PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

September 22, 2011

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

RE: UM 1460 – Pacific Power Report on Smart Grid Technologies

In compliance with Order No. 11-172, PacifiCorp d/b/a Pacific Power ("Company") encloses for filing its Report on Smart Grid Technologies in the above-referenced proceeding. As indicated on the attached service list, a copy of this filing is being served to all parties on the service list. Please note that Attachment A is marked as confidential, per OAR 860-001-0070, because it contains commercially sensitive information.

Please contact Joelle Steward, Regulatory Manager, at (503) 813-5542, for questions on this matter.

Sincerely,

Andrea L. Kelly / cr

Andrea L. Kelly
Vice President, Regulation

Enclosure

cc: Service List – UM 1460

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket No. UM-1460 on the following named person(s) below by e-mail and/or U.S. Mail addressed to said person(s) at his or her last-known address(es) indicated below:

Vijay A. Satyal (W)
Oregon Department of Energy
625 Marion St. NE
Salem, OR 97301
Vijay.a.satyal@state.or.us

Janet L. Prewitt (W)
Department of Justice
1162 Court St. NE
Salem, OR 97301-4096
Janet.prewitt@doj.state.or.us

Gordon Feighner (W)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
Gordon@oregoncub.org

Robert Jenks (W)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
Bob@oregoncub.org

G. Catriona McCracken (W)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
Catriona@oregoncub.org

Jess Kincaid (W)
Community Action Partnership of Oregon
P.O. Box 7964
Salem, OR 97301
jess@caporegon.org

John M. Volkman (W)
Energy Trust of Oregon
851 SW 6th Ave., Suite 1200
Portland, OR 97204
John.volkman@energytrust.org

John Cooper (W)
Grid Net
260 Branna St., Suite 510
San Francisco, CA 94107
john@grid-net.com

Christa Bearry (W)
Idaho Power Company
P.O. Box 70
Boise, ID 83707-0070
cbearry@idahopower.com

Jan Bryant (W)
Idaho Power Company
P.O. Box 70
Boise, ID 83707-0070
jbryant@idahopower.com

Lisa D. Nordstrom (W)
Idaho Power Company
P.O. Box 70
Boise, ID 83707-0070
lnordstrom@idahopower.com

Michael Youngblood (W)
Idaho Power Company
P.O. Box 70
Boise, ID 83707-0070
myoungblood@idahopower.com

Adam Lowney (W)
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
adam@mcd-law.com

Wendy McIndoo (W)
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
wendy@mcd-law.com

Lisa F. Rackner (W)
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
lisa@mcd-law.com

Wendy Gerlitz (W)
Northwest Energy Coalition
1205 SE Flavel
Portland, OR 97202
wendy@nwenergy.org

Deanna Henry (W)
Oregon Department of Energy
625 Marion St. NE
Salem, OR 97301
deanna.henry@state.or.us

Michelle Mishoe (W)
Pacific Power
825 NE Multnomah, Suite 1800
Portland, OR 97232
Michelle.mishoe@pacificorp.com

Doug Marx (W)
PacifiCorp
825 NE Multnomah, Suite 1800
Portland, OR 97232
douglas.marx@pacificorp.com

Oregon Dockets (W)
PacifiCorp
825 NE Multnomah, Suite 1800
Portland, OR 97232
oregondockets@pacificorp.com

Doug Kuns (W)
Portland General Electric
121 SW Salmon St. 1WTC0702
Portland, OR 97204
Pge.opuc.filings@pgn.com

J. Richard George (W)
Portland General Electric
121 SW Salmon St. 1WTC1301
Portland, OR 97204
Richard.george@pgn.com

Maury Galbraith (W)
Oregon Public Utility Commission
P.O. Box 2148
Salem, OR 97308
maury.galbraith@state.or.us

Michael T. Weirich (W)
Department of Justice
Regulated Utility and Business Section
1162 Court Street NE
Salem, OR 97301-4096
michael.weirich@doj.state.or.us

Robert Frisbee (W)
Smart Grid Oregon
111 SW 5th Ave., Suite 120
Portland, OR 97204
rfrisbee@si-two.com

Roy Hemmingway (W)
Smart Grid Oregon
111 SW 5th Ave., Suite 120
Portland, OR 97204
royhemmingway@aol.com

Phil Keisling (W)
Smart Grid Oregon
111 SW 5th Ave., Suite 120
Portland, OR 97204
pkeisling@gmail.com

Barry T. Woods (W)
Smart Grid Oregon
5608 Grand Oaks Dr.
Lake Oswego, OR 97035
woods@sustainableattorney.com

Dated: September 22, 2011

Ariel Son

Ariel Son
Coordinator, Regulatory Operations

PACIFIC POWER
A DIVISION OF PACIFICORP

Report on Smart Grid Technologies

In Compliance with Order No. 11-172

September 22, 2011

Table of Contents

Executive Summary

PacifiCorp operates as Pacific Power in Oregon, Washington and California and as Rocky Mountain Power in Utah, Idaho and Wyoming. Unless specifically noted in this report, all studies and actions have been analyzed for system-wide applications, including both Pacific Power and Rocky Mountain Power. PacifiCorp has created an internal smart grid department that is responsible for the management and coordination of all smart grid related technologies and activities.

PacifiCorp (or the "Company") has conducted an internal study of smart grid technologies for implementation across its six-state service territory. Through this effort, PacifiCorp analyzed smart grid technologies currently available in the market and those expected to be available within the foreseeable future. The study considered both the operational characteristics and financial impacts of implementing smart grid technologies. The results and conclusions of this study were relied upon as the primary source of information used while compiling this report.

In the electric utility industry, "smart grid" is a loosely defined term that refers to a wide variety of technologies and equipment owned by utilities and customers. Generally speaking, smart grid involves a communication network coupled with the power grid. For PacifiCorp, the smart grid definition started with a review of the relevant technologies for transmission, substation and distribution systems, including smart metering and home area networks which enable customers to respond to market price fluctuations. As these technologies were reviewed, it was recognized that the most critical infrastructure decision is the communications network selected. The network must provide robust, high-speed low latency communication for critical applications, while maintaining existing characteristics that accommodate both normal and emergency operation of the electrical system. And the network must be available at all times, even during the first critical moments of a large scale disturbance to the system.

The focus for PacifiCorp relative to smart grid technologies remains with those technologies that can be readily integrated with the existing infrastructure – technologies that do not require major electrical system changes. The technologies chosen for PacifiCorp's study were narrowed down to advanced metering systems with demand response programs, distribution management systems and transmission synchrophasors. Technologies not considered for the study included auto-healing distribution systems, distributed energy systems and direct load control programs.

PacifiCorp's study of smart grid revealed technologies that do show promise for future improvements in the operation and management of the transmission and distribution systems. However, the cost to implement a comprehensive smart grid system throughout the service territory outweighs the benefits of implementation at this time. Modification of consumer behavior would be central to realizing many benefits. Changes in usage and improved conservation have the potential to dramatically transform the electric industry; however most of the benefits associated with customer behavior changes are based on optimistic assumptions regarding the number of customers who will change their energy usage. Questions surrounding the sustainability of any consumer behavior change remain and a review of implementation of AMI at other utilities has not yet demonstrated that customers have embraced the implementation of this technology.

