680,742	$ 38,239,685
Cumulative Net Cost/Benefit	$ (5,703,601)	$ (5,056,164)	$ (3,041,441)	$ 136,461	$ 3,362,218	$ 6,636,809	$ 9,961,238	$ 13,336,526	$ 16,763,759	$ 20,244,007	$ 23,762,924	$ 27,321,265	$ 30,919,706	$ 34,558,943	$ 38,239,685	

IRR ($)	**39.6%**
NPV (2013$)	**$ 24,181,290**
Simple Payback Period	**4 yrs**

Nominal Case - Without Demand Side Management Programs



Nominal Case - Without Demand Side Management Programs



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MISSOURI SMART GRID REPORT

Missouri Public Service Commission

Working Document

EW-2011-0175

Initial Issue
December 10, 2010

Last Updated
February 14, 2014

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MISSOURI SMART GRID REPORT

"PROCEED AT THE RATE OF VALUE"[1]

[1] Theme from NARUC Summer conference, July, 2010.

I. EXECUTIVE SUMMARY

In this updated report, Staff discusses the various Smart Grid technologies, provides a status update on various Smart Grid opportunities in Missouri and presents issues and concerns related to Smart Grid deployment. Staff ultimately recommends the Missouri Public Service Commission (MoPSC) hold periodic workshops to engage stakeholders in meaningful Smart Grid-related discussions. Following is a summary of points highlighted in the report.

- Smart Grid is a rapidly developing, evolving technology with significant promise in several areas for utilities and consumers. Most of the activity in past years has been on the utility grid system but presently there is a major focus and emphasis on smart meter deployments and pilot projects stimulated by American Recovery and Reinvestment Act (ARRA) funding.
- A truly 'Smart' Grid requires in-home and outside-the-home communications systems. This should provide incentives to consumers to reduce energy consumption through demand response (DR).
- Smart Grid technology applied to the electric system transmission and distribution grid should be integrated with two-way communications systems and sensors to allow grid operators to optimize grid performance in real-time and allow the integration of renewable energy sources and distributed generation into the grid.
- Many benefits of the Smart Grid can be realized prior to full Advanced Metering Infrastructure (AMI) smart meter deployment but a complete Smart Grid system includes two-way communications between meters and utilities.
- Missouri has experienced modest growth in advanced meter reading (AMR) and AMI deployment. For Missouri, the top three AMI deployments are Laclede Electric Cooperative with 36,000, Kansas City Power and Light with 14,000 and the City of Fulton with 5,000. The top AMR deployment is Ameren Missouri with 1.2 million meters deployed since 2000.
- Missouri currently has several Smart Grid projects underway in various degrees of development and implementation.

- Communications with customers, consumer education and customer empowerment are just as important as the implementation of new technology in realizing the projected Smart Grid benefits.
- Several industry standards for this evolving technology have been developed and some are still under development. The expectation of seamless integration of new 'smart' technologies with legacy systems and devices cannot be achieved without great attention to the principal of interoperability. Standards-based communications protocols and open architecture must be used. The NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0, provides an overview of the status of standards development.[2]
- There are several communications technologies available to support Smart Grid implementations.

II. INTRODUCTION

Smart Grid is the integration of advanced metering, communications, automation, and information technologies on the electric distribution system to provide an array of energy saving choices and integration of distributed generation while lowering operating costs and maintaining or improving service.[3] Nearly one in every three households has a smart meter accounting for 36 million meters nationwide with projections exceeding 65 million by 2015.[4]

A Smart Grid system could be the enabling technology to allow curtailment of electric usage at critical times, thus, reducing peak demand by not using the most expensive energy sources.

The term 'Smart Grid' does not have a precise definition and there are not exact specifications for the quantity or arrangement of components that make up the Smart Grid deployment, including the equipment, devices, software, processes and procedures required to make the Smart Grid operational in the various unique geographical and cultural locations. The Smart Grid can best be described in terms of the following ability:

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[2] http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf
[3] CNN report "U.S. electricity blackouts skyrocketing", August 2010.
[4] http://www.greenbang.com/how-many-smart-meters-are-there-in-the-us_21821.html

- To develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, and storage, to and from the electric utility system.
- To program any end-use device such as appliances and heating, ventilating and air conditioning (HVAC) systems to respond to communications automatically.
- To sense and localize disruptions or changes in power flows on the grid and communicate such information instantaneously and automatically for purposes of enabling automatic protective responses to sustain reliability and security of grid operations.
- To detect, prevent, respond to, and recover from system security threats such as cyber-security threats and terrorism, using digital technology.
- To use digital controls to manage and modify electricity demand, enable congestion management, assist in voltage control, provide operating reserves, and provide frequency regulation.[5]

III. HISTORY

During the past two decades, non-disaster related outages affecting at least 50,000 consumers increased by 124 percent.[6] The historic August 2003 blackout was initiated by trees falling on power lines causing a cascading set of faults to travel across the overloaded regional grid which left 50 million people without power in eight northeastern states and Canada. [7]

On December 19, 2007, the U.S. Energy Independence and Security Act of 2007 (EISA) was signed into law.[8] Title XIII of EISA is dedicated to the Smart Grid, which according to EISA, is a "modernization of the country's electric power transmission and distribution (T&D) system aimed at maintaining a reliable and secure electricity infrastructure that can meet the increasing demand for electricity." A fundamental assertion of EISA is that

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[5] Energy Independence and Security Act of 2007, Section 1306(d)

[6] CNN report U.S. electricity blackouts skyrocketing, August, 2010 http://www.cnn.com/2010/TECH/innovation/08/09/smart.grid/index.html

[7] Id.

[8] United States Congress (H.R. 6, 110th), Energy Independence and Security Act of 2007 (GovTrack.us database of federal legislation: December 19, 2007); http://www.govtrack.us/congress/bill.xpd?bill=h110-6 (accessed Dec 2, 2008). (U.S.Congress-1)

the existing T&D infrastructure is capable of delivering greater efficiencies, and simply adding more generators and transmission lines is not the sole answer to America's energy needs going forward.[9]

The goal is to use advanced, information-based technologies to increase power grid efficiency, reliability, and flexibility and reduce the rate at which additional electric utility infrastructure needs to be built.[10]

In 2009, the U.S. Congress passed the American Recovery and Reinvestment Act (ARRA), which allocated approximately $3.4 billion in stimulus grant funding for Smart Grid investments. The ARRA provided awarded entities up to 50 percent of the cost of deployment of Smart Grid technologies, including AMI, with a cap of $200 million.

Also in 2009, Congress directed the Federal Communications Commission (FCC) to develop a National Broadband Plan to ensure every American has "access to broadband capability." The National Broadband Plan has recommendations for state regulators that include:[11]

- Requiring electric utilities to provide consumers access to, and control of, their own digital energy information, including real-time information from smart meters and historical consumption, price and bill data over the Internet.
- Carefully evaluating a utility's network requirements and commercial network alternatives before authorizing a rate of return on private communications systems and consider letting recurring network operating costs qualify for a rate of return similar to capitalized utility-build networks.

In recent decades there has been a growing trend toward energy conservation in all aspects of society. Major energy providers have been out in front, minimizing their energy usage through the implementation of energy efficiency measures. Recently, minimizing energy usage and maximizing efficiency has trickled down to end-use industrial, commercial, and residential customers who have implemented measures that include utilizing energy-efficient appliances, equipment and devices.

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[9] NEMA. Standardizing the Classification of Intelligence Levels and Performance of Electricity Supply Chains. Rosslyn, VA: December 2007.
[10] Overview of the Smart Grid-Policies, Initiatives, and Needs, ISO New England, Inc., February 17, 2009.
[11] Connecting America; The National Broadband Plan; http://www.broadband.gov/plan/

In addition to lowering energy usage, there is an increased awareness of the amount of carbon dioxide released into the environment and an interest in moving away from fossil fuels utilized for electric generation and transportation. There is also movement to shift to renewable energy sources (solar, wind, biomass, etc.) that will produce electricity in smaller quantities in more diverse, geographically distributed locations than the traditional central power stations common today.

As these trends mature and gain greater acceptance and implementation, they will place a substantially higher demand on an electric grid system that has aged and was not designed to accommodate an increasing amount of smaller, distributed renewable energy power sources.

IV. SMART GRID IMPACT ON THE ELECTRIC POWER GRID

The electric transmission and distribution grid is evolving into a more reliable system through the integration of two-way communications systems and sensors that allows the optimization of the grid operations in real-time. Staff's research indicates that the current design of the existing grid is based upon the concept of 'one-way' power flow from a generating source, to a transmission line, to a distribution system and then to a commercial, industrial or residential load.

Today's increased emphasis on distributed generation and renewable energy sources will require substantive changes to the, electric grid system Distributed generation sources may include:

- Smaller Fossil-fueled generation
- Combined Heat and Power (CHP)
- Solar Power
- Wind Power
- Stored Energy Sources (batteries, flywheels, compressed air, etc…)
- Plug-in Hybrid Electric Vehicles (PHEVs)
- Electric Vehicles (EV)
- And other potential sources

Modernizing the electric power grid to improve grid operations can include the following enhancements:

A. Installation on the transmission system of Phasor Measurement Units (PMU)

After the August 2003 blackout, the New York State Reliability Council (NYSRC) created a Defensive Strategies Working Group (DSWG) to evaluate ways to mitigate major disturbances on the New York control area. It was determined that under frequency load shedding (UFLS) should be a first line of defense to mitigate major disturbances. NYSRC advocated for the installation of Phasor Measurement Units (PMU) on the transmission system because such devices may offer a simpler method, at reduced costs, for separating sections of the transmission system.

Benefits of a PMU network include enhancements to: network situation alarming; oscillation detection; power plant integration, monitoring and control; planned system separation, reclosing and restoration; and post-event analysis.[12]

B. Overhead and Underground Distribution Sectionalizing Switches

The scope of this enhancement includes the installation of supervisory control and data acquisition (SCADA), or controlled, primary sectionalizing switches on targeted network feeders, to improve the reliability of the overhead distribution systems by enabling rapid isolation of faulted segments of primary feeders and re-energizing the non-faulted portion of the feeder.

C. Capacitor Bank Installations and Phase Monitoring

Installation of automatically controlled or switched capacitor banks will reduce system losses by correcting the power factor and thereby reducing the flow of reactive power through transmission lines, cables, and transformers. Installation will also improve reliability by improving system voltage profile, increasing generator reserve, and improving interface transfer capability to optimize distribution system VAR support for both on-peak and off-peak conditions.

[12] "Order Authorizing Recovery of Costs Associated with Stimulus projects", Cases 09-M-0074 and 09-E-0310, July 27, 2009, by the New York Public Service Commission.

