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.
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Revision 6/10/13

June 10, 2013

Mr. Ryan Williams
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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

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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

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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	

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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

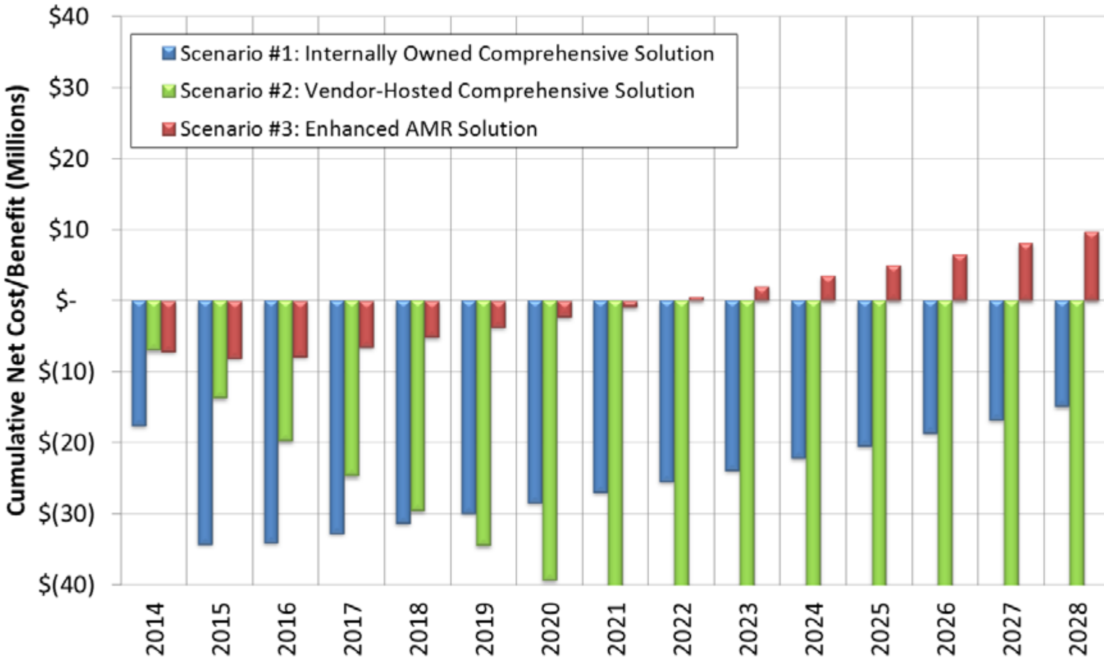


Figure 1.3: ROI Results of Direct Benefits to CWL without Conservation

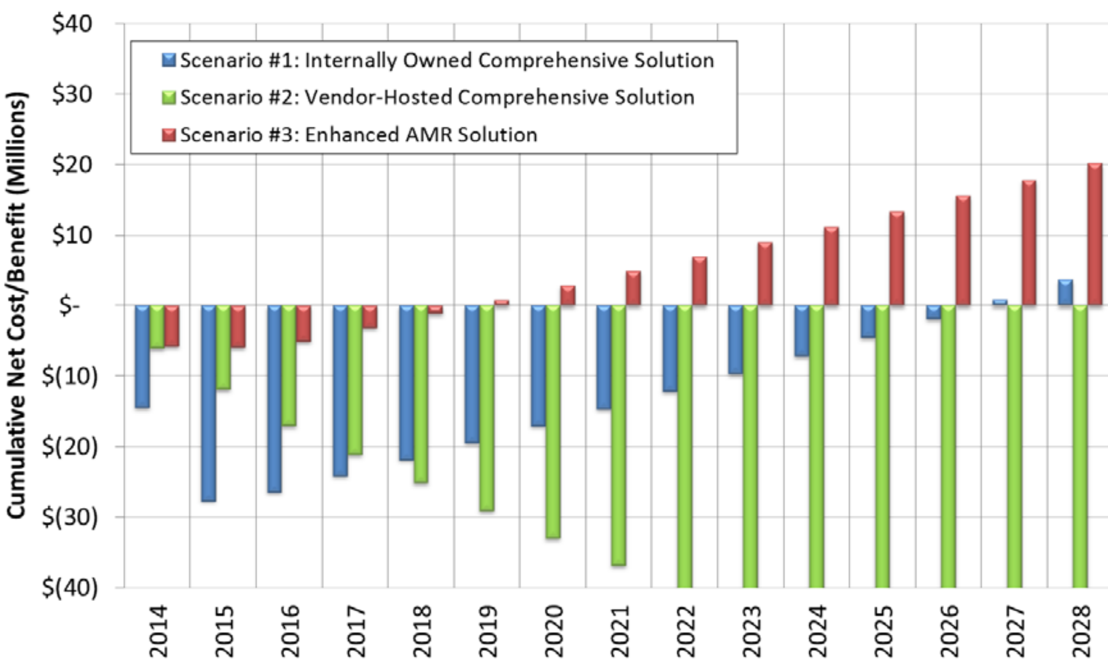


Figure 1.4: ROI Results of Benefits to CWL and Customers with Conservation

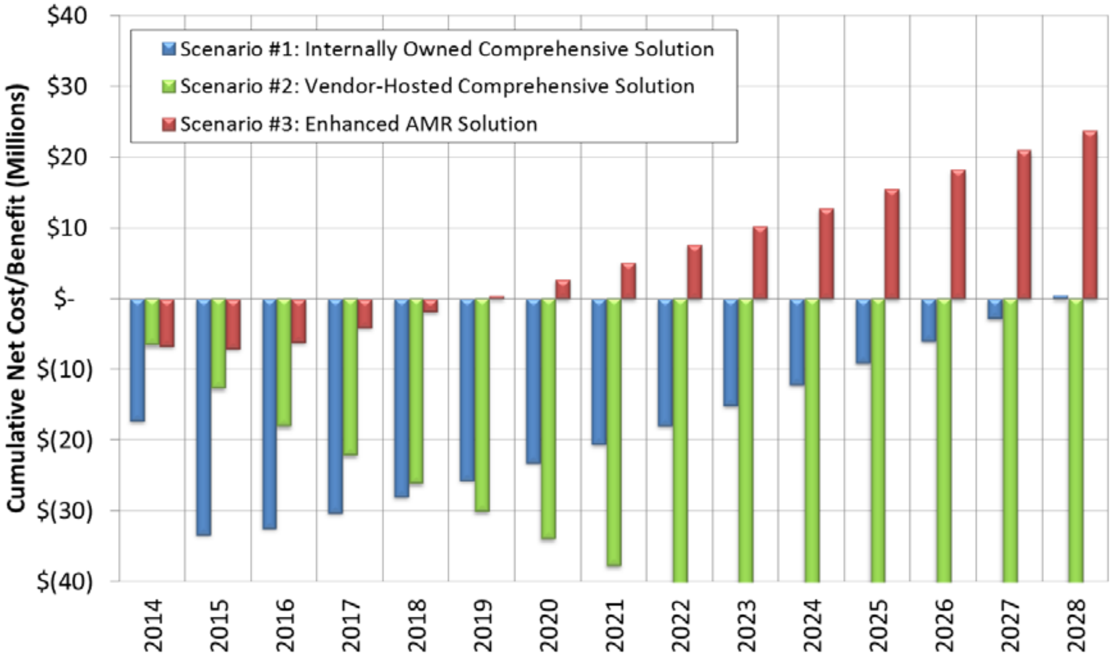
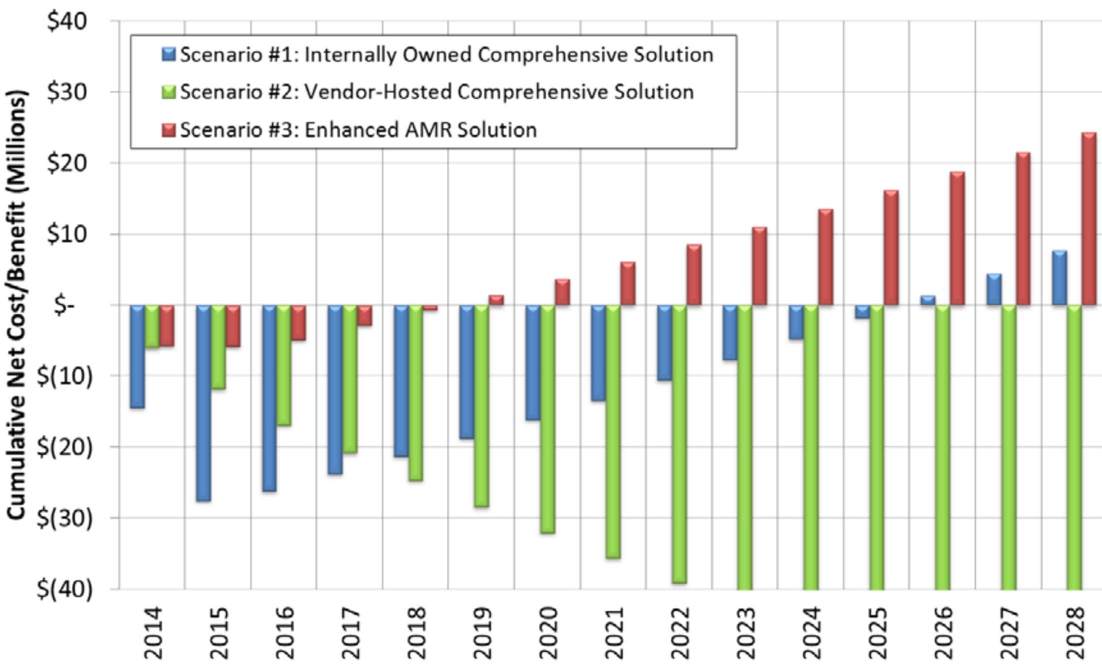