In order to prudently manage the costs and risks to the Company and our customers of investing in smart grid technologies, PacifiCorp believes it is necessary to allow additional time for smart grid technologies to more fully mature, i.e. allow time for technology leaders to emerge and ensure that system interoperability can be verified. The Company believes that valuable insight can be gained by analyzing the results of early adopter smart grid deployments.

The Company will continue to monitor the technology advances and developmental activities throughout the nation as more advanced metering and other smart grid related projects are built. This will allow for improved estimates of both costs and benefits. Approximately 100 smart grid projects have received funding through the American Recovery and Reinvestment Act (ARRA). American Electric Power, Duke Energy, San Diego Gas and Electric and Southern California Edison are at the forefront of these smart grid projects and are utility leaders in advancing deployment of smart grid technologies. Presently, there are 52 smart grid demonstration projects underway in the United States; 54 utilities deploying some component of smart grid; and 34 industry organizations involved in smart grid development. The Company is actively monitoring industry movements and the demonstration projects with a keen interest in assessing the costs of installation and operation of the smart grid technologies and the benefits realized (both operational and economic) through the smart grid systems.

Acronyms

The electric utility industry utilizes several acronyms that are easily confused with acronyms used in other industries. The evolution of the smart grid has increased the number of acronyms and, as technologies emerge and continue to be refined, several are used interchangeably creating confusion within the industry itself. The table below lists several of the acronyms used in this report. Definitions, if necessary, for each will be given in the appropriate section.

Acronym	Name
AMI	Advanced Metering Infrastructure
AMS	Advanced Metering System
AMR	Automated Meter Reading
CBM	Capacitor Bank Maintenance
CES	Centralized Energy Storage
CPP	Critical Peak Pricing
CVR	Conservation Voltage Reduction
DMS	Distribution Management System
DR	Demand Response
FDIR	Fault Detection, Isolation and Restoration
HAN	Home Area Network
IED	Intelligent Electronic Device
IHD	In-Home Display
IVVO	Interactive Volt-Var Optimization
MDMS	Meter Data Management System
OMS	Outage Management System
PMU	Phasor Measurement Unit
PTR	Peak Time Rebate
RAS	Remedial Action Scheme
TSP	Transmission Synchrophasors
TOU	Time-Of-Use
WAN	Wide Area Network

Introduction

Investor-owned utilities are finding themselves at the crossroads of an evolution involving advanced technologies, collectively referred to as a smart grid, and the traditional operational practices. The technologies associated with smart grid are being accelerated by recent federal legislation – including the Energy Policy Act of 2005 (EPAct), the Energy Independence and Security Act of 2007 (EISA) and the American Recovery and Reinvestment Act of 2009 (ARRA). Traditional operational practices are being sustained by lower operating costs and effectively managed customer costs, but have come under increasing scrutiny as the interest in smart grid expands across the country.

Both the EPAct and the EISA have required that each state review the requirements of the legislation and make a determination of whether or not to adopt the standards included within. While each of the states within our service territory have elected not to adopt most of the standards, they have voiced an interest in understanding what the current and future plans are for implementing the smart grid technologies.

The public interest in smart grid has also hit a crescendo due to the marketing efforts by the companies positioned to take advantage of the investments funded by the recently passed ARRA legislation. Inquiries into the Company's ability to provide a smart grid or to participate with a local city or municipality on a smart grid pilot project continue to increase. The interest in smart grids within PacifiCorp's service territory will continue to grow as neighboring states and utilities expand their advanced technologies and more information becomes available in the public sector.

In 2010, the Public Utility Commission of Oregon (Commission) initiated this proceeding, Docket UM 1460, to develop smart grid objectives and action items for the next five years. After a series of workshops and written comments on Staff's proposed guidelines for utility smart grid planning, the Commission issued Order No 11-172 in which the Commission required the electric utilities to file reports addressing, at a minimum, the following questions:

1. *What smart grid investments has the utility made in the areas of transmission, distribution, communications, and all other utility operations?*

2. *What smart grid investments does the utility plan to make in the next three to five years? What other smart-grid-related activities does the utility plan to undertake in the next three to five years?*

3. *How is the utility organized to plan for and assess smart grid investments? Who at the utility is responsible for smart grid planning and development? How does the utility ensure consistency between assessing smart grid investments and integrated resource planning?*

4. *Describe the new smart grid investments that the utility is considering. Describe the evaluations of potential smart grid investments the utility has completed or plans to perform over the next three to five years.*

5. *Describe the results of evaluations made to date and the decision made as a result of those evaluations.*

The Company addresses each of these questions in this report. First, the Company explains the status of its smart grid implementation in response to the first two sets of questions. Second, the Company's organizational structure is explained for evaluating smart grid investments in response to question three. Third, details on the Company's evaluation of smart grid investments are presented in response to question four. Fourth, the report includes a discussion of what the Company perceives as challenges and risks for implementing smart grid along with regulatory considerations. Lastly, the report includes an overview of the economic review conducted by the Company.

Smart Grid Implementation Status and Plans

Smart grid technologies are currently in a state of continuous development and evolution. Such circumstances lead to a healthy level of uncertainty regarding the benefits made available by smart grid implementation and the associated costs of deployment. PacifiCorp expects that over time, both the benefits to be achieved by smart grid and the costs associated with deployment and continuing operation will become more established and reliable. Given the current state of flux in the smart grid arena, it is difficult for PacifiCorp to identify technologies that it believes are cost effective and available for implementation in its Oregon service territory over the next five years. The Company has not implemented any of the technologies discussed in this report in the state of Oregon nor does it have any strategic plans to do so in the next five years. However, market developments may change the economics such that some of the technologies discussed herein would be prudent investments in Oregon within the near future.

While smart grid technologies do show promise for future improvements in the operation and management of the transmission and distribution systems, the present economics to implement a comprehensive smart grid system throughout the PacifiCorp territory are prohibitive. Most of the benefits associated with demand response are unproven and based on optimistic assumptions regarding the number of customers who will change their energy usage and questions surrounding the sustainability of any consumer behavior change remain unanswered.

To mitigate the risks of smart grid implementation to both PacifiCorp and its customers, the Company believes it is necessary to allow additional time for smart grid technologies to fully mature, i.e. allow time for technology leaders to emerge and ensure that system interoperability can be verified. Additional time is also needed to evaluate customer response to demand response programs which are being piloted across the country. The Company believes that valuable insight can be gained by analyzing the results of early adopter smart grid deployments.

PacifiCorp will continue to monitor the activities throughout the nation as more advanced metering and other smart grid related projects are developed. This will allow for more precise estimates for both costs and benefits and potentially allow for hardware and software costs to come down over time, improving the potential for a positive business case. With large scale deployments progressing in California, Texas and Ontario and a myriad of pilots throughout the country, the market leaders will become self-evident within the next few years and will demonstrate if sustained demand response for large-scale roll-outs is supported by the precedent pilot programs.