D. Distribution Grid Modernization

This enhancement will modernize the distribution backbone and will include additional distribution capacitor banks, installation of central transformer load tap change (LTC) controller software, installation of SCADA equipment and the development of grid modeling software. These modifications will increase efficiency by reducing losses and increasing reliability by mitigating grid cascades through automated load shedding.

E. Remote Monitoring System (RMS) and High Tension (HT) Feeders

This enhancement includes installation of RMS transmitters on network transformer vault locations to allow operators and engineers to dynamically monitor transformer tank pressure, oil temperature and the oil level that will enable rapid operator response to changes in system conditions.

The remote monitoring of the HT feeders includes upgrading the existing meters with a radio frequency (RF) communications module, which enables improved system planning, remote metering of HT customers and critical load data during contingency situations.

F. Dynamic Secondary Network Modeling and Visualization

This enhancement includes the integrated development and operation of distributed secondary network load flow models that provide near real-time load profiles for customer locations and validates model load flows from secondary models, utilizing the data provided by new remote devices at strategic customer locations. This will help system operator situational awareness and minimize secondary cable failures during peak loading conditions and network outages due to secondary events in the summer.

G. Demand Response Initiatives

This enhancement includes the implementation of a DR monitoring system and deployment of innovative controllable technologies. The DR monitoring system will be a comprehensive software deployment that will aggregate all DR participation in real-time during events. The second component of the DR program will include the installation of equipment and devices such as controllable room and rooftop air conditioning units, Home Area Network (HAN) systems and automatic enabled systems.

The Peak Load Management Alliance (PLMA), founded in 1999 as the national voice of demand response practitioners[13], is a non-profit organization dedicated to providing resources and advocacy toward critical energy management initiatives. This organization consists of experts applying knowledge and skills to address the challenges and opportunities in the rapidly changing energy landscape.

Open Automated Demand Response (OpenADR) provides a non-proprietary, open standardized DR interface that allows electricity providers to communicate DR signals directly to existing customers using a common language and existing communications such as the Internet[14]. OpenADR is currently deployed worldwide and in 2012, the state of California had an enrollment of 260 MW.

H. Combined Heat and Power (CHP)

CHP systems are an efficient form of distributed generation, typically designed to power a single large building, campus or group of facilities and provide power to critical infrastructure during interruptions of service from the electric grid. CHP systems are typically comprised of on-site electrical generators (primarily fueled with natural gas) that achieve high efficiency by capturing heat, a byproduct of electricity production that would otherwise be wasted. The captured heat can be used to provide steam or hot water to the facility for space heating, cooling, or other processes. Capturing and using the waste heat allows CHP systems to reach fuel efficiencies of up to 80 percent, compared with about 45 percent for conventional separate heat and power. CHP systems can use the existing, centralized electricity grid as a backup source to meet peak electricity needs when the CHP system is down for maintenance or in an emergency outage.[15]

On October 28, 2012, Superstorm Sandy caused widespread damage and economic losses across New Jersey, New York, and Connecticut with extended power outages affecting the region for days.

In response to Executive Order 13632, in August 2013, the Federal Hurricane Sandy Rebuilding Task Force published a Hurricane Sandy Rebuilding Strategy that describes how CHP played a successful role in keeping a number of college campuses, multifamily housing,

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[13] http://www.peaklma.org/
[14] http://www.openadr.org/
[15] https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf

critical medical facilities, sewage treatment plants and other facilities running during and after the storm. The DOE published the "Guide to Using Combined Heat and Power for Enhancing Reliability and Resiliency in Buildings" in September 2013.[16] In March 2013, ICF International published a report titled "Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities" for the Oak Ridge National Laboratory.[17]

These reports provide an overview of CHP and examples of how this technology can help improve the resiliency and reliability of key infrastructure, although Missouri-specific information is limited.

V. ELECTRIC USAGE METERS

One of the key components of the Smart Grid that has received a lot of media attention is the electric meter whose basic functions are to measure the amount of electricity used by the consumer and also provide the physical interface point between the consumer and electricity supplier. There are basically three types of electric usage meters in use today: – electro-mechanical meters, automated meter reading, automated metering infrastructure.

A. Electro-mechanical Meters.

The most common type of electricity meter used by electric utilities is the Thomson or electro-mechanical induction watt-hour meter, invented by Elihu Thomson of the American General Electric Company around 1889. In 1894, Oliver Shallenberger of the Westinghouse Electric Corporation refined this induction meter to produce a watt-hour meter of the modern electro-mechanical form, using an induction disk whose rotational speed was made proportional to the power in the circuit.[18] The electro-mechanical induction meter operates by counting the revolutions of an aluminum disc which is made to rotate at a speed proportional to the power. The meter is reportedly very robust and reliable with accuracy typically of 1 percent and a range of 1 percent - 2 percent as governed by American National Standards Institute (ANSI) standard C12.1. In 1998, there were only four US vendors offering electro-mechanical meters and, currently, they are primarily being manufactured in China.

[16] http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_for_reliability_guidance.pdf
[17] https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf
[18] Wikipedia

B. Automated Meter Reading (AMR).

Automated meter reading, or AMR, is the technology of automatically collecting consumption, diagnostic, and status data from electric metering devices and transferring that data via one-way communication, to a central database for billing, troubleshooting, and analyzing. This advancement mainly saves utility providers the expense of periodic trips to each physical location to read a meter. AMR technologies include handheld, mobile and network technologies based on telephony platforms (wired and wireless), RF, or power-line transmission for communications of the data.

C. Advanced Metering Infrastructure (AMI).

Advanced Metering Infrastructure or AMI refers to systems that measure, collect and analyze energy usage, and interact with advanced devices such as electric meters through various two-way communications media either on request (on-demand) or on pre-defined schedules. The required infrastructure to support AMI applications includes hardware, software, communications, consumer energy displays and controllers, customer associated systems, and communications networks and interfaces.

The Department of Energy (DOE) reports an increasing amount of collaboration and alliance between smart meter vendors and other vendors providing software and hardware that support smart meter deployment.[19] "The meter is very accurate with an accuracy of typically .5 percent and a range of .5 percent -1 percent as governed by ANSI standard C12.20." Today there are at least six vendors offering these types of meters.

Type & Number of US Utilities with AMI by Customer Type[20]

Utility Type	Utilities	Residential	Commercial	Industrial	Transportation	Totals
Investor	73	25,891,279	2,886,498	78,688	4	28,856,469
COOP	311	5,017,654	495,609	47,667	0	5,560,930
Muni	84	1,116,675	149,323	4,870	0	1,270,868
Public & State	24	1,427,940	150,729	23,434	3	1,602,106
Totals	493	33,453,548	3,682,159	154,660	7	37,290,374

[19] http://www.energy.gov/news/documents/Smart-Grid-Vendor.pdf
[20] http://www.eia.gov/tools/faqs/faq.cfm?id=108&t=3

The following US utilities were scheduled to complete their AMI deployments by the end of 2012:[21]

- Alabama Power (AL)
- Pacific Gas & Electric (CA)
- Sacramento Municipal Utility District (CA)
- San Diego Gas & Electric (CA)
- Southern California Edison (CA)
- Black Hills Energy Corp (CO)
- Pepco (DC)
- Delmarva Power (DE)
- Gulf Power (FL)
- Georgia Power (GA)
- Idaho Power (ID);
- Bangor Hydro Electric Company (ME)
- Central Maine Power (ME)
- NV Energy (NV); Idaho Power (OR)
- Portland General Electric (OR)
- PPL (PA)
- Black Hills Power (SD)
- Austin Energy(TX)
- CenterPoint Energy (TX)
- Oncor (TX)
- Wisconsin Power and Light (WI)
- Cheyenne Light, Fuel, and Power (WY)
- Black Hills Power (WY)

In Missouri, the top three AMI deployments are Laclede Electric Cooperative with 36,000, Kansas City Power and Light (KCP&L) with 14,000 and the City of Fulton with 5,000.

Issues with AMI Implementation

Issues with smart meter deployment have involved customer outrage directed at PG&E in California and ONCOR in Texas. Further, the Maryland Public Service Commission (MdPSC) recently rejected Baltimore Gas and Electric's (BG&E) plan for deployment.[22] In April 2010, a state senate hearing forced PG&E to disclose information concerning problems with smart meters. PG&E found issues with faulty installations, loss of customer usage information and trouble sending information back to the utility.[23] Only a very small percentage of meters had accuracy issues.[24] The Texas Public Utility Commission ordered an independent investigation into the accuracy of installed meters. Independent

[21] http://www.edisonfoundation.net/iee/Documents/IEE_SmartMeterRollouts_0512.pdf
[22] Anti-Meter Fever Spreads as Regulator and Customer Mistrust Grows, SmartGridNews.com, February, 2010
[23] Consumers wary of smart meters, stateline.org story, July 23, 2010.
[24] "PG&E Advanced Metering Assessment" report, September 2, 2010, by the California Public Utilities Commission prepared by Structure Consulting Group, LLC.

accuracy tests were conducted by Navigant Consulting, LLC, which found that 99.96 percent meters were determined to be accurate to ANSI standards.[25]

In Order No. 83410, Case NO. 9208, the MdPSC noted the following involving the rejection of BG&E's $835 million smart-meter installation plan:

- BG&E ratepayers should not be exposed to all the financial risk of an unproven and evolving technology and the accuracy of the assumptions used in the BG&E business case.
- The MdPSC will not approve cost recovery by way of a surcharge and prefers recovery through a regulatory asset because the project is viewed as a classic utility infrastructure investment.
- Before implementing time of use rates, it is critical that customers be provided sufficient education to understand the new tariff and how their behavior and decisions will impact their bill.
- Customers need to be provided sufficient enabling technology such as in-home displays (IHDs), energy orbs, messaging, etc., to provide the information that will trigger behavior changes aimed at reducing their electric bill.[26]

The MdPSC approved a revised BG&E submittal that incorporates its direction that the Smart Grid project be treated as a regulatory asset, similar to a new power plant, and BG&E should recoup its costs through base-rate increases, not through surcharges. The MdPSC said it would perform an ongoing review of BG&E's costs and recovery, allowing the company to raise rates, once it has 'delivered a cost-effective AMI system.'[27]

The Hawaii Public Utilities Commission (HPUC) denied a request by Hawaiian Electric Company (HECO) to extend pilot testing for its AMI project to 5,000 smart meters because of cost concerns.