Figure 1.5: ROI Results of Benefits to CWL and Customers without Conservation



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.

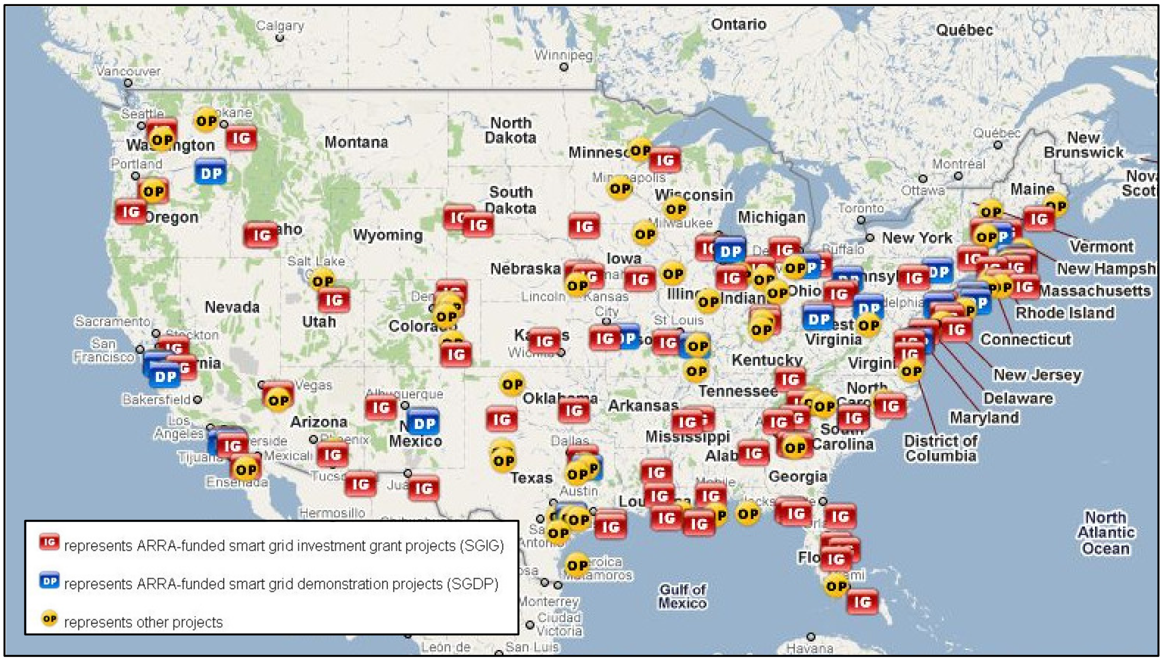
The utility embracing the advancement of their smart grid must realize that new technology will continue to be developed as the system matures. Using open architectures, industry standard communications, and flexible process implementation can allow the smart grid system to grow with new advances. Not 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.

* * * * *

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

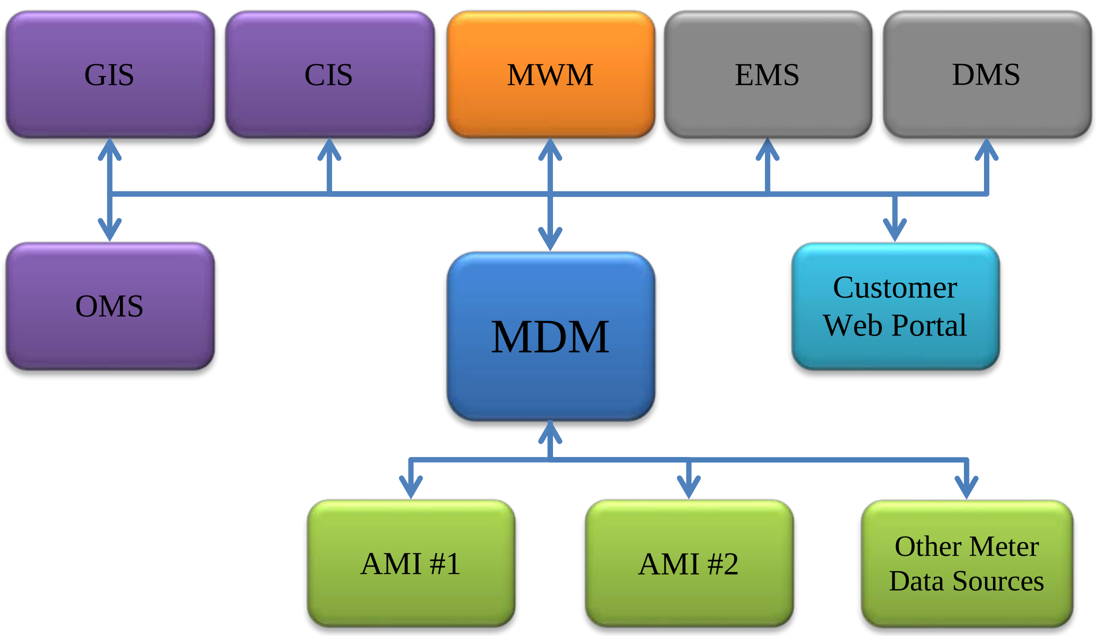
Smart grid technology deployments such as interval metering, distribution asset monitoring, and automation will produce significantly more data than utilities currently collect, manage, store and use. In order to make full utilization of these smart grid technologies, all relevant data should be readily 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

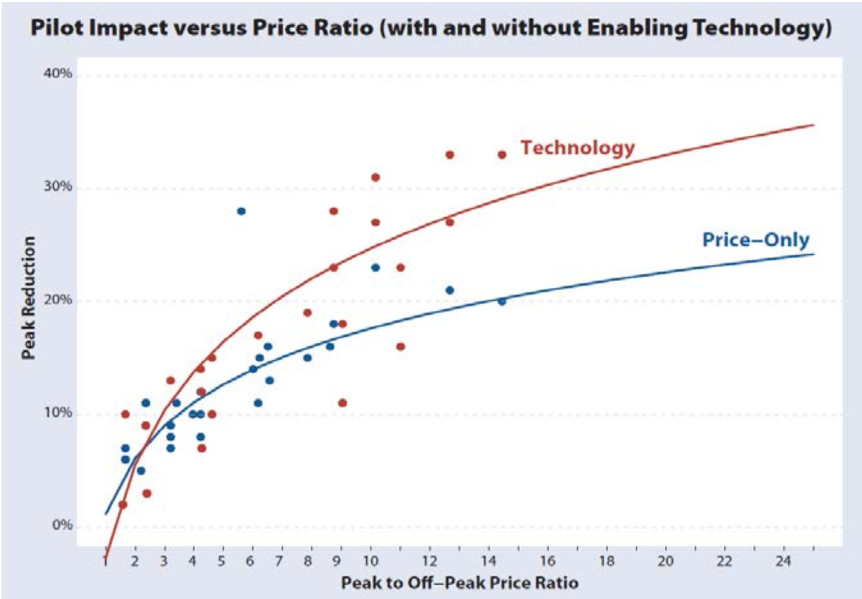
4.2.3 Time-Varying Rates – Demand Response

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.