Organizational Structure for Monitoring Smart Grid Developments

With the increase in smart grid industry activities and the number of pilot projects initiated recently, PacifiCorp has acknowledged the need to create a dedicated organization within the Company to oversee the related activities within the Company and throughout the industry. The Company has created an internal smart grid department lead by the director of smart grid technologies. This position reports directly to the president of Rocky Mountain Power and interacts regularly with appropriate Pacific Power executives and personnel. This department will be responsible for the management and coordination of all smart grid related technologies and activities within PacifiCorp, including the monitoring and assessment of smart grid pilot projects throughout the United States.

This department will develop and manage a comprehensive strategy for smart grid and will be actively engaged with industry workgroups to learn best practices as the technologies continue to evolve. The department will create and manage an active business case to continue to assess the economic viability of the individual and combined functionalities of smart grid and provide input for the Company's annual 10-year business planning process which aligns with the integrated resource plan as technologies create proven benefits that can be included within the plan. This will position the Company to benefit from the experience of other utilities who are actively engaged in piloting and implementing smart grid technologies.

The Company also has an active internal workgroup with participants across the multiple business platforms with the Company that is focused on ensuring compliance, technology review and communications of issues related to smart grid. PacifiCorp believes that with a focused and concentrated effort, the mitigation of the risks associated with new, emerging and unproven technologies will benefit customers.

Technologies under Consideration and Evaluation

In 2010, PacifiCorp completed a smart grid business review. The purpose of this internal study was to define the scope of smart grid, identify the suitable technologies that would be required to meet the scope and examine the financial characteristics of such an investment. This report was designed to provide the internal audience with a basic understanding of the smart grid definition and components along with their costs and benefits. This report draws largely upon this 2010 study.

PacifiCorp started with a review of the relevant technologies for transmission, substation and distribution systems, including smart metering and home area networks to enable consumer demand response programs.[1] As these technologies were reviewed, it was recognized that the

[1] There are several broad categories for smart grid that remain relatively undefined as to the exact benefits and functions they provide. Distribution automation is one such category. For example, distribution automation is made

most critical infrastructure decision is the communications network selected. The network must provide robust, high-speed and low latency communication for critical applications while maintaining existing characteristics that accommodate both normal and emergency operation of the electrical system. And the network must be available at all times, even during the first critical moments of a large scale disturbance to the system.

The focus of PacifiCorp's smart grid analysis has been with those technologies that are easily integrated with the existing infrastructure – technologies that do not require major electrical system changes. The technologies chosen for the study were narrowed down to those systems shown in Table 1 and are discussed below. Technologies not considered for the study include auto-healing distribution systems, distributed energy systems and direct load control programs. Each of these components will utilize a common information technology and communications infrastructure, discussed below, to gain the maximum benefits through reduced duplication of facilities.

Smart Grid Technologies Analyzed
Advanced Metering System
Demand Response
Home Area Networks
Distribution Management System
Interactive Volt-Var Optimization
Conservation Voltage Reduction
Capacitor Bank Maintenance
Centralized Energy Storage
Outage Management System
Fault Detection, Isolation and Restoration
Transmission Synchrophasors

Table 1

With the large capital investment required to enable smart grid elements, it is essential that PacifiCorp prudently consider all of the costs and benefits realized through these technologies. Investment in smart grid should only be made when the utility and its customers can be reasonably assured that net benefits, both financial and operational, will be realized through smart grid implementation. PacifiCorp believes that additional time is required to allow the smart grid industry to develop and evolve. Allowing the market to more fully develop prior to investment by the Company will ensure that market leaders are identified and that system interoperability is verified. The Company will also be able to glean valuable information from

up of several functionalities that have intelligent interoperability amongst themselves to enable a system that will maximize the system for efficiency and reliability. A system that can increase efficiency through integrated renewable and distributed generation resources, better system balancing, actively managed power factor and line losses and has the ability to identify, locate and isolate faulted conductors and automatically restore power to areas outside the fault zone will require that redundant and oversized systems be created. To enable the complete spectrum of distribution automation, a fully redundant system is required. This level of redundancy comes at a cost that will not, according to the analysis, support any economic based decision and is not addressed in this report.

smart grid deployments of other utilities. With deployments beginning throughout North America, including California, Texas and Ontario and a myriad of pilots elsewhere enabled through the recent ARRA funding opportunities, the market leaders will become self-evident as the systems begin to mature during the next few years.

Information and Communication Infrastructure

The backbone of the smart grid is the information and communication infrastructure and is critical to the success of the program. The system must be robust enough to not only handle the amount of data generated by the advanced metering system and the intelligent electronic devices (IEDs) deployed throughout the electricity delivery infrastructure, but have the intelligence to prioritize and react to the data delivered. Information related to system disturbances or outages must be given fast, preferential handling over lower priority items such as meter readings. The IT system must process the data and interpret which applications need the data and the format required. It must be able to store the data in an easily retrieved, archived format and utilize that data for historical comparative purposes when needed to make proper decisions for applying corrective actions to manage the electricity delivery infrastructure in an efficient manner.

Figure 1 portrays a smart grid information and communications architecture that must be developed to fully implement the entire scope of the PacifiCorp smart grid. Note that the transmission synchrophasors are not part of the model. That system is best operated as a stand-alone application due to the high-speed processing and handling requirements of the data received from the PMUs.