HECO said that additional pilot testing would be necessary to understand, in detail, how advanced metering would work with a new customer information system. The HPUC said that HECO could not proceed with the plans outlined in its original application without

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[25] Evaluation of Advanced Metering System (AMS) Deployment in Texas, Report of Investigation, July 30, 2010. http://www.puc.state.tx.us/electric/reports/ams/PUCT-Final-Report_073010.pdf
[26] "Maryland Regulators Approve BGE's Revised Smart Grid Proposal", August 17, 2010, SustainableBusiness.com News; http://www.sustainablebusiness.com/index.cfm/go/news.display/id/20873
[27] Ibid

engaging in the extended pilot testing and wrote that "any new AMI or, preferably, AMI/Smart Grid application should include or be preceded by an overall Smart Grid plan or proposal filed with the [HPUC]."[28]

Communication Networks and Protocols

A logistical area of concern is that, traditionally, electric utilities have no precedent or demonstrated skill at successfully building and operating telecommunications networks comprised of vast numbers of nodes that are required to provide high-accuracy and reliability for daily transport of meter-derived power consumption data.

The protocol debate promises to become one of the dominant issues in Smart Grid over the next several years. Various vendors have proposed solutions for linking homes, substations, transformers and all of the other machines that bring electricity to the house. Some companies have also proposed licensable proprietary standards that potentially could become de facto standards. Utilities have responded by either adopting these technologies for commercial Smart Grid deployments or at least agreeing to test them in trials.

Several electric cooperatives in Missouri utilize the MultiSpeak® Initiative for efficient communication integration, including: Boone Electric Cooperative, CO-MO Electric Cooperative, Laclede Electric Cooperative, Platte-Clay Electric Cooperative, Southwest Electric Cooperative and White River Valley Electric Cooperative. The MultiSpeak® Initiative is a collaboration of the National Rural Electric Cooperative Association (NRECA) and software vendors supplying the utility market and utilities, and is a project that is gaining national and international acceptance. (NIST, ANSI, IEC Wg14)[29] NRECA's MultiSpeak® is an industry-wide software standard that facilitates interoperability of diverse business and automation applications used in electric utilities. The MultiSpeak® Initiative has developed and continues to modify the specification that defines standardized interfaces among software applications commonly used by electric utilities so that software products from different suppliers can interoperate without requiring the development of extensive custom interfaces.[30] MultiSpeak® provides the following functions:

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[28] Power news article, August 10,2010, http://www.powermag.com/smart_grid/Hawaii-PUC-Rejects-Smart-Grid-Proposal_2917.html

[29] Technical Presentation by Gregory Wolven, WinEnergy, at Tech Advantage 2010 Conference and Expo.

[30] http://www.multispeak.org/About/whatIsMultiSpeak.html

i. Distribution System Monitoring that includes meter reading, load profile creation and connect/disconnect functions.

ii. Business Functions External to Distribution Management that includes meter data management, finance and accounting, customer billing, customer relationship management, end device testing and receiving, payment processing and prepaid metering.

iii. Distribution Operations that include call handling, outage detection and management, load management, distribution automation data, supervisory control and data acquisition, and distribution automation control.

iv. Distribution Engineering, Planning, Construction, and Geographic Information Systems that include engineering analysis and field design.[31]

Radio Frequency (RF) radiation concerns

There is debate concerning the amount of radio frequency (RF) radiation that is emitted from AMI or smart meters. RF and microwave (MW) radiation are electromagnetic radiation (non-ionizing[32]) in the frequency ranges 3 kilohertz (kHz) - 300 Megahertz (MHz), and 300 MHz - 300 gigahertz (GHz), respectively.[33] Smart Meters typically contain two wireless transmitters; one to transmit information back to the utility via the Wide Area Network (WAN) at a nominal power output range of .25 to 1 watt at a nominal frequency range of .8 to 1.9 GHz and a second to transmit inside the building using the Home Area Network (HAN) at a typical power level of .2 watts at a frequency of 2.4 GHz.[34] The current Federal Communications Commission (FCC) guidelines on exposure to RF radiation were published in 1996 and provide an adequate level of safety against known thermally induced health impacts of smart meters.[35] The CCST report entitled "Health Impacts of Radio Frequency from Smart Meters"released in March 2011[36] stated that the RF emissions levels of Smart Meters are measurably less than from microwave ovens or cell phones and scientific studies have not identified or confirmed negative health resulting from the RF emissions of

[31] http://www.multispeak.org/About/whatIsMultiSpeakcovers.htm
[32] http://en.wikipedia.org/wiki/Radiation
[33] https://www.osha.gov/SLTC/radiofrequencyradiation/
[34] http://www.ccst.us/publications/2011/2011smart.php
[35] http://www.metering.com/node/18864
[36] http://www.ccst.us/news/2011/20110111smart.php

common household appliances or smart meters.[37] A typical power output from a home wireless network router is .25 watt with a peak limit of 1 watt.[38]

The peak magnitude of RF emissions from smart meters is greatest at the front of the meter (facing away from the building or house and transmitting to the WAN requires more power due to the distance required versus the HAN) and decreases in magnitude as a function of the distance from the meter. In addition, these meters only emit the peak RF emissions when they are transmitting information back to the utility's network and the frequency of transmission can vary depending on the type of installed communication network. [39]

Communication Systems & Networks of AMI Meters:

Several network infrastructures and information technologies are available to support AMI deployment that include Microwave, Wireless Metropolitan Area Network (WIMAX), Outdoor Wireless Mesh Network (WMN or MESH), Long Term Evolution (LTE), 3G Cellular, Power Line Carrier, Wireline Broadband, Wireless Local Area Network (WLAN) and Zigbee.[40] While there are several technologies to consider, there are basically three separate communications systems required: the Wide or Wireless Area Network (WAN) from the utility access point back to the utility, the Neighborhood Area Network (NAN) outside from the meter to the utility access point and the Home Area Network (HAN) inside the residential home, commercial business or industrial facility.

The Neighborhood Area Network (NAN):

One communications system with two different networks is required to transmit data between the meter and the utility's collection or infrastructure support system. The first network supports communications between the meter and the utilities data collection point and is commonly referred to as a the NAN.

The Home Area Network (HAN):

Inside the home or business, a second communications system is required. Commonly referred to as the HAN, it also has some options for network architecture and communications protocols.

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[37] http://www.ccst.us/publications/2011/2011smart.php
[38] http://www.wirelessforums.org/alt-internet-wireless/output-power-linksys-router-20811.html
[39] http://www.eiwellspring.org/smartmeter/Measured_RF_from_smartmeters.htm
[40] Smart Grid Wireless Technology Comparison Chart from Aviat Networks; http://www.aviatnetworks.com

The current in-home applications, which utilize smart thermostats, individual receptacle switches, and specific device switches for water heaters, central air conditioners and smart appliances, require low speed and bandwidth.

For these types of applications, a HAN Device Portal Architecture consisting of a communication gateway with a Zigbee Smart Energy Profile is the most widely used.[41] A recent General Electric paper concluded that the two wireless communication technologies that best meet the overall requirements for this application are Wi-Fi (IEEE 8021.11) and Zigbee (IEEE 802.15.4), with Zigbee preferred based upon lower energy consumption.[42] The Zigbee Smart Energy Profile has been endorsed by NIST as a national, U.S. Smart Grid standard.[43]

The Communication Gateway:

A communication gateway device is required to facilitate communication between the NAN and HAN networks.

The gateway device serves as a 'translator' for the two-way communications that are required between the NAN and HAN networks, which have different communication protocols or 'speak different languages'. This separate device should be external to the Smart Meter so communication protocol changes can be made without changing out the installed Smart Meter.[44]

Open technology and open non-discriminatory access to data can lead to new levels of services to consumers in the areas of demand response, information technology and price offerings.[45] While there is a lot of attention on the electric meter, a June 29, 2010 American Council for an Energy-Efficient Economy (ACEEE) report indicates in its opinion, smart meters alone are not sufficient for customers to realize energy savings; customer education is

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[41] PennEnergy report; "The Home Area Network; Architectural Considerations for Rapid Innovation." http://www.pennenergy.com/index/power/smart-grid/display/3151828412/articles/pennenergy/ugc/smart-grid/the-home-area-network-architectural-considerations-for-rapid-innovation.html

[42] General Electric Paper, "Energy Efficiency Comparisons of Wireless Communication Technology Options for Smart Grid Enabled Devices", December 9, 2010.

[43] Smart Grid Watch, "Is it Game Over for the Winning Home Area Network Wireless Standard" http://www.emeter.com/2010/is-it-game-over-for-the-winning-home-area-network-wireless-standard/

[44] PennEnergy report; "The Home Area Network; Architectural Considerations for Rapid Innovation. http://www.pennenergy.com/index/power/smart-grid/display/3151828412/articles/pennenergy/ugc/smart-grid/the-home-area-network-architectural-considerations-for-rapid-innovation.html

[45] "Order Authorizing Recovery of Costs Associated with Stimulus projects", Cases 09-M-0074 and 09-E-0310, July 27, 2009, by the New York Public Service Commission.

required to meet projected energy savings goals.[46] As an example of the importance of consumer education, the Denmark energy company SEAS-NV initiated a competition where customers submit monthly meter readings via the internet or cellular phone text for a chance to win a monthly prize. The readings were also used to classify each contestant in an energy class in order to raise awareness of their energy consumption and provide customers individualized consulting on how to reduce their consumption. Customers who participated in this project reduced their consumption by an average of 17%.[47]

VI. CUSTOMER EDUCATION, INDUSTRY INITIATIVES AND STANDARDS

A. Customer Education

In the emerging Smart Grid, many studies have been done that are leading to the same general conclusion. A rational, technical, and one-sided approach, alone, will not be effective in driving Smart Grid customer engagement. The experience of the customer must be positive, and balance both the rational (price incentive, multiple forms of relaying information) and emotional (normative comparisons, environmental advantages, social implications) relationships.

There are multiple ways to build and foster this positive relationship and as the engagement and relationships evolve, the utility has to be willing to enhance its customer care to maintain these relationships. The utilities must also receive and give persistent feedback to evaluate where they are and in which direction their ideas/pilots/projects need to go. Some customer segments will react well to certain approaches, some segments to other approaches.[48] The utilities should evolve the approaches that work using a positive feedback loop, alternate approaches, or cut the ineffective approaches.[49]

There are many means currently available to communicate energy usage to consumers. Single socket plug-ins, whole-home energy trackers, energy ratings, etc. are currently in the

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[46] Special Report Number E105, Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities by ACEEE on Advanced Metering, June, 2010.

[47] European Utility Awards; http://www.european-utility-awards.com/EUA/Past_Winners_2290.aspx

[48] Customers as Co-Creators of Value: A Social Roadmap for the Smart Grid Peter C. Honebein | © 2010 Customer Performance Group | IEE Webinar August 16, 20101

[49] The OPOWER Approach: Advanced Customer Engagement (ACE)

market ready to be used, and are being utilized in many cases. Making these tools readily available and informing the public are the two main hurdles.