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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.

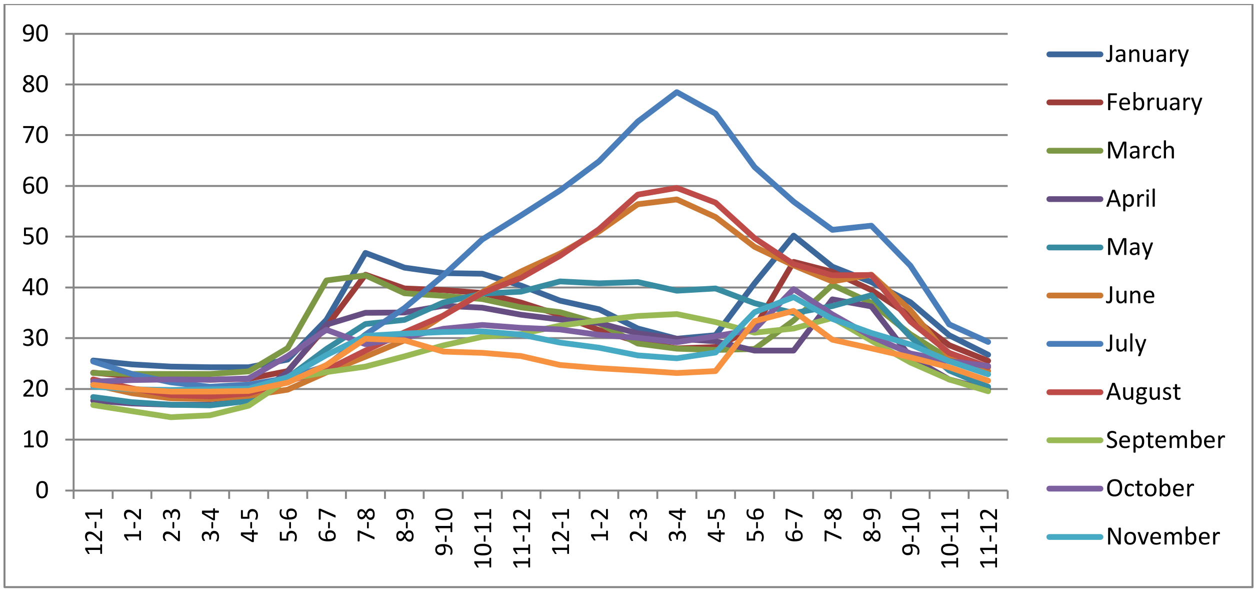
Remote monitoring and operation of distribution assets and devices will eliminate maintenance and outage truck rolls as well as enable more efficient restoration of device failures and other outages. This saves money on operations and reduces customer outage times, potentially increasing revenues.

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

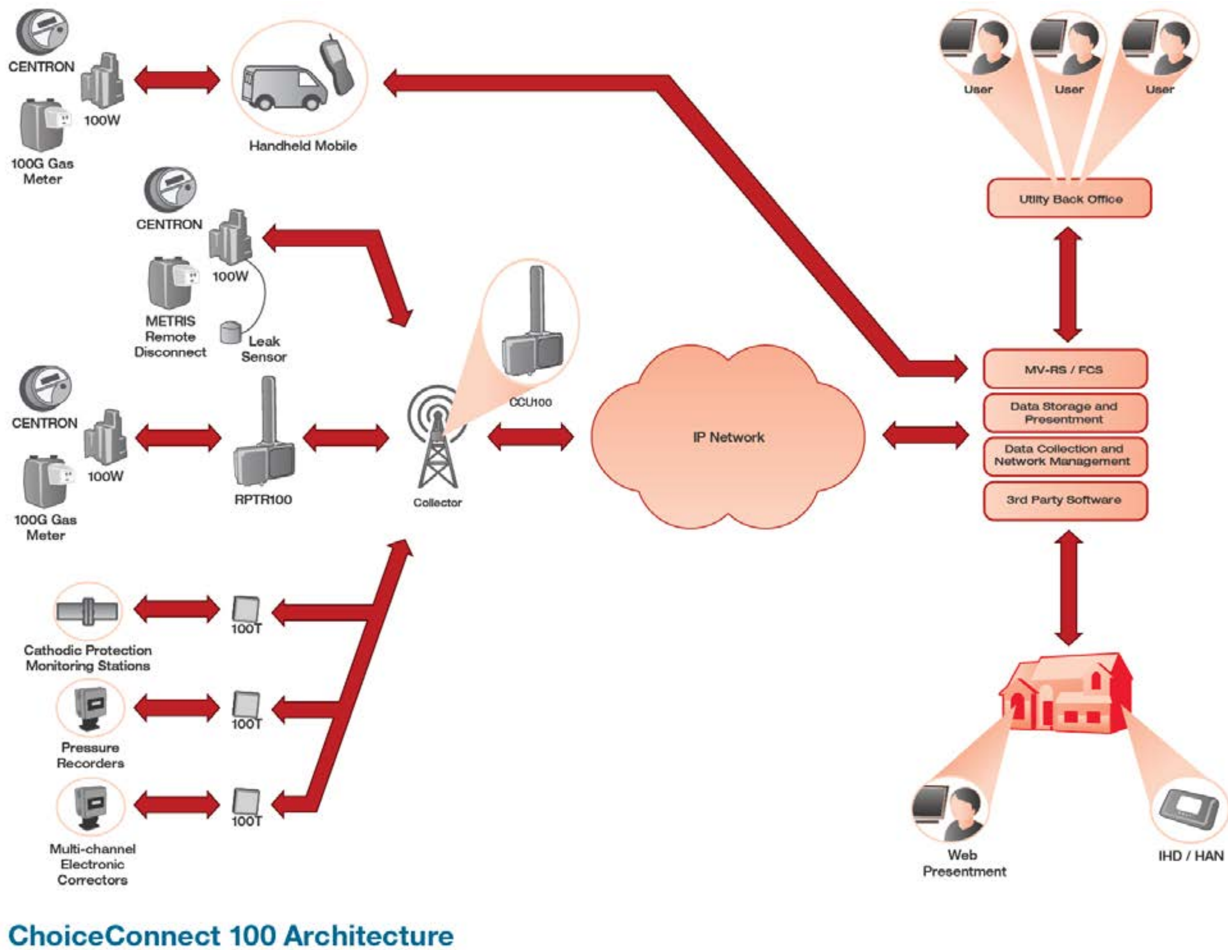
This approach would continue to utilize CWL's existing Itron digital meters with the addition of a compatible fixed network and MDM capable of capturing interval meter data. Distribution upgrades would be equivalent to the previous scenarios. This approach will limit capital investment in metering and 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