PacifiCorp Smart Grid Architecture

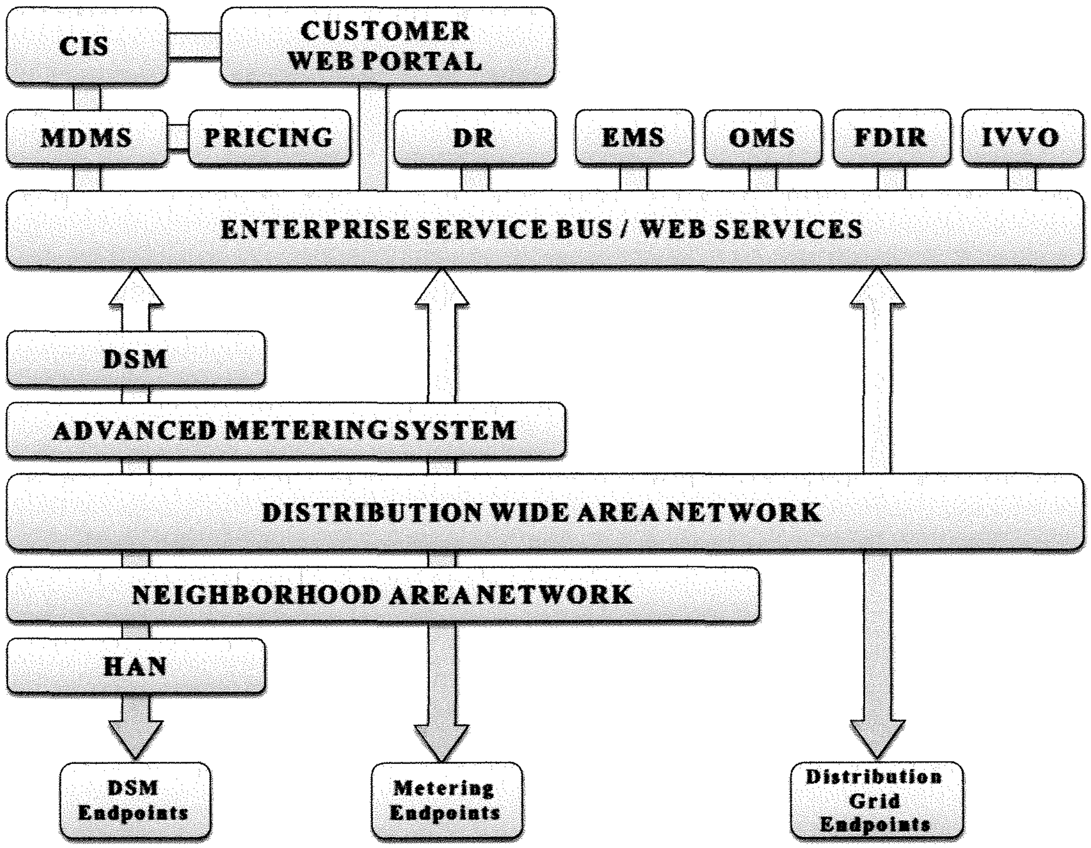

Figure 1

Communications Network

The backbone of a successful smart grid operation is a reliable, resilient, secure and manageable communication infrastructure. The broad scope of smart grid application areas, coupled with the large and geographic expanse of PacifiCorp's service territory and the diversity of the customers and communities we serve, dictates a large, complex, and costly smart grid communications network.

The intent of smart grids is to provide better efficiencies in the production, transport, and delivery of energy. This is realized in two ways:

- Better real-time control: the ability to remotely monitor and measure energy flows more closely and manage those flows in real time.
- Better predictive management: the ability to monitor the condition of different elements of the network to predict failure and direct proactive maintenance.

These mechanisms imply more measurement points, remote monitoring and management capabilities than exist today. It also requires a greater reliance on reliable, robust and highly available communications. Optimization also demands either widespread active customer participation or acquiescence to mandatory centralized control.

The new smart applications are dictating the need for a wider deployment of communications, through the distribution circuits and all the way down to the customer premises. These functions were never envisioned for PacifiCorp's existing communication systems. New communication services must support such endpoints as advanced metering systems (AMS), automated switches, power quality devices, fault indicators and capacitor banks. At the same time, the communications network must continue to support the operational services independently of external events, such as power outages or public service provider failures, yet be economical and feasible to maintain.

As depicted in Figure 2, the smart grid communications network will leverage existing investment in the bulk transport network by re-using the existing fiber and microwave systems where possible but expanding it significantly to support other services. To reach out to support customer and distribution assets, new wide area networks (WANs) will need to be built out or leased.

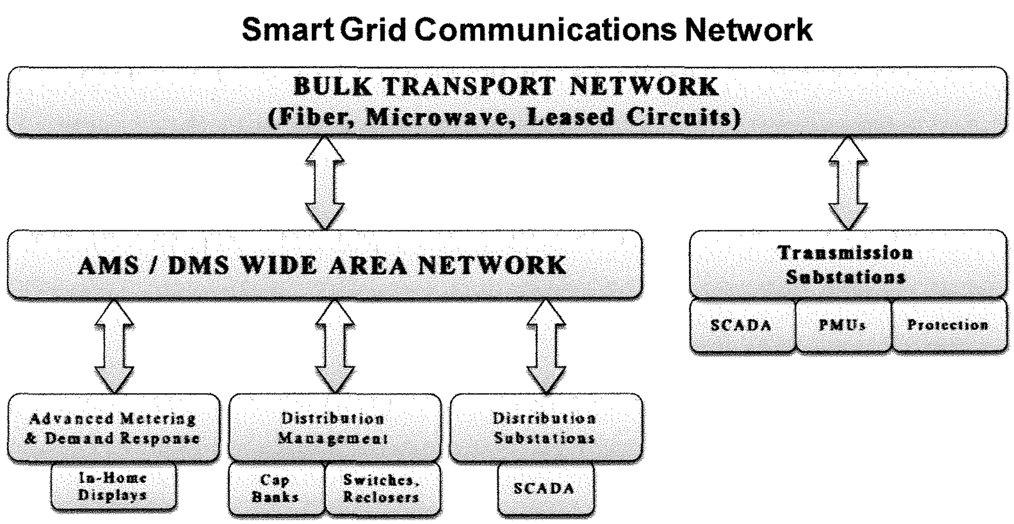

Figure 2

The vision is to efficiently leverage the long-haul communication assets currently deployed and not create "silos" of purpose-built networks. The key to ensuring this does not happen is to guarantee the smart grid components communicate with the networks using standardized protocols. This will also help promote interoperability of different vendor components, thereby encouraging competition, and lowering component and maintenance costs. One way to help achieve this is to ensure any smart grid roadmap aligns with the Smart Grid Interoperability Standards Project that is being developed by the National Institute of Standards and Technology (NIST). These standards are not slated to be fully ratified until 2012. PacifiCorp has monitored and participated in this Project through our participation with the Edison Electric Institute.

Advanced Metering System (AMS)

AMS provides the highest level of meter reading automation and satisfies all requirements for the smart grid system. AMS provides the data required to fully integrate meter reading, demand response, outage management, and distribution management functions. These systems have the capability to offer an "in-home display" of information to customers and integrate direct load control where the utility sends signals to cycle loads (e.g., A/C, water heaters, etc.). Furthermore, these systems are capable of integrating indirect load control where the utility sends pricing signals and consumers can program the behavior of their individual appliances to respond to changing prices.

Advanced metering infrastructures, commonly referred to as AMI, provide the same metering data levels as automated meter reading (AMR, or "drive-by") systems but provide enhanced capabilities by collecting interval data from all meters. This interval data can be used for time-based rates and critical peak pricing programs but lack the direct customer notification and integration of in-home displays. These systems can provide additional benefits in the form of outage detection and restoration messages via the system. Demand response programs cannot be implemented directly through most AMI systems. Demand response programs are implemented with direct load control through a separate system (e.g. paging, etc.) and the impacts measured with the AMI system. Even with their advanced functionalities, AMI systems do not meet all the requirements for the smart grid.

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

Note that neither home area networks nor in-home displays are a required component of AMI as defined by FERC, although they offer benefits for demand response in addition to those possible with AMI-supported time-varying pricing alone. Also, control of distribution equipment (reclosers, sectionalizers, capacitors, etc.) is not a required component of AMI. In combination, these additional features begin the framework for a "smart grid".

Automated meter reading (AMR) systems are typically defined as a system that only automates the manual meter reading process. These systems deliver accurate and reliable monthly meter readings to billing on a cycle basis at a cost typically lower than manual reading methods. Mobile or drive-by systems are the most commonly implemented automated meter reading solutions in the industry. Some AMR systems, including those installed by PacifiCorp, are capable of migrating to a one-way fixed network system that meets the basic requirements of AMI as defined by FERC.

The term "AMI" is used routinely in many discussions and papers and to support the users' own purposes for the system being proposed. AMI is used to define systems ranging from one-way fixed networks to two-way advanced metering systems. The functional requirements of the metering system must be known to determine the reasonableness of the system proposed. By using identifying names for the systems and not relying solely on the acronym to differentiate systems will assist in the understanding of what the metering system will deliver to the user.