It is not necessary to have a Smart Grid in place to enable a significant and positive behavior change. Right now, statistical methods that analyze existing utility and other available data can be used to provide useful and educational consumer feedback. ... Another existing technology approach that can enable both demand response and a more compelling energy efficiency behavior is to tap into mobile phone technology. In 2012, 88 percent of Americans had mobile phones and 46 percent of those were smartphones.[50] It is reported that if even 20 percent of homeowners managed their energy load using their mobile phone, it could result in a major reduction in electricity waste.[51]

The estimated amount of consumer energy cost savings are often quite different than the actual savings realized by the customer. Benefits are often stated in the 10-14 percent range while, once implemented and measured, the savings are more in the 5-8 percent range. Managing customer expectations is crucial to program success. If savings are much lower than anticipated, the whole program could receive negative feedback.

Some key communication lessons include:

- AMI represents just one of several means of providing households with real-time feedback.
- The success of the Smart Grid, advanced metering, and energy management and home automation technologies depends heavily on consumer acceptance and participation.
- Third-party providers are likely to be important players in feedback solutions, whether working in conjunction with or independently of utilities.
- Feedback gadgets alone are unlikely to maximize household energy savings.
- The best feedback approaches are likely to be incremental in nature and will 'evolve' as technologies become more sophisticated.

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[50] http://pewinternet.org/Reports/2012/Smartphone-Update-2012/Findings.aspx

[51] Special Report Number E105, Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities by ACEEE on Advanced Metering, June, 2010.

- The future of home energy management is likely to involve a complex network of wireless, consumer-controlled, home automation systems; although less sophisticated automation devices can be supported presently.[52]

B. Green Button Initiative

"'Green Button' is an industry-led effort that responds to a White House call-to-action to: Provide electricity customers with easy access to their energy usage data in a consumer-friendly and computer-friendly format via a "Green Button" on electric utilities' website. Green Button is based on a common technical standard developed in collaboration with a public-private partnership supported by the Commerce Department's National Institute of Standards and Technology. Voluntary adoption of a consensus standard by utilities across the Nation allow software developers and other entrepreneurs to leverage a sufficiently large market to support the creation of innovative applications that can help consumers make the most of their energy usage information.

Initially launched in January 2012, utilities committed to provide Green Button capability to nearly 12 million households in 2012. Two utilities - Pacific Gas & Electric and San Diego Gas & Electric - have implemented live functionality on their websites. Recently, nine major utilities and electricity suppliers signed on to the initiative, committing to provide more than 15 million households secure access to their energy data with a simple click of an online Green Button. In total, these commitments ensure that 27 million households will be able to access their own energy information, and this number will continue to grow as utilities nation-wide voluntarily make energy data more available in this common, machine-readable format."[53]

C. Industry Standards

The National Institute of Standards and Technology (NIST) is the governing body charged with developing nation-wide standards for all areas of Smart Grid. NIST is currently involved with more than 100 organizations and stakeholders. NIST developed the Smart Grid Interoperability Panel (SGIP) to guide and nurture the long-term Smart Grid evolution. NIST

[52] Special Report Number E105, Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities by ACEEE on Advanced Metering, June, 2010.
[53] http://www.greenbuttondata.org/greenabout.html

also developed 17 priority action plans (PAPs). The PAPs define the problem, establish the objectives, and identify the likely standards bodies and user associations pertinent to standards modifications, enhancements, and harmonization.[54]

Standard(s) development began in 2007. The FERC initiated a formal rulemaking proceeding on October 7, 2010 by creating docket RM11-2-000 for consideration of the five groups of Smart Grid operability standards identified by the NIST.[55] These five groups of standards will address open and non-proprietary communications protocols and cyber security. The NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0,[56] includes a description of the Smart Grid conceptual reference model and conceptual architectural framework under development by the SGIP's Smart Grid Architecture Committee (SGAC), an update to the progress of the PAPs, a listing of new standards emerging from the PAPs, a description of the recently formed Smart Grid Interoperability Panel (SGIP), a Cybersecurity section and a testing and certification section.

The North American Energy Standards Board (NAESB) is involved in developing smart grid standards and serves as an industry forum for the development and promotion of standards which will lead to a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities.[57] The Smart Grid Interoperability Panel maintains a catalog compendium of Smart Grid Standards.[58]

The New York Public Service Commission stated, "The expectation of seamless integration of new 'smart' technologies with legacy systems and devices cannot be achieved without great attention to the principal of interoperability. ... Interoperability promotes technology innovation, operational efficiency and facilitates the scalability, security, and reliability of Smart Grid deployments. Although development of a comprehensive set of Smart Grid standards is not entirely complete, the principals of interoperability, standards-based communications protocols, and open architecture must be incorporated in current Smart Grid deployments. It is essential that the concept of interoperability not be limited to

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[54] http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/WebHome
[55] FERC Docket No. RM11-2-000, "NOTICE OF DOCKET DESIGNATION FOR SMART GRID INTEROPERABILITY STANDARDS"
[56] http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf
[57] http://www.naesb.org/
[58] http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/StandardOperatingProcedures/Standards_Catalog_Process_and_Structure_V1_0.pdf

informational compatibility between Smart Grid systems. Greater interoperability and standards development should also drive innovation and competition among device manufacturers, increasing vendor choice and communications technology alternatives, ultimately leading to more cost-effective deployments."[59]

VII. PROCESSES, ISSUES & GOALS FOR MISSOURI

There are many unique processes and goals in the Smart Grid discussion Openly discussing these issues with all stakeholders is key to developing a pathway that is best for the state of Missouri.

Planning and implementation are the key foundational processes that must be addressed before any significant progress can be made. There are key planning and implementation issues that many IOUs in Missouri are addressing:

- Ameren Missouri[60] has cost benefit studies that indicate replacing AMR meters before their normal replacement interval and transitioning to an AMI implementation would not be cost effective. Ameren Missouri is now planning a transition to AMI meters starting in 2015.
- Kansas City Power & Light is well into the implementation phase for its pilot project in the Kansas City area.
- Empire District Electric is currently in the early planning stages of its Smart Grid initiatives.

The MoPSC has held stakeholder meetings and technical workshops/conferences for dialogues and collaboration between businesses, customers, utilities and regulators. Major goals of the planning and implementation phases are to consider all alternatives and select the alternatives that would be beneficial to the most customers without having negative consequences in the areas of reliability, costs or availability.

Different IOUs are in different stages of implementation, and as implementation begins, issues will inevitably arise. Cost recovery, security, customer relations, benefits with the new systems, and reliability are all major concerns for new systems.

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[59] "Order Authorizing Recovery of Costs Associated with Stimulus projects", Cases 09-M-0074 and 09-E-0310, July 27, 2009, by the New York Public Service Commission.
[60] As used in this report, AmerenUE is the same as Ameren Missouri.

These concerns should be addressed in workgroups now and as they represent potential hurdles in the future. The overall goal of implementation is to smoothly deploy Smart Grid and all necessary hardware and software without any loss of reliability. Periodic workshops/technical conferences are suggested to address new issues as they arise, and to resolve any current or past conflicts that have not been properly addressed. These workshops/technical conferences have been very successful and well received by all stakeholders and bring in a wide variety of experience, solutions and/or ideas that can help navigate the ever-evolving Smart Grid.

VIII. SMART GRID PILOT/DEMONSTRATION PROJECTS IN MISSOURI

A. The City of Fulton[61]

The City of Fulton municipal electric utility was one of 100 recipients of the DOE's Smart Grid Grant awards on October 30, 2009. The City's share of the grant award is just over $1.5 million, which was matched by the city. The City's project will replace more than 5,000 electric meters with an AMI smart meter network that includes a dynamic pricing program with in-home energy displays to reduce consumer energy use.

The City also made an additional commitment of $1 million for gas and water meter improvements and will also include the installation of 2-3 vehicle charging stations. In April 2011, the City awarded a $2.14 million contract to Tantalus for system integration and implementation.[62] The Electric AMI meters are GE single phase residential with a remote disconnect feature. Customers do not have an "Opt Out" option for the new AMI meters and the city is looking at different rate structures to offer new tiered rate structure and time-of-use rate to customers.

The City has a "Smart Grid Bill of Rights"[63] that outlines the rights of customers with respect to the Smart Grid and guarantees the following:

- The Right To Be Informed
- The Right To Privacy

[61] http://psc.mo.gov/CMSInternetData/Electric/Smart%20Grid/Happening%20in%20MO/Kyle%20Bruemmer%20presentation.pdf
[62] http://www.fultonsun.com/news/2011/apr/15/council-oks-smart-grid-bid/
[63] http://fultonmo.org/departments/utilities/smart-grid/sg-bor/

- The Right To Options
- The Right To Data Security

The gas and water meters are upgraded to AMR and fitted with a Badger module to communicate over the Tantalus network. There are a total of 5,505 AMI meters deployed with 4,359 of these for residential, 916 for commercial and 50 for industrial customers. The network communications protocol is Multi-Speak and the city is deploying a Meter Data Management system to create a customer web portal and customer usage reports. The Home Area Network is a 900 MHz mesh network, and there are approximately 100 programmable smart communicating thermostats being deployed.

The City plans to use the AMI system to also deploy demand response to decrease the amount of purchased power required and plans to pass the savings on to its customers. The City wants to deploy a demand response program similar to KCPL's "M Power". The City is also in the initial planning stages to deploy a voltage control system similar to Ameren Missouri which they estimate will result in a 3 percent energy savings.[64]

B. KCP&L Company's Smart Grid Demonstration Project[65]

The KCP&L Smart Grid demonstration project (Project) is included in the Department of Energy (DOE) and Electric Power Research Institute (EPRI) demonstration programs.[66] The Project is located in an economically challenged area of Kansas City, Missouri. The Project's expectations are that the Project will deliver benefits to the immediate targeted end-users and provide valuable experience and lessons for future applications. Project funding consists of approximately $48.1 million to be spent from 2010 through 2014, of which $13.8 million (29%) is KCP&L-funded, $10.2 million (21%) is partner/vendor-funded and $24.1 million (50%) is federally-funded through the ARRA.[67] KCP&L teamed with Siemens Energy, Inc., Open Access Technology, Inc. (OATI), Landis&Gyr AG, GridPoint, Inc., Kokam America, Inc., EPRI and Honeywell International, Inc.[68]

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[64] http://energy.gov/sites/prod/files/SGIG%20Awards%20%20By%20State%202011%2011%2015.pdf and http://www.smartgrid.gov/project/city_fulton_missourismart_grid_project/latest_data

[65]: http://ala.kcpl.com/about/policycenter/SmartGridGIZmap.pdf and http://www.kcpl.com/about/policyctr.html

[66] Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.