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

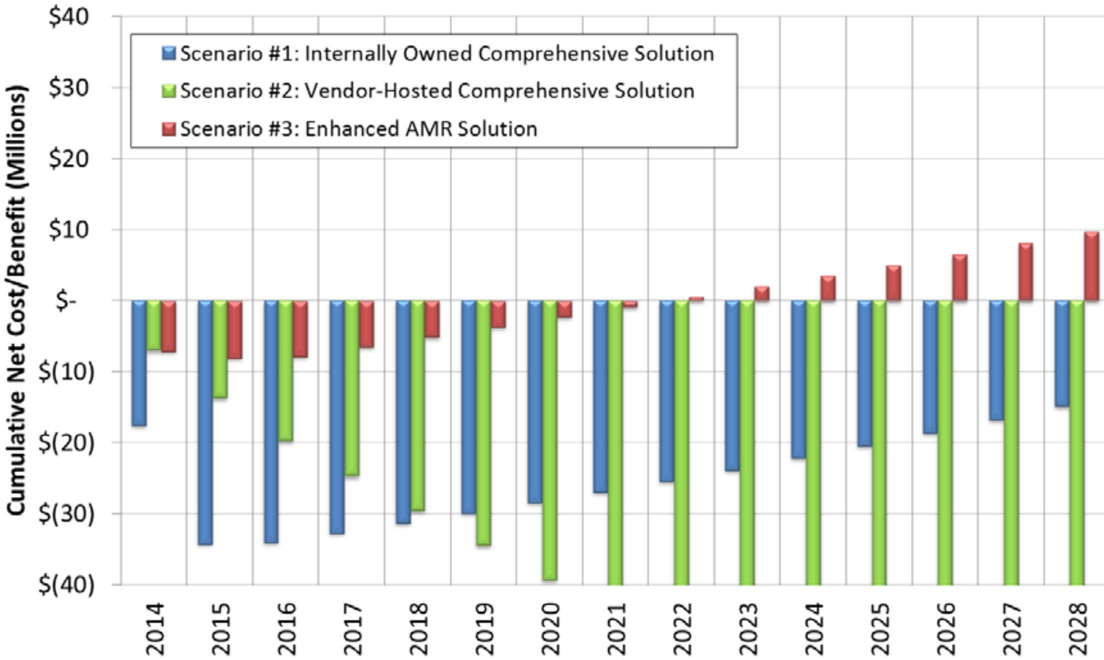
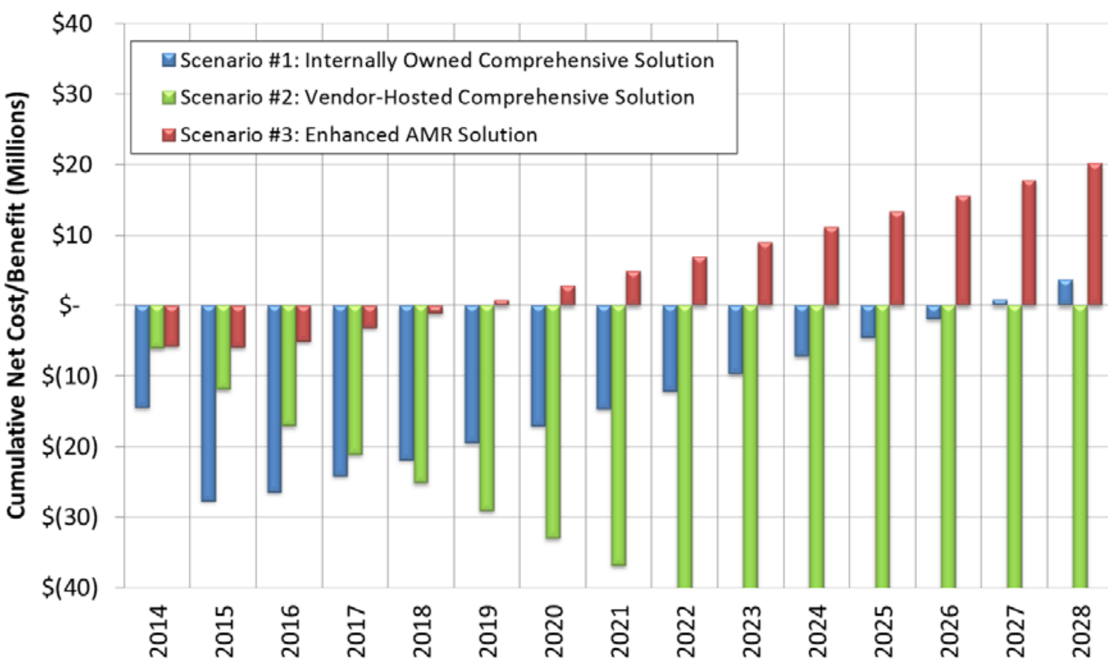


Figure 5.4: ROI Results of Direct Benefits to CWL without Conservation



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

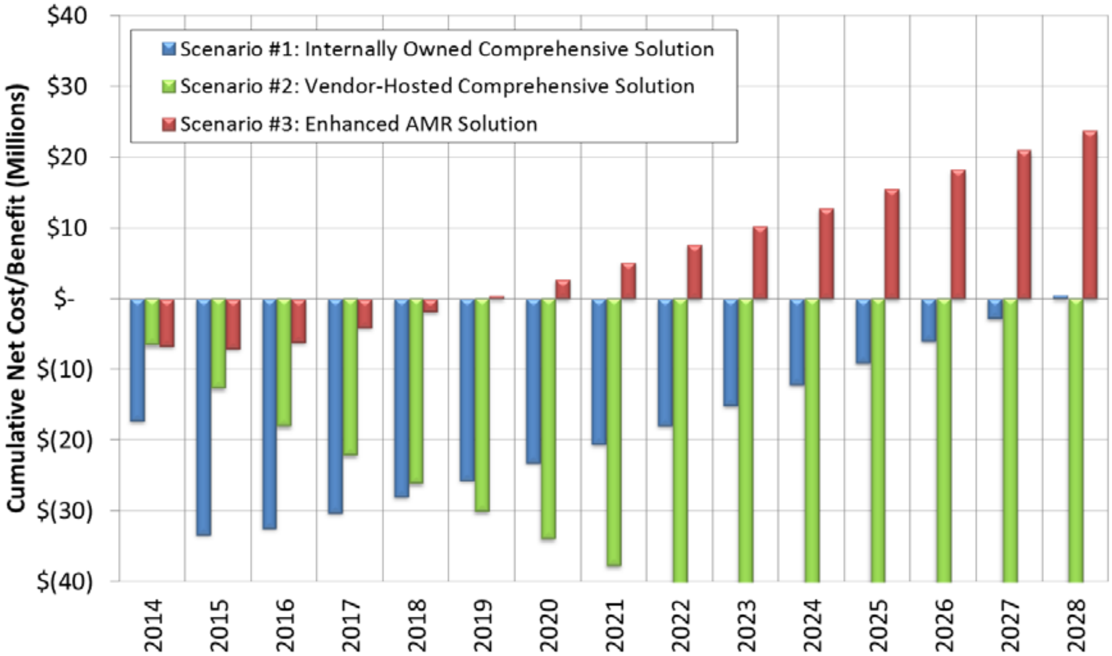
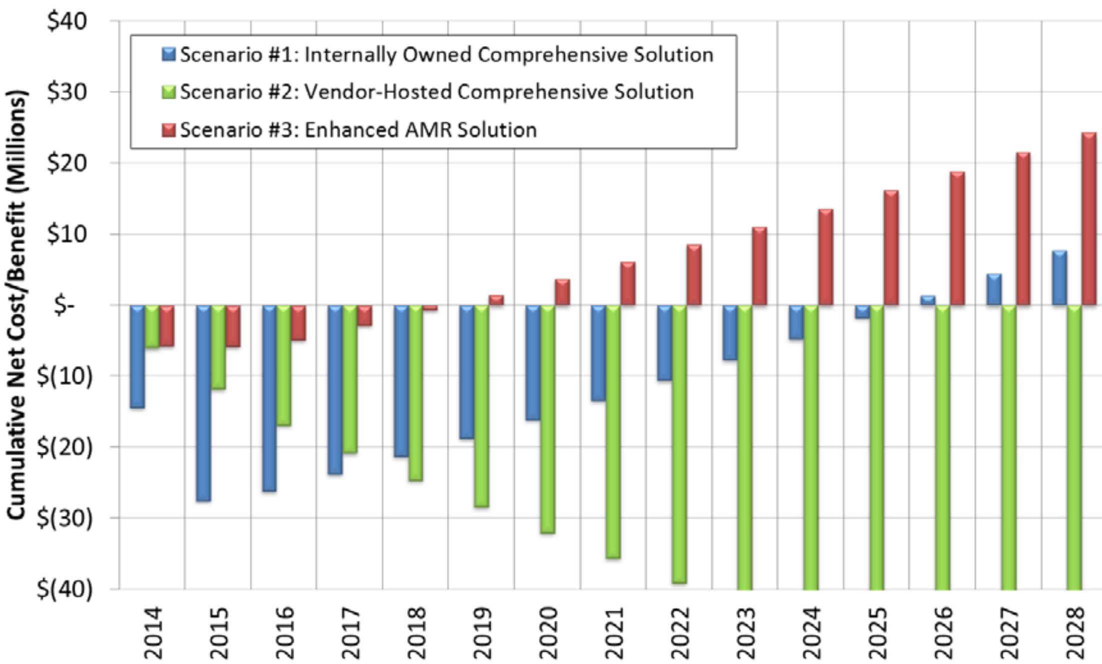