For the purpose of this report, the term "advanced metering system" will be used to maintain clarity. Advanced metering systems provide for the definition as outlined by FERC and include all the functionality required to support the smart grid. Automated meter reading systems, and most advanced metering infrastructures, cannot be migrated to an advanced metering system without significant costs.

Demand Response (DR)

One of the key requirements to encourage customers to change energy usage patterns is to make the proper pricing signals available that encourages changes in the time energy is utilized. The most common price signals in the industry today are time-of-use (TOU), critical peak pricing (CPP) or peak time rebate (PTR) programs. A combination of TOU/CPP or TOU/PTR pricing programs are the most prevalent and present the greatest opportunity for creating reductions in energy usage during the most critical times when system peaks are present.

TOU tariffs create pricing programs that present to the consumer the real-time or relative price of energy at various times during the day. By selling electrical energy at the real-time price, it is anticipated that consumers would shift their consumption from the peak periods, or higher priced hours, to times when the cost of energy is lower. This shift in consumption will reduce the peak demand and increase the load factor on the electrical system. The most common TOU programs have on-peak and off-peak pricing components and a few also incorporate shoulder pricing. Critical peak pricing schemes are included in more advanced pricing structures to encourage conservation of energy during those few hours, typically 100 hours or less, each year when electrical demand peaks and places stress on the system.

One of the unique characteristics of CPP programs is the "rebound" effect that occurs at the conclusion of the CPP event. This rebound effect is caused when the deferred load, primarily air conditioning, increases dramatically at the end of the CPP event in an effort to bring the customer's residence back to a "normal" comfort state. If the CPP event occurs for an extended period of time, the rebound effect becomes more pronounced and can create a new daily system peak higher than what the normal peak may have been. This is an anomaly that does exist but has insufficient studies to make it possible to calculate the magnitude and overall system effect with any degree of accuracy.

It has been stated that, given the proper pricing signals, consumers will reduce their peak energy usage during critical peak pricing periods. However, to date, only simple pilots of CPP pricing programs have been conducted and have provided less than meaningful statistics on the sustainability of consumer behavior change. Thus, there is no history that would allow PacifiCorp to understand how much and how long customers will voluntarily participate in a dynamic pricing program for the life of the program.

PacifiCorp has provided a comprehensive set of demand-side management programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. These early efforts involved the management of water heating, air conditioning and irrigation loads and laid the foundation for the air conditioning, irrigation, and business curtailment programs the Company operates today. Although these programs are voluntary and rely on site specific control equipment and communication protocols for controlling loads, the Company has built a control network of participating customer end use loads of nearly 800 megawatts. The control technology and load management practices employed are some of the most advanced in the industry and together with the Company's conservation and energy efficiency efforts demonstrate that PacifiCorp is actively engaged in improving the efficiency and management of its system, in employing education, equipment, and price incentives to maximize system performance.

Moving from site specific investments in demand response technologies and a voluntary approach to participation to a broader system-wide deployment of information systems and a price responsive system to drive usage patterns marks a fundamental shift in philosophy on how to manage end-use loads and engage customers.

<u>Home Area Networks (HAN)</u>

In context of smart grid, the term "Home Area Network" has become synonymous with in-home displays, programmable communicating thermostats and home area networks. Each of these devices serves a different level of functionality enabling the consumer with more control over their energy usage. In-home displays and home area networks provide information to the consumer on which they can make operating decisions. Programmable communicating thermostats can be used for either direct-load control by the electric utility, when provided with the appropriate permissions and access by the customer, or used in a home area network scheme by the customer.

One of the key requirements to encourage customers to reduce energy usage is to make the proper pricing signals available to the consumer through either an In-Home Display (IHD) or through their Home Area Network (HAN). In-home displays range from simple "fridge magnets" equipped with three levels of indication via green, yellow and red lights to very sophisticated displays that interface with the customers home area network. The simple fridge magnet display warns the customer of an upcoming critical peak event, and the resultant increase in energy prices, with the yellow indicator. This "yellow light" warning allows the customer time to reduce their load prior to an increase in energy prices. The red indicator light remains on during the event time frame. When pricing structures return to normal on-peak or off-peak state, the indicator light reverts to green.

Home area networks (HANs) enable the customer to leverage the real-time information received via the advanced metering system into automated actionable tasks that can reduce their energy consumption at peak times as well as enabling overall energy conservation. The advanced metering system provides for transmission of key data, including usage and price signals, to the customer who can then use this information to manage and lower their consumption. To utilize the home area network, more sophisticated communicating devices are required to allow the customer to program automatic actions to pricing signals and critical peak events. Home-area networks coupled with automated home appliances can give individuals the sense of empowerment over their electricity consumption and will help drive consumer smart grid acceptance.

Distribution Management System (DMS)

As the distribution systems continue to become more sophisticated and optimized in their operation, greater precision in operational data and minute-by-minute management are keys to its long-term success. A Distribution Management System (DMS) brings to the utility a variety of advanced analysis and operating tools for management of the distribution system. It integrates several systems and functions that are currently operated independently in today's environment. Specifically, outage management, switching operations, lock-out and tagging procedures, fault calculations, load flows and real-time state estimation routines. Additionally, when integrated with Interactive Volt-Var Optimization program (IVVO) functionality, the distribution management systems can start to manage voltage to minimize line losses and energy needs while optimizing the delivery of energy to consumers. A DMS utilizes strategically placed equipment, including distribution transformers, distribution reclosers, motor-operated switches, and fault detection devices, integrated with backbone communications as inputs to an electronic model which records and calculates key values integral to operating the system. Upon these calculations, key settings are enabled via appropriate communications paths which increase the efficiency of the system.

Distribution management systems create an intelligent distribution network model that provides ongoing data analysis from field deployed IEDs to maximize the efficiency and operability of the distribution network. A complete distribution management system provides distribution engineers with near real-time system performance data and historical performance metrics. This decreases the planning time requirements, increases visibility of system status and improves reliability metrics through better application and management of the distribution capital budgets. With appropriate data inputs from field IEDs, the DMS will be able to analyze the distribution network for both normal and emergency states and performs the following functions required for the interactive volt-var and fault detection, isolation and restoration activities:

- Monitor unbalanced load flow and determine if there are any operational violations for normal state and reconfigured distribution feeders.
- Determine the optimal position and operating constraints for the various power transformer taps, line voltage regulators and capacitors along a distribution feeder and manage the open/close positions of these devices.
- Receive fault data and run a short circuit analysis to determine the possible location(s) of the fault.
- Analyze the system during faulted conditions and determine the redistribution of the available load to adjacent feeders and substations.
- Suggest the switching sequence required to isolate the fault and restore power to as much load as possible outside the fault zone.
- Suggest the switching sequence for line unloading should a condition arise where an operator needs to reduce load from a specific substation.

Prior to the integration of IVVO or fault detection, isolation and restoration systems as identified for PacifiCorp's smart grid, it is required that detailed network models of the distribution systems be created including three-phase unbalanced and system connectivity models. PacifiCorp has invested in software technologies that satisfy both of these requirements positioning itself for a functional distribution management system that will incorporate the emerging technologies for smart grid.