[67] KCP&L Green Impact Zone Smart Grid Demonstration submitted to the DOE, August 26, 2009.

[68] Ibid

The Project is being promoted as an end-to-end Smart Grid that will include advanced metering infrastructure (AMI), renewable generation, energy storage resources, leading edge substation and distribution automation and control, energy management interfaces, and innovative customer programs to include time of use (TOU) rate structures. The Project will focus on the area served by KCP&L's Midtown Substation across 2 square miles, impacting about 14,000 commercial and residential customers across ten circuits with total electric demand of 69.5 Mega Volt Amperes (MVA). The Smart Grid Project includes over 25 stakeholder groups including: Mid-America Regional Council (MARC), Missouri Electric Cooperative (MEC), Missouri Gas Energy (MGE), University of Missouri at Kansas City (UMKC), the Missouri Public Service Commission, The Kansas Corporation Commission, City of Kansas City, Missouri and several local neighborhood groups.[69]

Within the Smart Grid Project boundaries lies the Green Impact Zone project, a 150 square block area of inner-city neighborhoods in Kansas City. The primary goal of the Green Impact Zone Project is to transform distressed urban neighborhoods into a sustainable community.[70]

The Project will be based upon the guidance found in the proposed National Institute of Standards (NIST) interim Smart Grid Interoperability Standards Roadmap, the EPRI IntelliGrid Architecture and the GridWise Architectural Council recommendations.[71]

The primary, overall focus for the Project will be to implement next-generation, end-to-end Smart Grid components that will include Distributed Energy Resources (DER), enhanced customer facing technologies, and a distributed-hierarchical grid control system that includes the following key elements:[72]

- Upgrade the Midtown Substation to create a next generation "Smart Substation;" with multiple distribution circuits that have a variety of feeder-based instrumentation and control devices for monitoring and control, and a Grid management infrastructure to support the upgraded grid, back office and substation requirements (see detailed description below);

[69] Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.
[70] KCP&L Green Impact Zone Smart Grid Demonstration Abstract.
[71] KCP&L Green Impact Zone Smart Grid Demonstration submitted to the DOE, August 26, 2009.
[72] KCP&L Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009.

- Smart Meters (14,000) with AMI installed at all customer sites to provide consumers with enhanced information on energy use and the opportunity to utilize residential TOU rate structures.
- Integration of distributed generation that includes an Exergonix 1 MW Superior Lithium battery storage system that was delivered and installed at the Midtown Substation in April 2013;
- Distributed roof-top solar photovoltaic systems that include installations at Paseo High School, Blue Hills Community Center, UMKC Student Union and Flarsheim Hall, and Midwest Research Institute;[73]
- Distributed electrical vehicle charging stations. Currently the Company has 20 charging stations at various locations and is monitoring usage patterns. The Company may install additional charging stations depending upon future market developments, and;
- Demonstration House (Project Living Proof) that is located at 917 Emanuel Cleaver II Blvd and is open to the public. KCP&L has partnered with the Metropolitan Energy Center to show case products and technology applications that include smart washers and dryers, smart water heaters, roof top solar, battery storage and associated DC to AC inverter, alternative heating and cooling equipment, an electrical vehicle charging station, sustainable landscaping, energy efficiency measures, and devices and web based tools utilized by customers in the Smart Grid demonstration project as described below.

Consumers within the Smart Grid demonstration project boundaries will be offered a wide range of products and services with the following expected level of participation[74]:

- Customer's with internet will have access to real-time energy usage by viewing a personalized web page via a web portal ("MySmart Portal");
- 1,600 residential and commercial customers are expected to have in home/business energy displays ("MySmart Display") that indicate real-time information and demand response thermostats ("MySmart Thermostat");
- 400 residential users are expected to utilize an Energy Management System (EMS);

[73] http://www.kcplsmartgrid.com/about-kcpl-smartgrid/solar-installation.
[74] http://www.burnsmcd.com/benchmark/Article/In-the-Heart-of-America-Smart-Grid-Demonstration

- 2 commercial users are expected to utilize an EMS;
- 10 LED area street lights will be installed at UMKC;
- 64 residential users are expected to utilize hyper-efficient appliances;
- 5 commercial and 10 residential users are expected to utilize roof-top solar; and
- 20 distributed vehicle charging stations will accommodate Plug in Hybrid Electrical Vehicles (PHEV).

KCP&L is in the final phase of this demonstration project that includes activities such as data collection, reporting and project conclusion, operating the integrated Smart Grid demonstration systems, collecting 24 months of grid data, evaluating systems and analyzing performance. KCP&L has completed the Smart Grid Demo home preparation, Smart Meter Acceptance test and the Home Energy Portal. The Smart Meter deployment with enhanced security implementation is complete.

Midtown Substation[75]

The Midtown Substation is located at 47th and Forest and is one of the oldest substations, built in the early 1960s. The new substation upgrades replace the existing substation controls and monitoring and older communication protocols. The upgraded Substation includes many upgrades for controls, automation and monitoring as described below.

[75] https://www.kcpl.com/troost/051308_mtgSumm.pdf & http://tdworld.com/distribution/wired-success

Control and automation functionality includes:

- Control and Data Acquisition
- Voltage and VAR control
- Power Flow
- Fault location, isolation and service restoration

Monitoring is implemented for the following:

- Transformers
- Circuit Breakers
- Exergonix 1 MW Superior Lithium battery storage system.
- Cables
- Surge Arrestors
- Access and activity

IEC 61850 Communications

- At the core or heart of the substation upgrade is the implementation of an IEC 61850 (International Electrotechnical Commission) communication and control network protocol communicating on redundant Ethernet-based communication networks.
- There are four primary automation schemes being implemented to provide automatic load transfer upon transformer lockout, fast clearing of bus load upon a feeder breaker failure, backup overcurrent protection for the bus differential relay protection and communication between devices to identify distribution system events.

Redundant Ethernet Communications Network

- The substation is being retrofitted with redundant fiber optic LANs (Local Area Networks) using network equipment from two hardware vendors, Cisco and RuggedCom.
- The LANs are segmented for smart grid security and the NISTIR (National Institute for Standards Interagency) 7628 standards to maintain secure communications within the EMS (Energy Management System) to meet NERC requirements for a critical infrastructure protection system critical asset.

Distribution Management System (DMS) & Distributed Energy Resource Management (DERM)

- These systems provide centralized oversight of the smart grid operations and perform economic evaluations for Demand Response (DR) implementation.

Microprocessor-based Relaying

- The substation is deploying a number of SEL (Schweitzer Engineering Laboratories)[76] relays for feeder and transformer protection that are compatible with the IEC-61850 standard protocol.[77]

Transformer Insulating Oil Dissolved Gas Monitors

- This equipment provides real time monitoring of the temperature and the moisture and combustible gases that are dissolved in the insulating oil of the substation transformers. The detection of certain combustible gases and moisture provides an early warning system of an impending transformer internal fault that will destroy the transformer and cause significant collateral damage.

Automatic Voltage Regulation and Control

- Load tap changers on the substation transformers are automated to adjust system voltage from the automated substation control system.

Battery Energy Storage System (BESS) [78]

- An Exergonix[79] 1 MW Superior Lithium battery storage system[80] is installed at the substation. The storage system consists of the battery, inverter and control system that will be utilized to store energy during off-peak times and provide energy during peak power periods.

For Smart Grid Components outside the Substation on the Distribution System see the Appendix.

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[76] http://www.selinc.com/smartsolutions/

[77] http://www.burnsmcd.com/Resource_/PressRelease/2535/FileUpload/article-TDWorld-Wired-for-Success-Olson.pdf

[78] http://www.sustainablebusinessoregon.com/national/2011/02/exergonix-tests-1-mw-battery-in-kansas.html & http://www.prnewswire.com/news-releases/kcpl-exergonix-mriglobal-pilot-new-energy-storage-system-173916571.html

[79] http://www.exergonix.com/index.php

[80] http://www.exergonix.com/battery_energy_storage_systems.php

C. The Boeing Company Smart Grid Regional Demonstration Project[81]

The Boeing Company Smart Grid Regional Demonstration Project will demonstrate an advanced Smart Grid software technology with military-grade cyber security for improving regional transmission system planning and operation. Boeing was selected on November 9, 2009, to receive an $8.5 million DOE grant to lead one project team and is a sub-recipient on two others -- one led by Consolidated Edison of New York and one by Southern California Edison. The project includes PJM, Midwest Independent Transmission System Operator (MISO), and Public Service Electric and Gas Company (PSE&G), a diversified energy company in New Jersey, who collectively serve all or part of 21 states and more than 90 million people.

These projects are designed to achieve the following goals:

- increase grid reliability
- reduce system demands and costs
- increase energy efficiencies
- rapidly allocate energy when and where it is needed
- provide greater network security and flexibility to accommodate new energy technologies

D. White River Valley Electric Co-op[82]

White River Valley Electric Co-op has a full deployment of AMR meters throughout its service area. In 2008, it began a beta testing phase for Google PowerMeters utilizing the MultiSpeak® specification. This approach gives customers access to daily energy usage and allows customers to track energy usage constantly. This provides a way for customers to better understand energy usage throughout the home and to minimize that usage. Google retired its PowerMeter Program on September 16, 2011.[83] A similar home energy management software service provided by Microsoft called Hohm was terminated on

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[81] http://boeing.mediaroom.com/index.php?s=43&item=976 & http://www.boeing.com/news/frontiers/archive/2010/june/i_bds01.pdf
[82] http://www.whiteriver.org/default.aspx)
[83] http://www.google.com/powermeter/about/

May 31, 2012.[84] Both Google and Microsoft indicated that slow market adoption did not justify continued development.

E. Co-Mo Electric Cooperative[85]

Co-Mo Electric Cooperative has been fully deployed with AMI meters since 2002. The company uses multiple avenues to show customers their hourly and daily usage through the "Power ByThe Hour" program[86] that utilizes a Two-Way Automatic Communications System (TWACS) using the MultiSpeak® specification. The AMI meter deployment has allowed the company to move into prepay electricity accounts with its customers, which would not have been realistic prior to AMI deployment.