Figure 5.6: ROI Results of Benefits to CWL and Customers without Conservation



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.

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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.

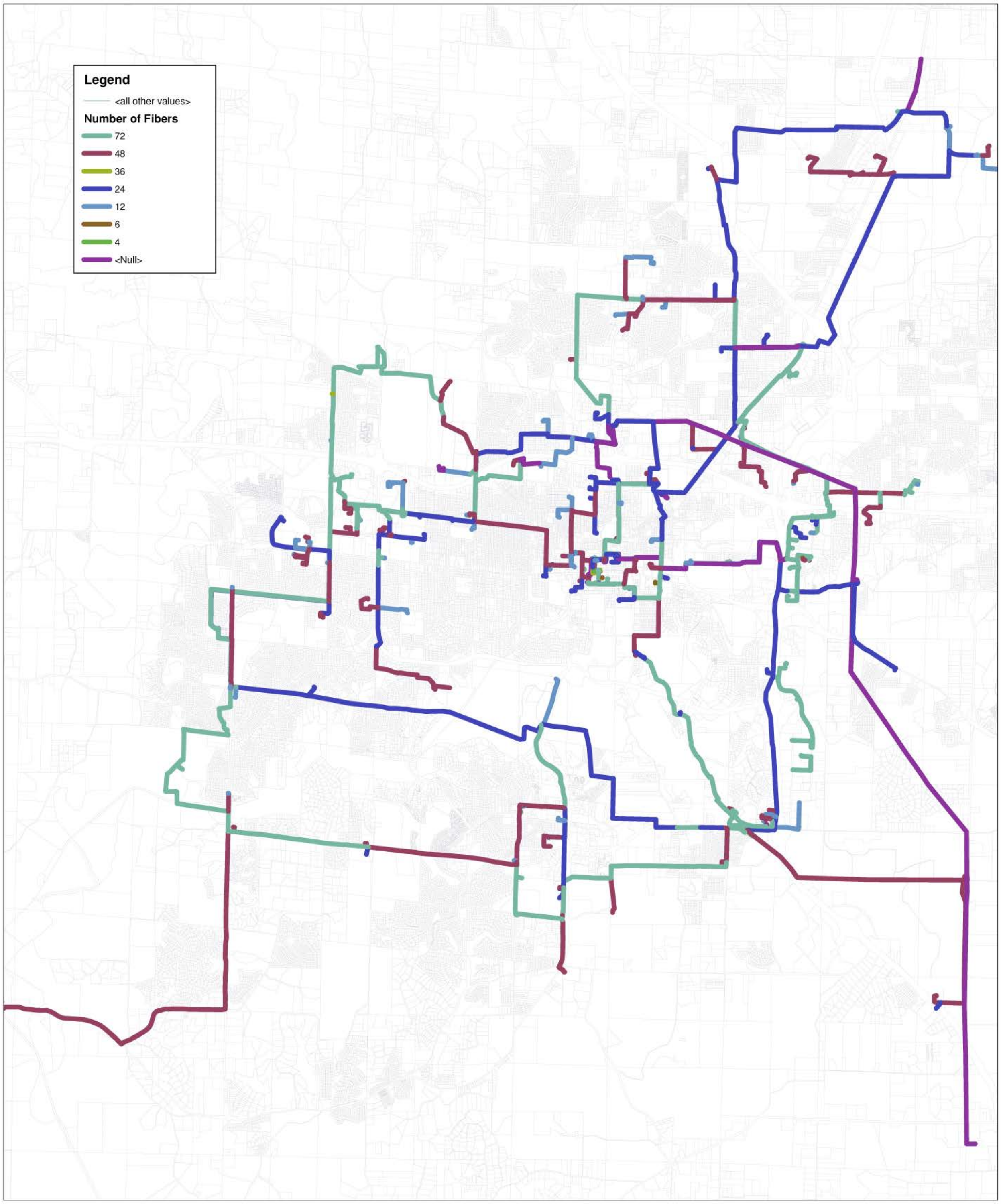
Project	Grant Award Amount	Total Project Value	Description
Midwest Independent Transmission System Operator	$17,271,728	$34,543,476	The Midwest Independent Transmission System Operator (Midwest ISO) is deploying synchrophasor technology throughout its service footprint. Midwest ISO's primary objective 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

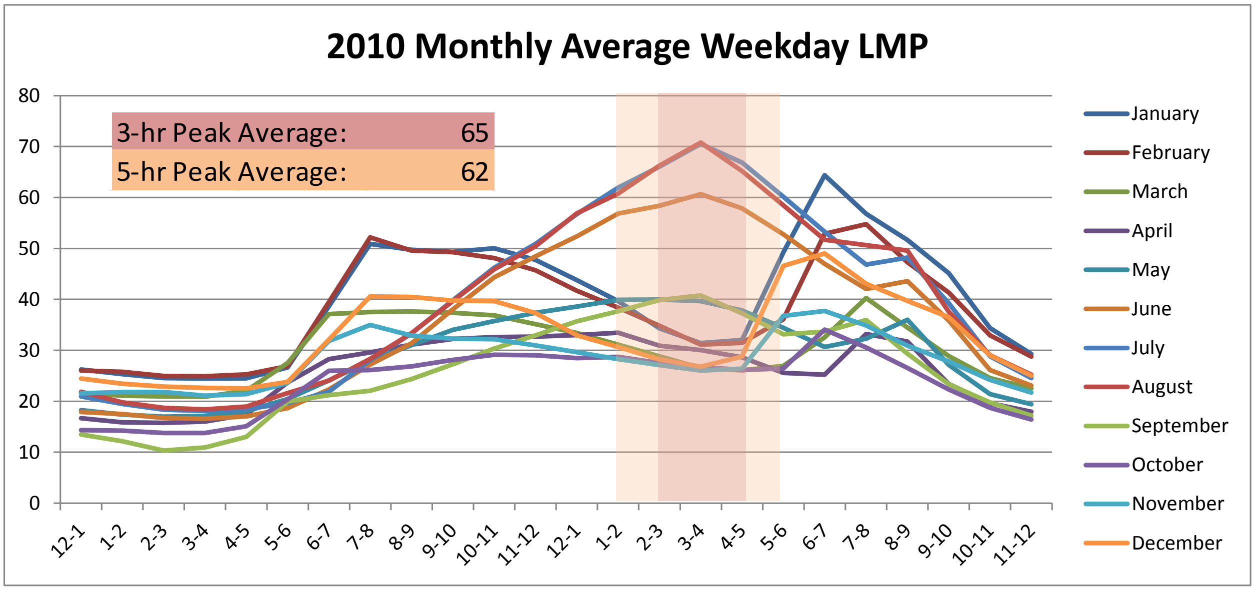
CWL's fiber network as of 2012:

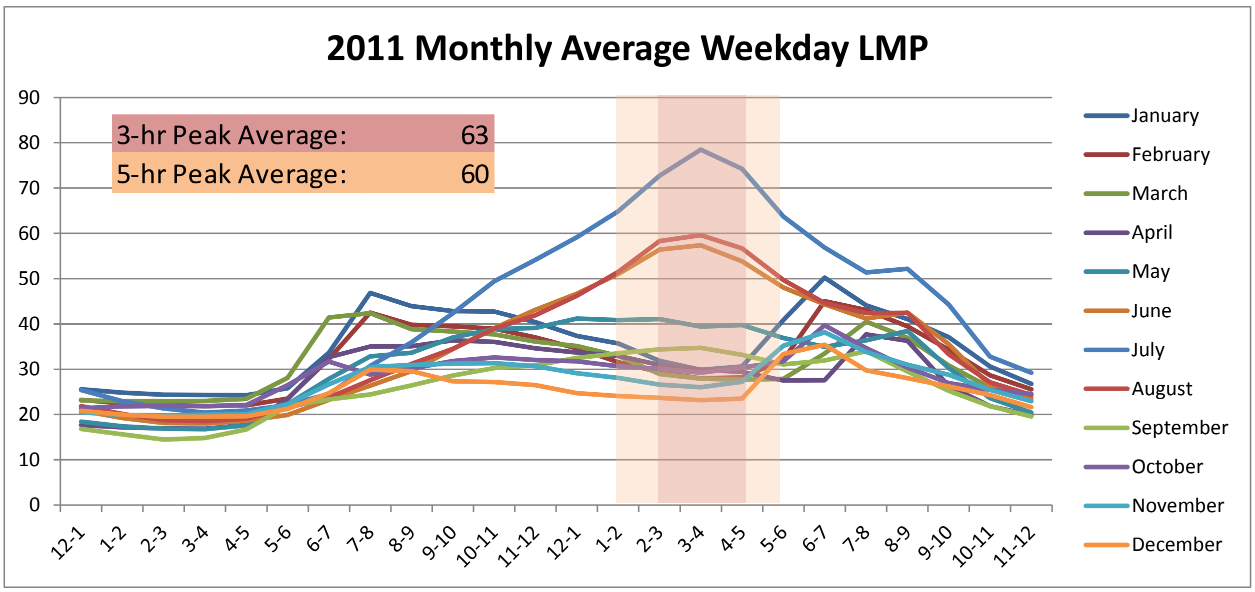


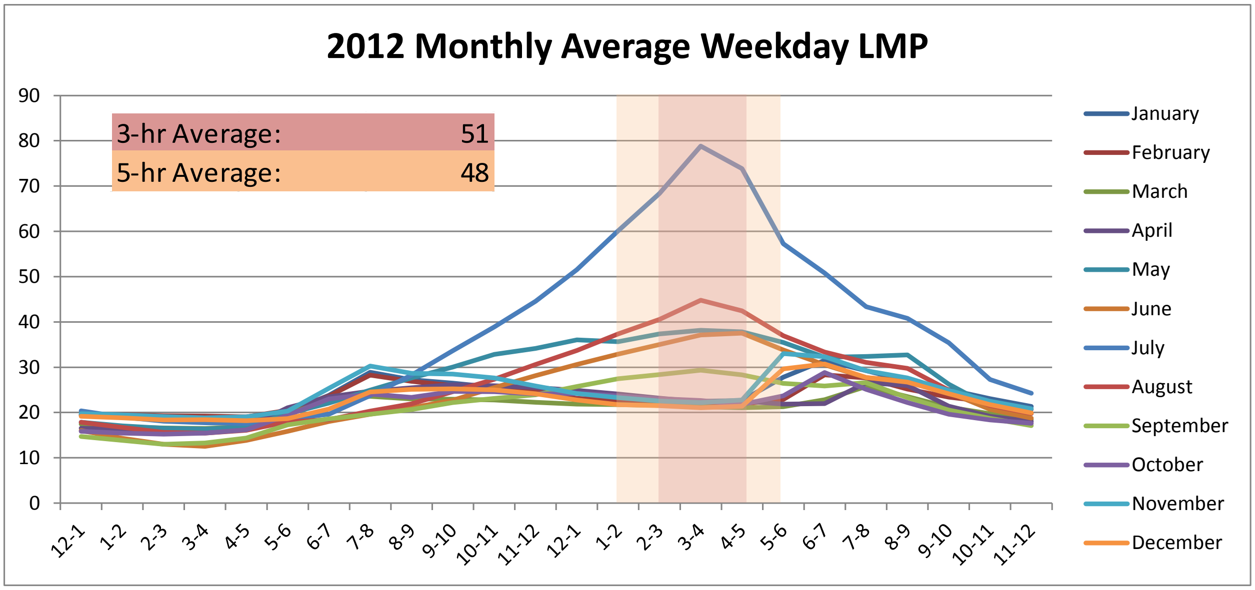
APPENDIX C

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
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January
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October
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**	**$ 751,803**	**$ 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**	**$ 35,174,745**
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 ($)	**-6.3%**
NPV (2013$)	**$ (20,674,048)**
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**	**$ 1,374,799**	**$ 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 1	$ 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**	**$ 1,621,531**	**$ 1,629,493**	**$ 1,637,455**	**$ 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 ($)	**7.5%**
NPV (2013$)	**$ 5,821,059**
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	**$ 8,395,786**	**$ 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**	**$ 7,395,118**	**$ 7,290,409**	**$ 7,329,844**	**$ 7,369,561**	**$ 7,409,565**	**$ 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**	**$ 2,148,675**	**$ 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)**	**$ (4,661,125)**	**$ (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 ($)	**#NUM!**
NPV (2013$)	**$ (57,575,315)**
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**	**$ 1,637,455**	**$ 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**	