Interactive Volt-Var Optimization (IVVO)

Current standards for voltage delivery values, as established by the American National Standards Institute (ANSI), allow for values within the range ±5% of nominal at the point of delivery to electric service customers. For standard residential voltage of 120 volts nominal, this ANSI standard allows the Company to deliver voltages ranging from 114 to 126 volts.

To maintain the voltage within the specified range across the entire distribution circuit, the voltage at the distribution substation buss is set at the upper limit of the designed voltage. The line voltage continually degrades as a function of line length, impedance and loading and, if not properly managed, will degrade to levels below the lower limit of the voltage standard. At a point on the distribution system and prior to the where the voltage would have degraded below the acceptable limit, a capacitor bank or voltage regulator is installed to increase the voltage level to an acceptable limit at a value less than the upper limit of the voltage standard.

The decision of which device to install is driven by the characteristics of the circuit at the point of application. The engineering consideration and design parameters used for this decision are complex and will not be discussed in detail other than to state that power factor, voltage levels and peak circuit loading must be considered. As power factor approaches unity (100%) across the distribution feeder length, line current is decreased and distribution system losses are reduced.

The IVVO program utilizes these strategically placed distribution voltage regulators and capacitor banks for voltage and power factor control to reduce system losses associated with line losses on the distribution system. With real-time communications installed at each device, the voltage regulators and capacitor banks are automatically controlled by a module in the DMS.

In a traditional distribution system the downstream devices are contingent on the upstream devices and their pre-programmed operational parameters. As the number of distributed generation sources increases, the present voltage and power factor management schemes will no longer be able to maintain satisfactory levels. The DMS actively manages the voltage levels and power factor and adjusts the regulators and capacitors independently to produce a level voltage profile across the distribution system. This leveled voltage profile is only achievable through the complete integration of direct communication with the field equipment and the algorithms in the DMS. Through power factor correction, a more regulated voltage level is created and maintained along each distribution feeder. By improving the power factor, line loading is decreased and, in turn, reduces the line losses across the distribution system.

In addition to minimizing line losses over the distribution system, the Company is exploring the need for voltage and var management programs in response to the impact of the Company's irrigation load control programs. When electrical system needs arise that require an immediate reduction in load, the Company has the ability to control large quantities of irrigation load in Idaho and Utah (through demand-side management programs approved by the Idaho Public Utilities Commission and the Public Service Commission of Utah, respectively) to reduce the stress on the generation, transmission and distribution systems. However, when large amounts of load are dispatched off the system in a short period of time, there are consequences with voltage rise that can adversely impact other customers on the system. While capacitor banks have been used in local control methods to correct voltage and power factor, these current methods are not responsive enough to prevent voltage excursions from occurring.

PacifiCorp is conducting a formal exploration of voltage optimization programs to address this issue. The intelligent integration of the load control and voltage optimization programs will be required to minimize and eliminate voltage excursions associated with large scale load reduction. The Company is exploring several technology options, including both centralized and distributed intelligence, to ascertain the most prudent solution to this complex problem. This effort began in June 2011 and is expected to take up to 12 months to fully complete.

Conservation Voltage Reduction (CVR)

For those circuits where the load is primarily resistive (which is typical of residential loads), the utility can reduce system loading during peak hours and emergency conditions by lowering the line voltages. The ability to mitigate system losses by decreasing line currents is achieved by reducing voltages to minimally acceptable levels as defined by the American National Standards Institute.

A conservation voltage reduction (CVR) module can be added to the distribution management system and utilizes the same field components as the IVVO system. Once the CVR module is installed the system voltage can be reduced across the feeder length since the IVVO system has created a leveled system voltage profile along the feeder length. The CVR module of the DMS uses the advanced metering system to obtain delivery voltage information from selected metering endpoints along the circuit. The CVR system then adjusts the system voltage by switching capacitor banks or adjusting regulators to lower the system voltage. This in-turn reduces the delivery voltage to the customer and, assuming a resistive load, reduces the load current which reduces the system loading through a reduction in line current.

PacifiCorp is concerned about the potential risk of increased customer complaints stemming from low voltage (i.e., malfunctioning equipment, flickering lights, shrunk TV screen, etc.). Reduced voltage can have the effect of increasing the exposure of sensitive customer equipment to voltage sags and nuisance tripping. This can be particularly problematic for sensitive and expensive laboratory and hospital equipment, as well as tools and computers. Increased customer complaints are generally received when service voltage falls below 114 volts at the customer meter. It is imperative that the IVVO/CVR system respond quickly to sub-standard voltage conditions to prevent unintended consequences and operational problems for customer's equipment.

In response to Washington state's Initiative Measure No. 937 (which requires investor owned utilities to pursue all cost effective electric conservation), the Company has initiated an in-depth analysis of the cost-effectiveness, reliability and feasibility of a conservation voltage reduction program in the state of Washington. The engineering analysis is being conducted by Commonwealth Associates, Inc. and the full report is expected to be finalized by the end of 2011. The report will review the distribution efficiency opportunities for 19 distribution circuits in the Company's Washington service territory. The results of this study will provide information necessary to determine if a distribution efficiency program of this nature can provide benefits to the system in each of the jurisdictions in which the Company provides service. This effort is explained in more detail in the Company's 2011 integrated resource plan proceeding.

Both Pacific Power and Rocky Mountain Power have a history of managing their distribution systems for optimal power factor and voltage profile, reduced line losses and increased system efficiency. This attention to managing the distribution system has resulted in the installation of numerous capacitor banks and voltage regulators over the lifetime of the distribution system. This continuous management of the distribution systems has resulted in a distribution system that is very efficient and while the results of the study have not been fully vetted, a rudimentary extrapolation of the results has demonstrated that less that 15% of the distribution circuits may benefit from the application of more voltage optimization hardware and devices.

Capacitor Bank Maintenance (CBM)

Typically, capacitor banks are visually inspected once per year to determine their operational state and inspect for damaged tanks or blown fuses. If the capacitor bank fails or becomes inoperable in the interim, the complete benefits of the IVVO system and the individual capacitor banks go unrealized. With the IVVO system and its advanced reporting capabilities, it can detect when a capacitor bank has operational problems without the need for a field inspection. This reduces the costs of the annual inspection programs. When a problem is detected, the IVVO module creates a trouble order for the problem. This reduces the time the capacitor bank is out-of-service and maximizes the benefits realized from the voltage and var optimization routines.

Centralized Energy Storage (CES)

One of the benefits of a smart grid is the ability to integrate renewable energy sources into an electricity delivery system that is dominated by fossil fuel generation. In contrast to fossil fuel generation, that is available on demand, renewable energy sources cannot be scheduled and must be considered as variable. If a significant percentage of generation capacity comes from these variable sources, the smart grid will not be able to pick up the slack when the wind doesn't blow or the sun is not shining. There are two primary ways to fill this generation gap without the use of fossil fuel generation: demand response programs and centralized energy storage (CES).

CES can be used to store wind or solar generated energy, which typically occurs at non-peak hours, and release that energy during peak hours. Several new technologies are currently being researched throughout the industry including electrical battery storage, pumped hydro storage, flywheel energy storage and compressed air energy storage. Each of these solutions has unique characteristics, applications and costs. Electrical battery and flywheel energy storage are the emerging technologies that show significant promise for widespread application and use in the utility industry.