F. Laclede Electric Cooperative[87]

Laclede Electric Cooperative (Laclede) deployed a wireless advanced metering infrastructure (AMI) system in 2008, as its first step toward the development of a smart grid that will enhance customer service, improve overall electrical network efficiencies, reduce operating costs, and automate the way energy is monitored and managed.[88] Laclede selected a Tantalus Utility Network (TUNet) for flexibility, scalability, and capability to serve as a single communications backbone that supports the full range of smart grid functionality.[89]

The Smart Grid initiative includes a full change-out of approximately 36,000 existing electromechanical meters with Itron CENTRON® solid-state meters.[90] The new meters will monitor consumption and power quality, pinpoint outages by individual meter or in aggregate and integrate customer data into backend billing, load forecasting, and other applications.[91] Laclede also entered into a contract to provide Ft. Leonard Wood with commercial and industrial energy management services.[92]

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[84] http://en.wikipedia.org/wiki/Hohm
[85] http://www.co-mo.coop/usageinfo.aspx
[86] Ibid
[87] http://www.lacledeelectric.com/
[88] T-Net News, October 7, 2009.
[89] Tantalus Laclede Electric Case Study: http://tantalus.com/cs_laclede.php
[90] Presentation by Terry Rosenthal, Laclede Electric Engineering Manager at Tech Advantage 2010 Conference and Expo.
[91] Tantalus News Laclede Electric Press Release, November 4, 2008.
[92] T-Net News, October 7, 2009.

G. Black River Electric Cooperative (BREC)

Black River Electric Cooperative (BREC) was formed in 1938 to provide electricity to a service area that encompasses the southeast Missouri counties of Bollinger, Cape Girardeau, Dent, Iron, Madison, Perry, Reynolds, Shannon, St. Francois and Wayne.[93] BREC signed an agreement with Aclara Systems to install the TWACS advanced metering infrastructure solution in its service territory and implementations started in 2008. The Aclara TWACS systems uses power lines to transmit data to and from the smart meters installed at customer locations. The system makes it easy to use existing power lines to reach all customers, even those in remote locations. The technology provides a solid metering foundation and delivers valuable data for timely billing, load control, demand response, and outage detection and assessment. [94]

IX. MISSOURI INVESTOR-OWNED UTILITIES SMART GRID STATUS[95]

A. Ameren Missouri[96]

Smart Meters

Ameren Missouri has been 100 percent deployed with AMR since 2000 with 1.2 million meters in total, all owned by Ameren Missouri. There are approximately 100 'net metering' applications to date, 18,000 meters are configured for time-of-use/demand reporting and 5,000 are configured for 15-minute interval reporting for industrial and large commercial customer use. The remaining meters report daily kWhs for residential and small commercial customer use. In September 2009, Ameren Missouri conducted a study comparing the costs and benefits of AMR versus AMI and concluded the following:

- AMR achieves most of the operational benefits of AMI without the two-way communications – automatic 'reads,' outage notification; tamper detection, system load data.

[93] Smart Grid Information Clearing House; http://www.sgiclearinghouse.org/ProjectMap?q=node/2061
[94] Smart Grid Information Clearing House; http://www.sgiclearinghouse.org/ProjectMap?q=node/2061.
[95] Information for this section was provided by the individual IOU's through presentations, company websites and information provided during workshops and meetings with the MoPSC.
[96] http://www.ameren.com/sites/aue/Pages/home.aspx

- The operational benefits offered exclusively by AMI include remote connect/disconnect and remote meter programming/configuration.
- Conversion to AMI would require new meters, new communications infrastructure, a new operating system, and billing system integration with a total conversion estimated at over $300 million.
- As stated in the Ameren Missouri 2011 Integrated Resource Plan (IRP), the planning team assumed that the existing AMR technology will begin to be converted to AMI technology beginning in 2015 when the existing AMR system would be approximately 20 years old.
- The Company is currently upgrading and modernizing its AMR system with the deployment of new field equipment that will provide increased network capacity for adding additional meters and increased communication flexibility.[97]

New field equipment includes Concentrators and Collectors in addition to the existing Cell Masters[98] and Micro Cell Controllers ("MCC").[99] The Concentrator receives wireless radio broadcasts from the electric meters and then transmits digital information to the Collectors. The Collector receives the information from the Concentrators and then transmits bundled digital information in "packets" to a central operating system for processing. Currently there are three Collectors, 226 Concentrators, 90 Cell Masters and 8,155 MCCs in the Ameren Missouri's service territory. Additional Cell Masters and Micro Cell Controllers will be added as required to maintain the current MCC and AMR coverage areas.

Electric Vehicle and Plug-In Hybrid Electric Vehicles

The auto industry has already standardized 120V and 240V charging characteristics and the associated plug-in connectors (i.e. 'interfaces'). Ameren Missouri placed a plug-in hybrid (diesel fuel and electric powered) bucket truck in service in the St. Louis metropolitan area in 2011 as part of an Electric Power Research Institute (EPRI) demonstration project. Ameren Missouri is also participating on a Plug-In Readiness Task Force with St. Louis Clean Cities as a means of monitoring initial discussions on how to create a local market for new

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[97] Ameren's Smart Grid report dated February, 2012.

[98] A wireless high capacity router device that receives and collects wireless data from Micro Cell Controllers and then transmits this data via a leased line to the central operating system.

[99] A small pole mounted data collection device that receives wireless AMR data and transmits this data to a Cell Master.

plug-in hybrid electric vehicles. The Company has a Chevrolet Volt hybrid automobile that employees are testing and evaluating. An August 2009 technology study concluded that there would be no significant system effects or impacts anticipated on Ameren Missouri's service territory until PHEV penetration approached approximately 150,000 vehicles.[100]

Electric Grid

Ameren Missouri's investments are focused on the electric system grid to improve service reliability, operating efficiency, asset optimization, and a robust energy delivery infrastructure. Ameren Missouri has approximately 2,300 line capacitors that are automated via one-way radio communications and approximately 800 tap changing substation transformers that are automated to adjust system voltage from commands issued by Distribution Control Offices. System voltage reduction has proven to work and Ameren Missouri-documented cases over 15 years show 1.0-1.2 percent demand reductions after programmed calls for 2.5 percent voltage reductions. Significant future infrastructure investments are required to take full advantage of this system optimization feature and the 1980s era legacy system of line capacitor control will need to be replaced.

A new communications network infrastructure is required to support two-way communications with intelligent line devices like capacitors along with a new distribution management system platform. Ameren Missouri smart grid components on the electric grid are described in the Appendix.

Customer Electric Usage Information[101]

Customers can view daily usage, create a profile for their house and explore options for energy savings by utilizing the Ameren Energy Savings Toolkit on the Company's website.

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[100] Ameren Missouri Presentation; "The Smart Grid @ AmerenUE", May 18, 2010, item 84, EFIS File No. EW-2009-0292

[101] http://www.ameren.com/sites/aue/csc/Pages/EnergySavingsToolkit.aspx

B. KCP&L[102]

Smart Meters

AMR deployment consists of 500,000 one-way communications meters that are read daily and were deployed starting in 1995. KCP&L currently has an 'MPOWER' program for energy curtailment and real-time pricing programs for customers.

The Smart Grid Demonstration Project deploys approximately 14,000 AMI Smart Meters with two-way communications reads on 15-minute intervals, utilizing a single field communications network for the infrastructure required for the project.

The 14,000 AMI Smart Meters replace existing AMR meters, but there will only be 1,600 energy displays and smart thermostats to utilize the additional information available through the AMI Smart Meters.

Electric Vehicles and Plug-in Hybrid Electric Vehicles

PHEV charging will be deployed as part of the Smart Grid Demonstration Project. With electric cars expected to soon hit the market, KCP&L plans to have 20 charging stations in place. The University of Missouri-Kansas City intends to install an electric charging station that will be available to the public. It will also be used to charge the university's first electric truck upon purchase. KCP&L has hybrid electric/E85 fuel vehicles as part of a pilot program with Ford Motor Company.

Electric Grid

The KCP&L electric grid infrastructure focuses on the pursuit of service reliability, operating efficiency, asset optimization, and building a secure, robust energy delivery infrastructure. KCP&L utilizes line capacitors that are automated via one-way radio communications, and tap-changing substation transformers that are automated to reduce system voltage from remote commands. Within KCP&L's Smart Grid Demonstration Project, as discussed in Section VIII.B., the Smart Distribution project will include a smart substation with a Distribution Management System (DMS) and an IP/RF 2-way Field Area Network (FAN). The grid will also include distributed generation that will include Smart Generation consisting of residential/commercial rooftop solar and residential battery storage.

Customer Electric Energy Information[103]

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[102] http://www.kcpl.com/ and Section VIII.B on the KCP&L Smart Grid Demonstration Project

[103] http://www.kcplsave.com/residential/connections/default.html

Customers can view daily usage through home energy web portals, create a profile for their house and explore options for energy savings by utilizing the KCP&L Connections website. It should be noted that not all households have Internet access and there are no libraries in the Green Impact Zone to provide this access.

C. Empire District Electric [104]

Smart Meters

Currently only electro-mechanical meters are deployed. Smart meter deployment was attempted earlier but abandoned due to failures in the communications infrastructure deployment. In March 2010, Empire District Electric assembled a team to develop a pilot program that would research and test the available metering products and technologies for an advanced metering infrastructure system. The team determined it would need to visit with a number of manufacturers, vendors, and other utility companies. The team determined it was also necessary to identify the required interfaces and to define the corporate resources needed to ensure a successful pilot implementation.

The proposed pilot program will include residential, commercial, and industrial customers, which will cover single-phase and three-phase applications. It is anticipated that implementation will include two different communications technologies via two separate phases. The scale, location, and timeline are pending approval.

Electric Vehicles and Plug-in Hybrid Electric Vehicles

No current plans for charging stations to accommodate EV and PHEV vehicles.

Electric Grid

Empire District Electric grid infrastructure focuses on service reliability, operating efficiency, asset optimization, and building a secure, robust energy delivery infrastructure. New substation relays and automated recloser switch controls utilize digital communications. Almost all power transformers have automatic load tap changers and those that do not have line voltage regulation in the substation. Empire's smart grid components on the electric grid are described in the Appendix.

[104] Information for this section was provided by Empire District in response to Data Request 0213 in Rate Case ER-2012-0345, Empire's presentations in workshops and meetings with the Staff and : https://www.empiredistrict.com/

Customer Electric Energy Information[105]

Customers can view daily usage through home energy web portals, create a profile for their house and explore options for energy savings by utilizing the Empire District Electric website.

X. ISSUES REQUIRING FURTHER EMPHASIS BY MISSOURI STAKEHOLDERS

Planning

Defining project goals based upon stakeholder input is essential. Stakeholder and customer engagement that leads to some ownership of the project plan are key elements that must be obtained. The MoPSC has initiated several workshops and conferences to discuss the future of Smart Grid in Missouri. All known stakeholders, including the IOUs of Missouri, other government organizations, potential vendors, consumer advocates, and other stakeholders have been involved in the workshops. There are also multiple pilot projects by IOUs and municipals that will provide more information. The path forward will be determined to a large extent from the information obtained through these efforts.

Large Scale Implementation

For any task as large as updating the electric grid, implementation should evolve through the execution of an overall plan in a phased approach.