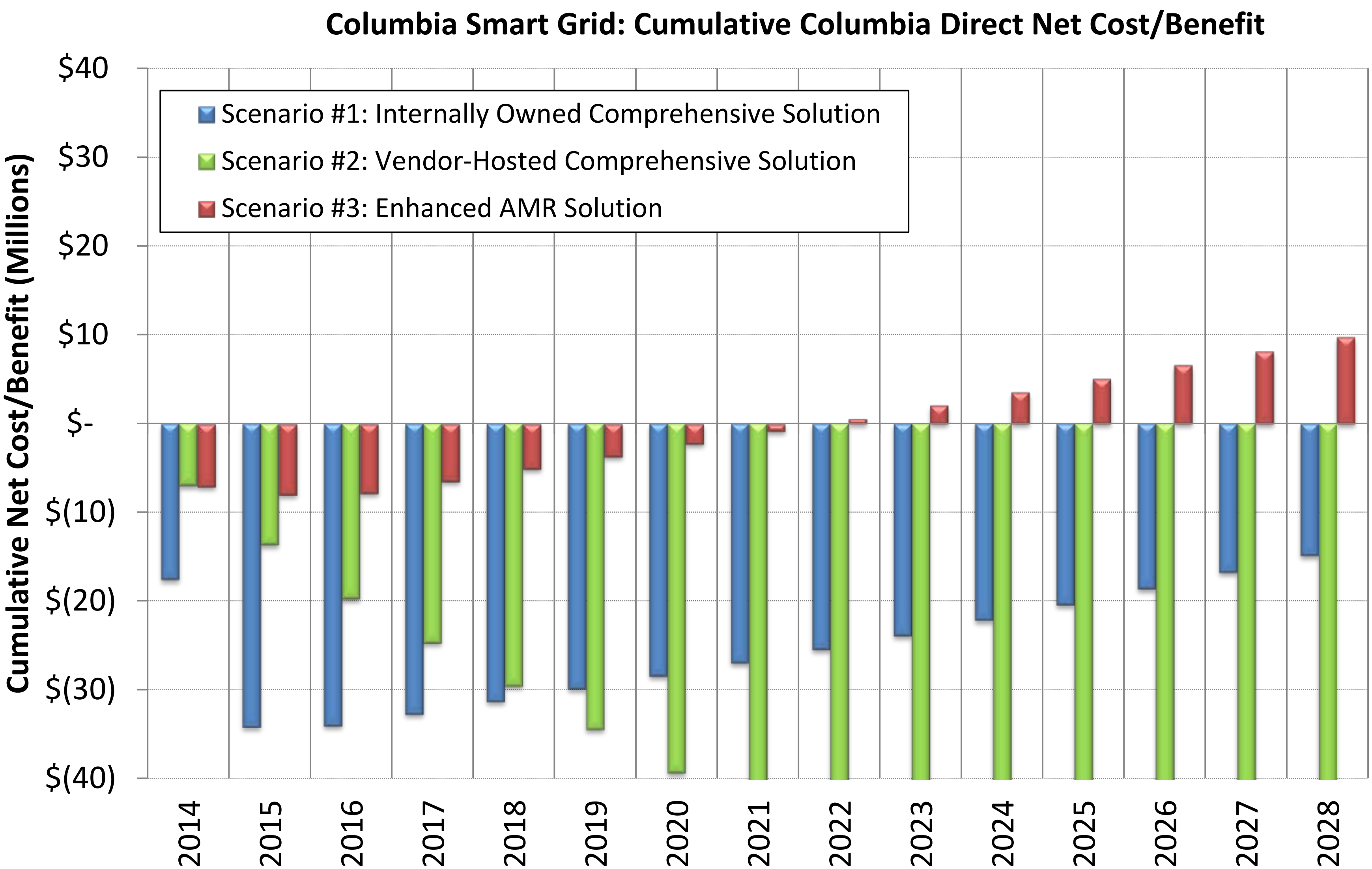
IRR ($)	**22.5%**
NPV (2013$)	**$ 13,531,588**
Simple Payback Period	**5.8 yrs**

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**	

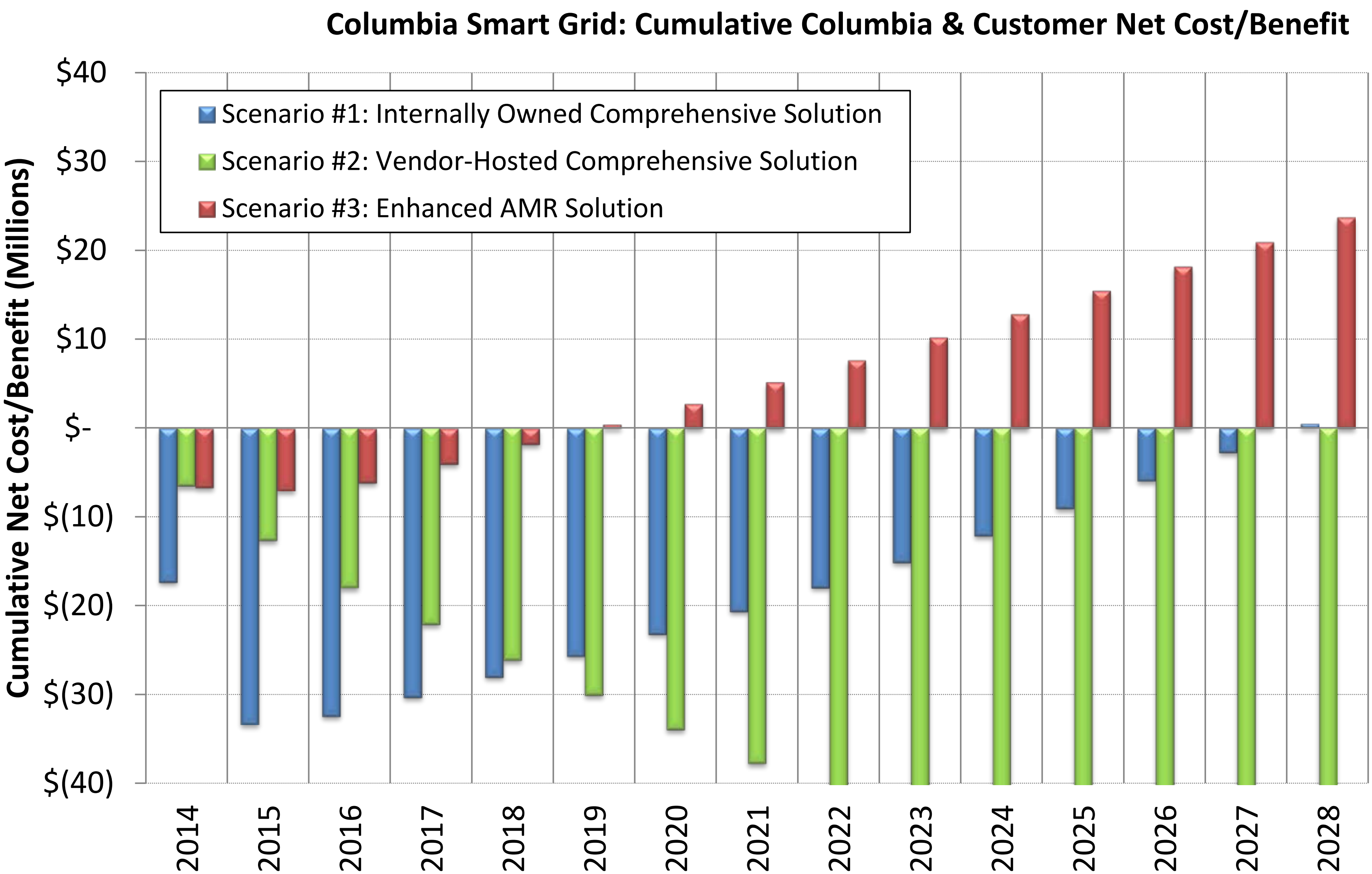
IRR ($)	**45.8%**
NPV (2013$)	**$ 29,888,359**
Simple Payback Period	**3.6 yrs**

Burns & McDonnell SINCE 1898

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	$ 20,019,388
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)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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**	**$ 2,525,305**	**$ 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)**	**$ (20,230,839)**	**$ (18,385,779)**	**$ (16,508,029)**	**$ (14,596,835)**	**$ (12,651,423)**	**$ (10,670,999)**	

year$	2013
discount rate	5.0%

IRR ($)	**-4.6%**
NPV (2013$)	**$ (17,305,843)**
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)**	**$ (22,755,193)**	**$ (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 1	$ 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**	**7,176,397**	**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**	**2,524,752**	**2,569,268**	**2,614,816**	**2,661,423**	**2,709,115**	**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)**	**(4,577,885)**	**(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 2	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**	**1,585,242**	**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

Burns & McDonnell SINCE 1898

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	**$ 1,125,283**	**$ 1,830,707**	**$ 2,032,874**	**$ 2,050,942**	**$ 2,068,713**	**$ 2,086,159**	**$ 2,103,255**	**$ 2,119,971**	**$ 2,136,235**	**$ 2,152,059**	**$ 2,186,433**	**$ 2,221,561**	**$ 2,257,461**	**$ 2,294,152**	**$ 2,331,654**	**$ 30,997,460**
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**