Electrical battery storage for utility scale applications, in contrast to single cell rechargeable batteries used in cell phones and other small appliances, require energy levels that can only be produced by converting chemical energy to electrical energy. Lithium-ion batteries are common in small applications, but building large-scale lithium-ions remains prohibitively expensive. Flow batteries are touted by some as the leading option for practical, utility-scale, high-capacity electricity storage. Sodium-nickel-chloride and lithium-iron-phosphate batteries are being developed and show some promise for large scale applications. Some cutting-edge solutions aggregate many small amounts of battery storage – electric vehicle batteries or uninterruptible power supplies. However, it is not apparent that this technology will be available for commercial or large-scale deployment any time in the near future.

Electrical battery storage provides the quickest response to energy demands. Batteries have the ability to store electrical energy generated by renewable resources, usually during off-peak times, and then release that energy when required during on-peak times. When strategically located, these battery storage solutions can also be used to delay increases in substation power transformers which overload only during short periods and at peak hours of the year.

Flywheel energy storage works by accelerating a rotor (flywheel) to a very high speed and maintaining the energy in the system as rotational energy. When energy is extracted from the system, the flywheel's rotational speed is reduced as a consequence of the principle of conservation of energy, conversely adding energy to the system results in an increase in the speed of the flywheel. Such flywheels can come up to speed in a matter of minutes and much quicker than some other forms of energy storage. Flywheel energy storage systems are also referred to as "electromechanical battery systems" as their ability to respond quickly to energy demands are similar to chemical battery systems. On July 14, 2011, Rocky Mountain Power filed an application with the Public Service Commission of Utah to defer the costs ($625,000 in total) of a flywheel battery energy storage demonstration project and to recover those costs through the Schedule 193 demand-side management surcharge.

Outage Management System (OMS)

All electrical distribution systems are subject to faults caused by storms and other external events as well as failures related to aging and overloaded systems. When these faults and failures occur, protective devices such as circuit breakers, reclosers, sectionalizers and fuses operate to limit the resultant outage to the smallest practical area. Information on the outage is currently obtained through SCADA systems, where available, and/or notifications to the Company's customer service call centers. These notifications, when interfaced into the Company's connectivity model, inform the Company that an outage exists and allows for the dispatch of personnel to manually identify the location and commence restoration to areas outside the fault zone. When appropriate amounts of data are received from customers, intelligence within the current outage management software can make assumptions as to where a fault may have occurred.

To accelerate service restoration times, the integration of intelligent electronic devices (IEDs) in distribution line equipment, specifically reclosers, sectionalizers and faulted circuit indicators, provide the outage management system with intelligence that can be used to isolate the faulted sections of the system in reduced time frames.

Fault Detection, Isolation and Restoration (FDIR)

A Fault Detection, Isolation and Restoration program (FDIR) utilizes strategically placed distribution reclosers, motor operated switches and fault detection devices to automate restoration. The program works by adding communication to existing reclosers, motor-operated switches and fault detection devices. The devices then communicate their status back to the DMS which tries to determine the fault location and then uses feeder ties to automate restoration to areas outside the fault zone where adjacent circuit capacity exists. The DMS then sends out a signal to open or close fault isolation devices and switches to restore the maximum number of customers. The switching is typically done within one to two minutes.

Once all automated restoration switching has been completed, the DMS can notify the distribution dispatch center of the faulted zone. The dispatch center can then send crews to identify the cause of the outage and make the repairs. By knowing the location of the faulted zone, the time related to line patrolling is reduced thus shortening the outage time.

Transmission Synchrophasors (TSP)

The existing PacifiCorp transmission system relies on many electronic elements to ensure reliability and to maximize the transmission capacity available on individual lines and transmission paths including remedial action schemes and high speed digital relays. The NERC glossary defines a Special Protection System (SPS) as "An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme (RAS)." PacifiCorp uses the term Remedial Action Scheme and will continue with that terminology throughout this report.

RAS have become more widely used in recent years to provide protection for power systems against problems not directly involving specific equipment fault protection. RAS, along with high speed digital relays, are the latest "smart" technologies used to maximize the operational efficiency of the transmission system. RAS are designed to monitor and protect electrical systems by automatically performing switching operations in response to adverse network conditions to ensure the integrity of the electrical system and avoid network collapse. RAS uses a combination of programmable logic controllers and high speed digital relays to provide this protection. For example, the sudden loss of one transmission line may require dropping a generator's output to prevent the overloading of an adjacent and parallel transmission line. Without the RAS, the parallel line would become overloaded in a short period of time and trip itself off line to be protected from damage. Without the RAS, a cascading outage would not be easily avoided.

Transmission smart grid is generally synonymous with the phase measurement unit (PMU) (or synchrophasor) and the communication network to link many PMUs to a central processor. The PMU is the building block for transmission system smart grid applications. The intelligent use of PMU data can lead to a more reliable network by comparing phase angles of certain network elements with a base element measurement. The PMU can also be used to increase reliability by synchrophasor assisted protection because of better line condition data relayed faster through the communication network. Future applications of this precise data could be developed to dynamically rate transmission line capacity, real time and real condition line/path ratings and real time power factor optimization. Such dynamic ratings would require vast changes in the current contract path (a transmission owner's rights to sell capacity are based on contracts not actual flows) transmission capacity methodology currently employed by PacifiCorp and other transmission operators in the Western Electric Coordinating Council (WECC). PMU implementation and further development may enable transmission operators to integrate variable resources and potentially energy storage more effectively in to their balancing areas and minimize service disruptions. A self-healing transmission grid would reduce outages by "detouring" energy to other paths with available capacity.

Several suppliers offer PMU units that can be used today. In fact this technology has been around since 1979 according to General Electric. The communication network elements are generally available. PMU deployment is dependent on a wide area network of sufficient geographical coverage, bandwidth, reliability, security and latency to enable PMU functions. Specific data processing and decision logic would be required for operations.

A wide area network constructed to support a network of PMU devices would enable distribution improvements at transmission-distribution interface substations. These substations can serve as the common communication and data gathering node for both transmission and distribution data and control. The General Electric topology model envisions a PMU, a micro grid coordinator, and substation operations logic co-located at the substation.

The early benefits of synchrophasor installation and intelligent monitoring of the transmission system are focused on increased reliability of the transmission system. The deferral or elimination of new or upgraded transmission lines is not facilitated by the synchrophasor program as envisioned in this report. Much research is needed to implement dynamic ratings which could, in theory, reduce the future need for additional transmission lines. Transmission energy storage and load reductions could defer or eliminate the need for additional central station generation, which in turn would defer or eliminate some future transmission lines.

Synchrophasor Demonstration Project

PacifiCorp is participating in the WECC Western Interconnection Synchrophasor Project (WISP) which includes matching funding under a Smart Grid Investment Grant (SGIG) of 50%. WISP is a collaborative effort between partners throughout the U.S. portion of the Western Interconnection.

PacifiCorp has committed $800,000 of funding in order to engage in planning, design, engineering and operational activities to identify and deploy synchrophasor technology at the most effective locations on PacifiCorp's system to the benefit of customers and the WECC region.