This step can be one of the hardest steps as efforts can fail for numerous reasons. It has been the experience of Staff that the IOUs are trying to implement Smart Grid technology in a piecemeal fashion. They are developing test markets to research the areas of concern. By closely studying the results of workgroups, conferences, and pilots in the state and across the nation, a phased implementation plan can be developed. Taking the time to plan all phases and steps is critical to reducing mistakes and to implementing a Smart Grid that is capable of handling the future energy needs.

Cost Recovery

IOUs will need some form of cost recovery in order to be incentivized to deploy Smart Grid technology. The deployment of Smart Grid will include many resources and if the

[105] https://www.empiredistrict.com/login.aspx

consumer does not realize the promised benefits, the Smart Grid system does not achieve the desired results.

The MoPSC and stakeholders must work closely together to ensure that the technology that is implemented is prudent and beneficial for the IOU and the consumer. Some state commissions have taken action on the cost recovery aspect.[106] These actions, and the results of these actions, should be taken into consideration as Missouri moves forward and cost recovery becomes a prominent issue. The MoPSC should consider opening a docket to address this issue specifically, as it is one of the most important to all stakeholders.

Cyber Security and Data Privacy

With the introduction of a two-way communications system, there is a great concern about security and data privacy. A safe and reliable network is paramount for consumer confidence and the acceptance of Smart Grid. Although this issue is currently in the news and on the minds of many consumers, these issues have been addressed in several industries that include financial, defense, telecommunications, broadband wireless, Internet, Internet commerce, medical, etc. ... In a Privacy by Design report[107] entitled: "Achieving the Gold Standard in Data Protection for the Smart Grid," the following "Best Practices" are promoted:

1. Smart Grid systems should feature privacy principles in their overall project governance framework and proactively embed privacy requirements into their designs in order to prevent privacy-invasive events from occurring;
2. Smart Grid systems must ensure that privacy is the default – the 'no action required' mode of protecting one's privacy;
3. Smart Grid systems must make privacy a core functionality in the design and architecture of Smart Grid systems and practices;
4. Smart Grid systems must avoid any unnecessary trade-offs between privacy and legitimate objectives of Smart Grid projects;
5. Smart Grid systems must build in privacy end to end, throughout the entire life cycle of any personal information collected;

[106] The New York Public Service Commission in Case 09-M-0074 issued on April 14, 2009, a proposed framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure to provide a generic approach for guidance to the utilities. The Commissions in California, Texas and Vermont have provided similar guidance.

[107] Privacy by Design report entitled: "Achieving the Gold Standard in Data Protection for the Smart Grid", June 2010; http://www.privacybydesign.ca/content/uploads/2010/03/achieve-goldstnd.pdf

6. Smart Grid systems must be visible and transparent to consumers to ensure that new Smart Grid systems operate according to stated objectives;
7. Smart Grid systems must be designed with respect for consumer privacy as a core foundational requirement.[108]

The US DOE published a report titled "Study of Security Attributes of Smart Grid Systems-Current Cyber Security Issues" in April 2009 that concludes that Smart Grid cyber security must be a coordinated and ongoing effort through the full development lifecycle of Smart Grid implementation.[109] The Missouri Public Service Commission published an article titled "Cybersecurity: Guarding Against Threats to Utilities" in its December 2012 edition of PSConnection.

President Obama issued an executive order on February 12, 2013, directing "the Director of the National Institute of Standards and Technology (NIST) to lead the development of a framework to reduce cyber risks to critical infrastructure (the "Cybersecurity Framework")." As outlined by the White House, "the Cybersecurity Framework shall include a set of standards, methodologies, procedures, and processes that align policy, business, and technological approaches to address cyber risks."[110]

Currently, NIST is developing Cyber Security Standards for Smart Grid applications and it will be beneficial for all IOUs to comply with approved NIST standards.

Customer Acceptance and Involvement

With Smart Grid deployment in different geographical locations throughout the country, there are various approaches to customer education and communication. A multiple-pronged approach that can be tailored to specific customer types has shown to be the most effective way to maximize customer involvement in energy savings through smart applications. Access to real-time information, daily, hourly, and possibly in smaller increments, in relevant formats, mail, email, Internet portals, cell phone messages, phone calls, in-home monitors, etc., will give the customers the tools necessary to be more aware of their usage levels.

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[108] Ibid.
[109] http://http://www.inl.gov/scada/publications/d/securing_the_smart_grid_current_issues.pdf
[110] http://sgip.org/nist-to-play-major-role-in-administrations-executive-order-on-improving-critical-infrastructure-cybersecurity/

Customer Savings and Benefits

Customer savings will be a natural by-product of having knowledge about usage and being empowered to control usage levels through a choice of options best suited for the individual customer.

Customer savings may also be directly linked to demographics, education and income levels. Based on the observation and research of Staff, more affluent and educated customers, and those who own their own home, are generally more likely to spend extra money for energy efficient and smart appliances to realize energy savings over time. Low income, elderly and those customers that rent will generally be less likely to be in a position to spend extra money on energy efficient appliances, but will be more interested in actions they can take that require minimal investment. Reaching out to customers and customizing the approach to the type of customer will be a key issue. Advertised customer benefits should be conservative and realistic. Energy savings benefits to consumers ranges between 4-12 percent based upon the type of customer feedback provided.[111]

Industry Standards

NIST, in partnership with DOE and more than 100 stakeholders, has developed 5 main areas of focus for industry standards as follows:

[111] Special Report Number E105, Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities by ACEEE on Advanced Metering, June, 2010.

- Transmission and Distribution
- Building to Grid
- Industry to Grid
- Home to Grid
- Business and Policy

What will smart meters look like? How will they operate? Will smart appliances and smart meters be interoperable? Will smart meters and appliances be transferrable and/or transportable? As shown by the questions above, standards must reach a certain threshold to assuage basic concerns before a Smart Grid deployment makes sense. Smart Grid infrastructure deployment for Missouri should conform to a common set of approved standards to assure compatibility and uniformity across the state. The expectation of seamless integration of new 'smart' technologies with legacy systems and devices cannot be achieved without great attention to the principal of interoperability. The NIST Framework and Roadmap for Smart Grid Interoperability Standards Release 2.0,[112] provides an overview of the status of standards development.

With proper planning and implementation, which includes standards, customer education programs, and installation and maintenance, research suggests there should be an increase in the reliability of the generation, transmission, and distribution of power to customers.

Distributed Generation through CHP deployment

The Industrial/Commercial/Institutional Boiler maximum achievable control technology (MACT) rule to limit emissions from new and existing boilers was finalized on March 21, 2011 and amended on December 20, 2012.

With nearly half of the US boiler population over 40 years old, a natural gas CHP with a net metering application is one option that could be analyzed as a boiler replacement strategy in lieu of emissions control system modifications.

Low interest and creative financing programs could be considered and implemented on a case-by-case basis, tailored for each specific application such that the initial capital cost of the CHP system could be equal to other boiler replacement options and have lower overall life cycle costs. The differential in cost between the CHP system and other boiler options

[112] http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf

could be funded through energy efficiency savings and sale of energy such that the economic breakeven point would occur before the system end of life.

Stakeholder Concerns

Stakeholders have several concerns with regard to Smart Grid implementation. Questions raised by stakeholders including the following:

- Data Privacy
    - Who owns the data? Who has access to the data? How will the data provided via Smart Meters be used? What consequences are there to unauthorized access to this data? How vulnerable is my personal data?
- Cyber Security
    - How safe or vulnerable is the Smart Grid to a cyber-attack? What are the potential consequences to a cyber-attack on the grid or in the home? Can someone access my Smart Meter data without my or the utility's knowledge?
- Cost Benefit
    - What is the rate of return and cost benefit for the Smart Grid infrastructure investment? Are projected consumer electrical energy savings realistic? Is the consumer paying the majority of the Smart Meter implementation costs while the utility realizes the majority of the benefits? Are consumers not on a Smart Grid paying for the implementation costs for those consumers that are on a Smart Grid?
- Impact on Electrical Rates
    - How will Smart Grid infrastructure investments impact electric rates? Can the Smart Grid be implemented such that the cost savings offset the implementation costs?
- Reliability Concerns
    - Will the additional Smart Grid infrastructure equipment, components and devices increase or decrease overall electric system reliability?
- Safety Concerns
    - What is the amount of radio frequency (RF) radiation that is emitted from AMI or smart meters? Will the RF radiation impact my health or make me sick?

- Equipment Ownership
  - Will the Smart Grid Infrastructure up to and including the Smart Meter be owned by the electric utility and the equipment inside the residence or business be owned by the consumer?
- Technology Obsolescence and Compatibility
  - What is the realistic life of the equipment? How will it get upgraded? Who pays for what? Will the Smart Grid Infrastructure support software technology upgrades without hardware replacement?
- Technology Standardization and Acceptance
  - If I move, will my appliances and equipment that I currently have in my home work in my new home with a new electric service provider? How complicated, sophisticated is the equipment that will be installed in my home? Can I just "set and forget" or will the new technology require me to monitor my electric usage and take action on a daily basis? How convenient is it to use? Can I control my appliances over the Internet? Can I use a Smart Phone application?
- Customer Service
  - If I have a problem, do I make one call or several to resolve my problem? Will I speak with my local electric service provider or be routed to an automated call processing center outside my area?

XI. RECOMMENDATIONS FOR REGULATORY INVOLVEMENT

To what extent should the MoPSC be involved in all aspects of the Smart Grid issue? As discussed above, regulatory involvement will be important in the development of all areas of Smart Grid. Staff recommends the MoPSC hold a Smart Grid workshop or technical conference periodically for information exchange, sharing of best practices and educational purposes. Issues for discussion should include such things as cost recovery, cyber security and industry standards. The MoPSC should consider opening a docket to address the cost recovery issue specifically, as it is one of the most important issues applicable to all stakeholders.

With proper planning and implementation, which includes standards, customer education programs, and installation and maintenance, research suggests there should be an increase in the reliability of the generation, transmission, and distribution of power to customers.

APPENDIX: IOU ELECTRIC SYSTEM SMART GRID COMPONENTS

A. Ameren Missouri[113]

Ameren Missouri states that it has focused investments to improve its electric system grid service reliability, operating efficiency, asset optimization, and the energy delivery infrastructure. Ameren Missouri has deployed both technology solutions on its system as follows.