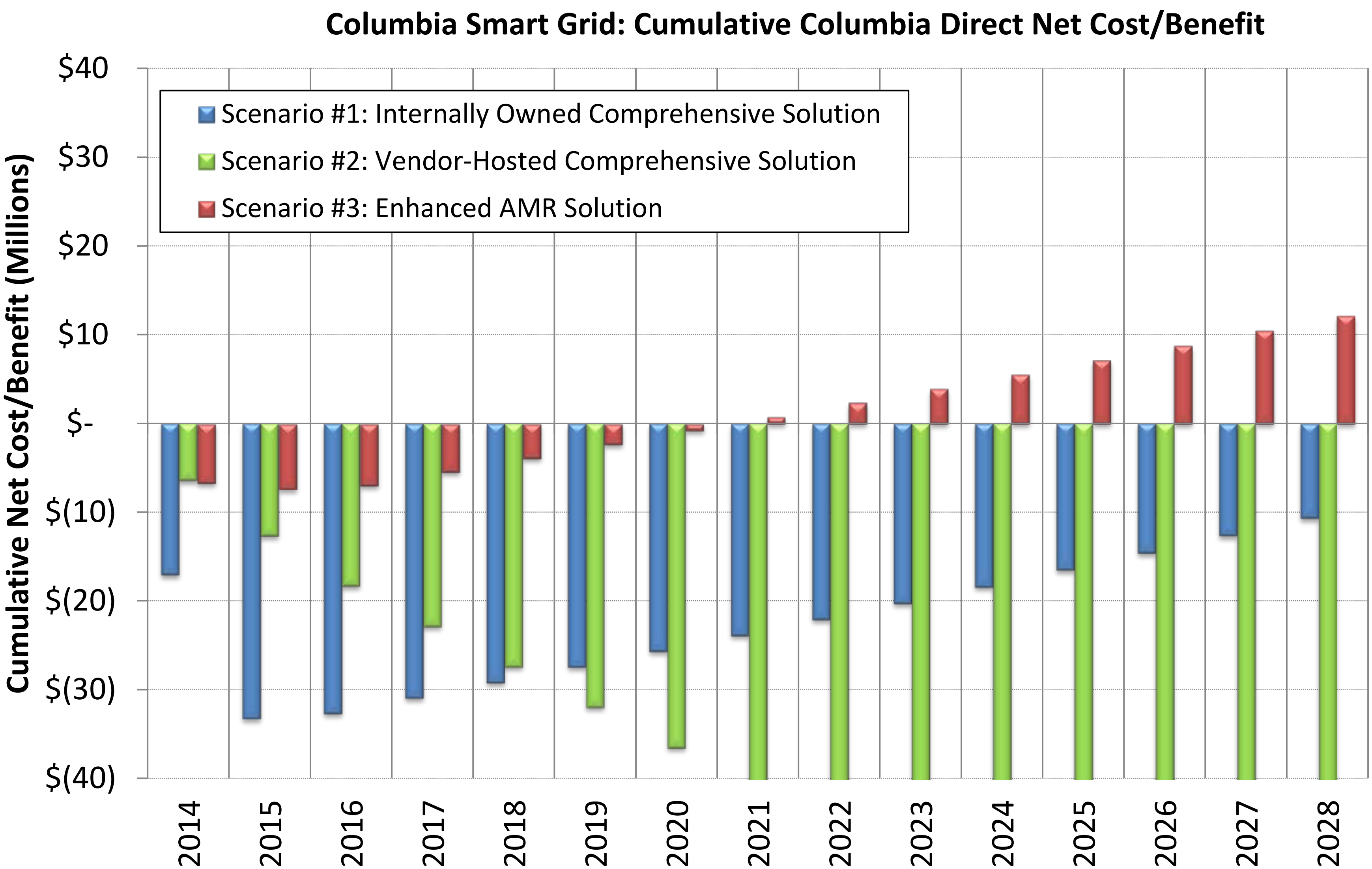
COLUMBIA CUSTOMER BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Energy Savings																
Customer Savings from Volt/VAR Optimization (Scenario 3)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Savings from Residential PCTs (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**	**$ 2,005,315**	**$ 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**

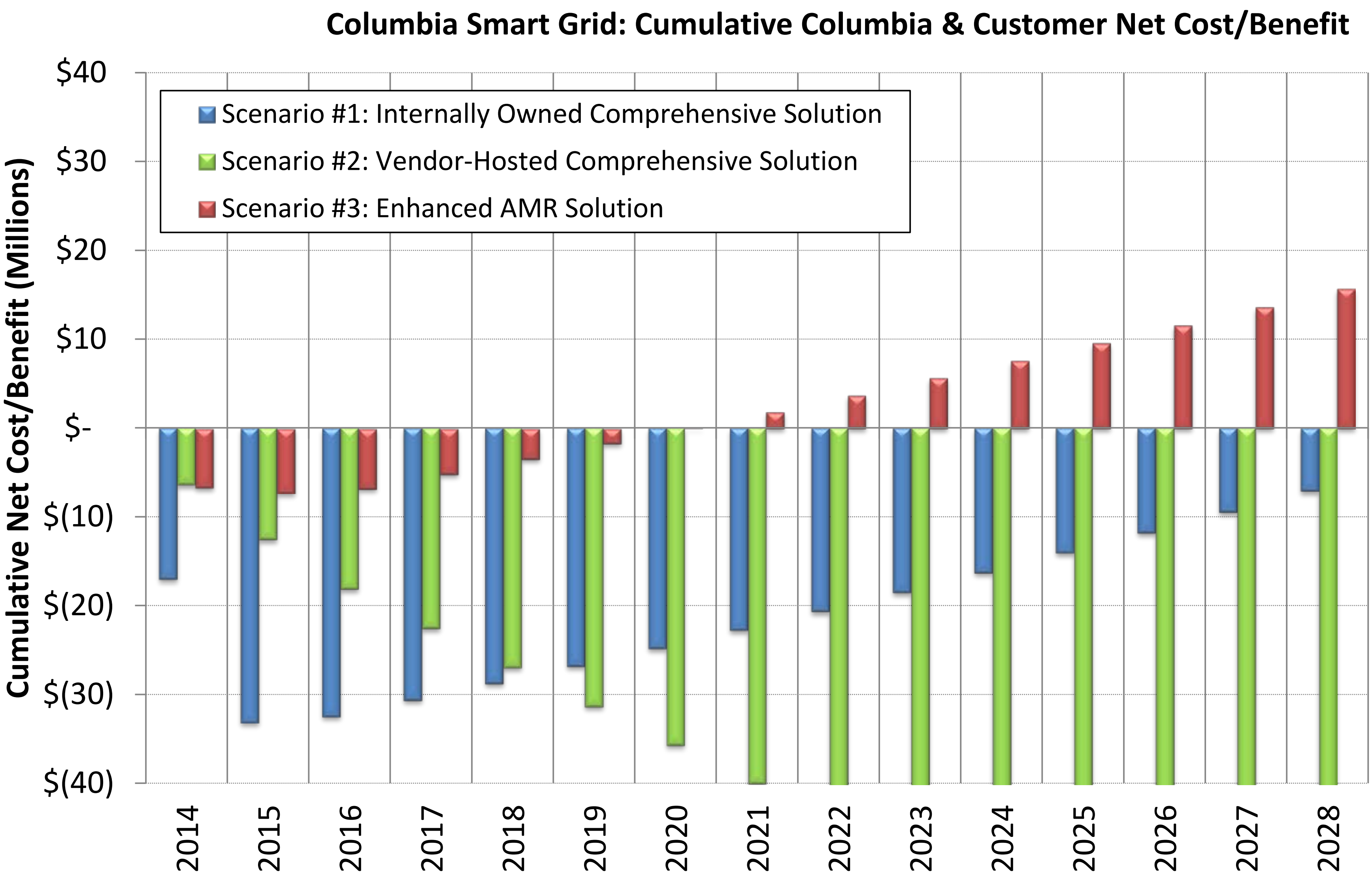
COLUMBIA COMMUNITY BENEFITS	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	15-YR TOTAL
Environmental Value																
Value from Reduced AMR Emissions (Scenario 3)	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 71	$ 1,069
Value from Reduced Outage 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**	**$ 3,225,757**	**$ 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 ($)	**39.5%**
NPV (2013$)	**$ 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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