- **Smart Line Capacitors**. Ameren Missouri has approximately 2,300 distribution line (less than 20kV) automated capacitors that account for approximately 50 percent of its distribution feeders and approximately 3 percent of its sub-transmission feeders (20kV to100kV). Ameren Missouri plans to upgrade the control scheme for all of these smart line capacitors by 2014.
- **Automatic Voltage Regulation and Control**. Ameren Missouri has deployed tap changing substation transformers on approximately 65 percent of its distribution substation units and approximately 73 percent of its sub-transmission (34kV to 69kV) units that are automated to adjust system voltage from commands issued by Distribution Control Offices. Documented cases over 15 years have shown system voltage reduction has worked, with a 1.0-1.2 percent demand reduction resulting from a 2.5 percent voltage reduction.
- **Microprocessor Relaying.** Ameren Missouri has 72 percent line terminals in transmission (over 100kV) substations, 31 percent line terminals in sub-transmission substations, 72 percent line terminals in transmission switchyards and 17 percent line terminals in distribution substations converted from electro-mechanical to digital relaying that provide improved operating performance and self-diagnostic checks. Future plans are to upgrade 12 line terminals and four 69kV network terminals annually for a goal of complete deployment by 2020.
- **Supervisory Control and Data Acquisition (SCADA).** These systems are deployed in all the switchyards and provide real-time outage notification for enhanced outage response performance, improved operating flexibility and to prevent overloads.

[113] Ameren's Smart Grid report dated February, 2012

- **Smart Line Switches.** These devices detect line disturbances and provide communication of events to system operations personnel, isolate faulted lines, and restore service via alternate paths. There are 250 switches automating 17 percent of the sub-transmission line feeders and 250 switches automating 4 percent of the distribution lines with annual additions based upon system needs.
- **Smart line capacitors.** Capacitor banks control or stabilize the system voltage by minimizing voltage drops and absorbing energy from a line spike. The banks provide voltage stability by switching in capacitor banks to provide reactive power when large inductive loads occur, such as when air conditioners, furnaces, dryers, and/or industrial equipment start. They are deployed on 3 percent of the subtransmission feeders. There are 2,300 capacitors automating 50 percent of the distribution lines with additions deployments based upon system needs.
- **Automatic Supply Line Transfer.** These systems detect supply line disturbances and automatically reconfigure distribution substation switching to restore power following an outage. Ameren Missouri currently has 51 percent of its distribution substations deployed with this technology and will add this capability to new and existing substations.
- **Outage Management System.** This system provides outage management services that includes collecting customer call data and creates and prioritizes work orders to optimize Ameren Missouri's response to outages by shortening the outage duration and improving efficiency.

New technology solutions include the following:

- **Transformer Insulating Oil Dissolved Gas Monitors.** This equipment provides real-time monitoring of the moisture and combustible gases that are dissolved in the insulating oil of generator step-up transformers (20kV to 138 or 345kV), large power, transmission substation, subtransmission substation, and distribution substation transformers. The detection of certain combustible gases and moisture provides an early warning system of an impending transformer internal fault that will destroy the transformer and cause significant collateral damage.

  Ameren Missouri has deployed this system on 25 percent of its Generator Step-Up transformers, 5 percent of its transmission substation autotransformers, 2 percent of its sub-transmission substation transformers and 1 percent of the distribution substation transformers and plans to continue deployment on the remaining transformers based upon periodic maintenance schedules.

- **High Voltage Bushing Monitors.** These are devices that are installed on each high voltage bushing of generator step-up transformers, transmission substation autotransformers,[114] and subtransmission and distribution substation transformers to monitor the insulating oil quality or integrity. These monitors detect small degradations in the insulating level of the bushing that if allowed to continue, would decrease the insulating capability of the bushing to the point of failure causing collateral damage to transformer. Ameren Missouri has currently deployed this system on 25 percent of its generator step-up transformers, 5 percent of its transmission substation autotransformers, 2 percent of its sub-transmission substations and 1 percent of its distribution substation transformers.

Ameren plans to continue deployment on new transformers and the remaining transformers based upon periodic maintenance schedules.

- **Fiber Optic Winding Temperature Sensor.** These devices monitor the condition of transformer and autotransformer cooling systems and allow more accurate loading to the actual operating capability of the transformer. The sensors are currently deployed on 1 of the 19 transmission substation autotransformers and 2 percent of the sub-transmission substation transformers with plans to deploy on all new and replacement autotransformer installations.
- **Comprehensive Analysis Monitor.** This equipment uses weather data and online transformer sensor inputs to calculate accurate dynamic transmission substation autotransformer ratings. This equipment will allow closer operating margins and more accurate determination of the autotransformer rating. The equipment is currently deployed on 1 of the 19 autotransformers with plans to deploy on all new and replacement autotransformer installations.
- **Multi-Function Transformer Temperature Monitor.** These monitors perform simulation of several autotransformer and transformer winding temperatures to allow

[114] An autotransformer utilizes one set of windings with multiple connection points to change voltage levels.

optimum cooling during high transformer loading and predict unstable temperature conditions. Currently deployed on 42 percent of the autotransformers in the transmission substations, 35 percent of the sub-transmission substations and 25 percent of the distribution substation units with plans to deploy on all new and replacement transformer installations.

- **Phase Measurement Units (PMUs).** These devices provide highly accurate voltage, current and frequency monitoring at strategic transmission points to provide wide area situational awareness to detect impending serious upset conditions and allow correction actions to be taken to mitigate the event. Currently deployed on 16 of 319 (5%) transmission substation and switchyard line terminals..
- **Faulted Circuit Indicators (FCI).** These devices provide information on subtransmission (20kV to 100kV) and distribution (under 20kV) line disturbances and communicate this information to system operators in near real time. There are 10 indicating sets on 5 of the 2,184 distribution line feeders and 40 indicating sets on 25 of the 501 sub-transmission line feeders with plans to deploy with smart line switches in the future.
- **Smart Line Regulators.** The devices monitor and regulate line voltage via remote control of the regulator's tap changing mechanism. These regulators are currently deployed on less than 1% of the distribution lines with additional deployment based upon system requirements.
- **Wide Area Networks (WAN).** A WAN is a high capacity communications backbone network that transports large quantities of smart field device data to the Company's control centers. Ameren Missouri currently has 50 percent of its substations and 25 percent of its switchyards deployed with this technology and will add this capability to new and existing substations that are being upgraded with the long term goal of 100 percent deployment.
- **Field Area Networks (FAN).** A FAN is a wireless communication network that collects transmitted data from smart field devices and relays this information via traditional radio/cellular based networks. There are nearly 400 intelligent sub-transmission line and 2,500 distribution line devices using this type of network with annual additions bases upon system needs.

- **Local Area Network (LAN).** These networks aggregate data and provide communications from smart field to the WAN. LANs are currently deployed in 2 percent of the sub-transmission substations and less than 1 percent of the distribution substations. Future LAN deployment will be based upon the electrical grid requirements.

B. Kansas City Power & Light (KCP&L)

The Smart Grid electrical infrastructure components on the electric system grid that are outside of the Midtown Substation include the following:

- **Faulted Circuit Indicators (FCI).** There are 48 devices providing information disturbances that communicate this information to system operators in near real time. There are 10 indicating sets on five of the 2,184 distribution line feeders (less than 1 percent) and 40 indicating sets on 25 of the 501 (5 percent) subtransmission line feeders with plans to deploy smart line switches in the future.
- **Smart Line Switches or Reclosers.** These devices detect line disturbances, provide communication of events to system operations personnel, isolate faulted lines, and restore service via alternate paths. There are 22 reclosers for automatic reconfiguration or load balancing.
- **Smart line capacitors.** Thirty capacitor banks control or stabilize the system voltage by minimizing voltage drops and absorbing energy from a line spike. The banks provide voltage stability by switching capacitor banks to provide reactive power when large inductive loads occur, such as when air conditioners, furnaces, dryers, and/or industrial equipment start.
- **Automated Metering Infrastructure (AMI).** Communications between all the devices utilize an AMI mesh network.

C. Empire

The Smart Grid electrical infrastructure components currently in operation or planned for the future (Smart Meters and Outage Management System upgrades) include the following:

- **Transformer Insulating Oil Dissolved Gas Monitors**. This equipment provides real time monitoring of the moisture and combustible gases that are dissolved in the insulating oil of three transmission (over 100 KV) autotransformers[115]. The detection of certain combustible gases and moisture provides an early warning system of an impending transformer internal fault that will destroy the transformer and cause significant collateral damage:
- **Smart line capacitors.** Capacitor banks control or stabilize the system voltage by minimizing voltage drops and absorbing energy from a line spike. The banks provide voltage stability by switching in capacitor banks to provide reactive power when large inductive loads occur, such as when air conditioners, furnaces, dryers, and/or industrial equipment start. These capacitors are automatically controlled by a microprocessor based program that actuates based upon time, temperature, voltage and reactive power inputs.
- **Smart Line Switches.** These devices are installed in Branson, MO, and detect line disturbances and provide communication of events to system operations personnel, isolate faulted lines, and restore service via alternate paths.
- **Faulted Circuit Indicators** These devices provide information on line disturbances and communicate this information to system operators in near real time for faster identification of problems and locating faulted circuits. These devices are currently installed where the three-phase supply service splits to serve two different loads.
- **Automatic Voltage Regulation and Control.** Automatic voltage regulation is installed at the majority of all distribution substations and consists of voltage regulators and/or transformer load tap changers.
- **Automatic Supply Line Transfer.** These systems are installed in Branson, MO to detect supply line disturbances and automatically reconfigure distribution substation switching to restore power following an outage.
- **Microprocessor Relaying.** For the past fifteen years, Empire has been changing from electro-mechanical to digital relaying that provides improved operating performance and self-diagnostic checks.

[115] An autotransformer utilizes one set of windings with multiple connection points to change voltage levels

- **Supervisory Control and Data Acquisition (SCADA).** These systems are deployed in the switchyards and provide real time outage notification for enhanced outage response performance, improve operating flexibility and prevent overloads. Open Systems International (OSI)[116] Energy Management System (EMS) system upgrades were completed in September of 2013.
- **Outage Management System (OMS).** This Intergraph InService Outage Management System[117] provides outage management services that include collecting customer call data and creates and prioritizes work orders to optimize the Company's response to outages by shortening the outage duration and improving efficiency. System upgrades, including the interface with the SCADA system, are scheduled for completion by the end of this year.
- **Wide Area Networks (WAN).** A WAN is a high capacity communications backbone network that transports large quantities of data to the Company's data centers, most service centers and customer service offices. Empire owns and operates its own fiber optic WAN.
- **Field Area Network (FAN).** A FAN is a wireless communication network. The OMS system utilizes a cellular wireless network for communication with Empire's service trucks.
- **Local Area Network (LAN).** This network aggregates data and interfaces with the WAN to provide internal company communications.

[116] http://www.osii.com/index.asp?nsgc
[117] http://www.intergraph.com/utilities/oms.aspx