The goal of the WISP program is to increase the coverage of PMUs throughout the west, implement a new secure, stable, high performance WAN, and deploy enhanced situational awareness applications, tools and processes and to identify the benefits of the technology. Synchrophasor data and supporting technologies will be used by WECC and entity partners to identify and analyze system vulnerabilities and evolving disturbances on the western bulk electric system and take timely actions to avoid wide-spread system blackouts. The system will provide WECC Reliability Coordinators (RC) and Grid Operators in the Western Interconnection with the network, infrastructure, tools and applications necessary to leverage phasor measurement technology in the planning, analysis, operation and monitoring of the grid with the primary goal of improved reliability.

Technology Dependency

Many of the technologies required to migrate the existing electrical system to a smart grid are dependent upon preceding technology deployment. To gain the full benefit of the individual technologies, it is necessary that all interdependent and preceding technologies are fully integrated. The information and communications technologies are required for all smart grid applications and cannot be excluded in any program analysis. To harvest the full benefit of IVVO, the DMS must be developed and integrated into the information and communications systems prior to field deployment of the "smart" capacitors and line regulators. Figure 4 illustrates the technology dependencies for the PacifiCorp smart grid. The illustration shows that the smart grid must be built from "the top down" and along the paths indicated to build a functional system. The only exception is the transmission synchrophasor system which can be built out independently of the others.

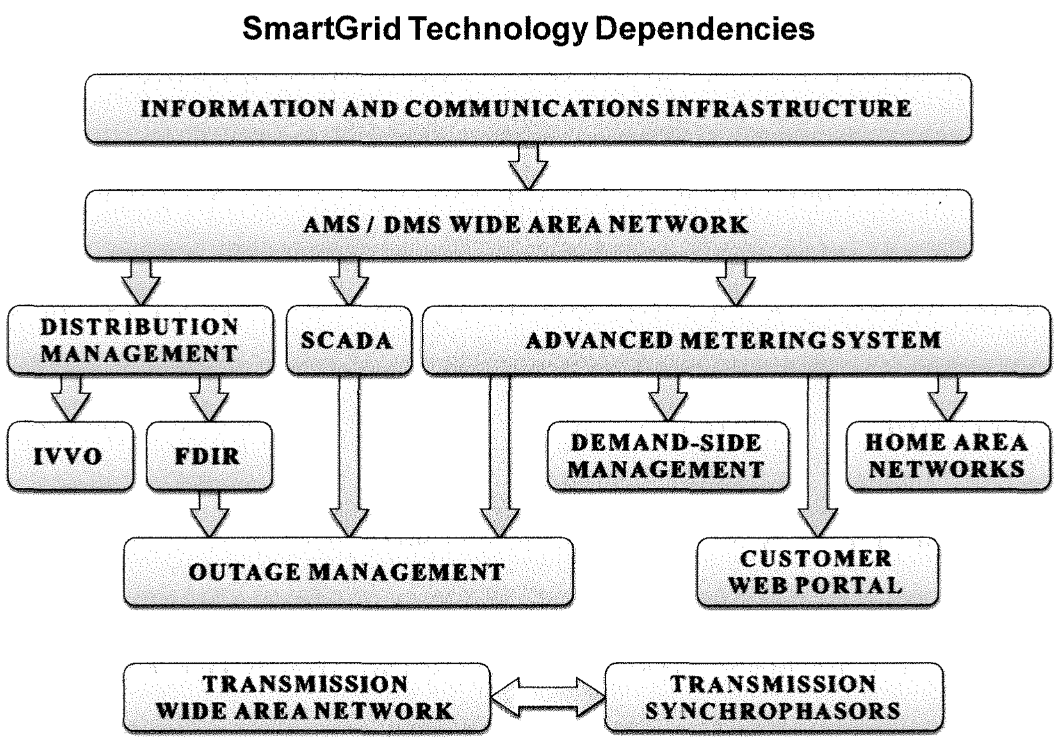

Figure 4

Challenges and Risks of Implementing Smart Grid

While there are expected to be many upsides to the smart grid, there are many challenges to its deployment and the future operations of the electric system. Some of these challenges relate to integration of communication standards (interoperability), ensuring proper security for devices, systems and customers, modifying communications with customers and finally the impact that disruptive technologies may create on the electric distribution system.

It must be recognized that the electric system in place today was a result of an expansion that was predicated upon economics; as such, the system is engineered to provide adequate service at low costs. As system growth has occurred, that fundamental design precept has not been materially altered. Smart grid is now positioned such that the fundamental economics are no longer the most critical aspect of the system; rather the ability for the customer to engage with the electric delivery system is of higher priority. This shift will result in significant costs for current and future system investment. Equipment, communications protocols and even staff will be more technologically advanced, and will require more routine "refreshing" to maintain compatibility with further advancements.

Interoperability Standards

The current lack of interoperability standards risks premature obsolescence of equipment and software installed prior to widespread adoption of such standards. As electric utilities continue to expand existing infrastructure or begin implementing new smart grid related systems, long-term investments should support a strategic plan to minimize the risk of technology obsolescence. There are currently several working groups developing standards for the entire spectrum of equipment, devices and end points for the metering and smart grid systems, including interoperability of components. The Energy Independence and Security Act of 2007, has specified that the Department of Energy (DOE) champion this effort with a completion date of 2012. The DOE authorized the National Institute of Standards and Technology (NIST) to develop uniform protocols that facilitate information exchange between smart grid devices and systems. These standards, along with industry adoption, are crucial to the mitigation of risks associated with implementation and deployment of the smart grid throughout PacifiCorp's service territory.

NIST is also drafting standards to address issues of inter-operability between AMI vendors and has issued its "roadmap" for developing the necessary standards (the draft NIST Framework and Roadmap for Smart Grid Interoperability Standards). This roadmap targeted the end of 2010 for the release of the most important standards, but NIST has cautioned that "several hundred standards that are identified or developed over the span of several years may be required to achieve secure, end-to-end interoperability across a fully implemented Smart Grid."

The smart grid initiatives that have evolved over the past few years have given birth to an incredible array of new markets and opportunities based on innovative technologies PacifiCorp probably wouldn't have imagined at the outset. That point also stresses how extremely important interoperability standards are to a functional, reliable smart grid.

Stakeholders who are not monitoring the NIST activities risk having current investments becoming prematurely obsolete and will be challenged to achieve all the benefits that are expected from existing equipment. In addition, many of the smart grid standards under review are immature or not even developed while some prominent standards are not included – emphasizing the need for electric utilities and commissions to remain conservative in developing plans for "smart grid" systems until standards are established and proven to deliver expectations.

Security

The smart grid increases the amount of intelligent data to a level never before seen in the electric industry. This data includes priority data for electrical system operation, customer data and usage patterns and generation and transmission operational information. This data will be transmitted mainly over secure communication systems, many of which will have wireless components. The fact that the data is transmitted wirelessly increases the risk of cyber-attacks against the electrical infrastructure.

The security of customer and operational data presents one of the greatest unknown risks at this time. North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) reliability standards were designed to protect the bulk power system against potential cyber security attacks. Yet, these standards do not address the evolving smart grid market and the vulnerabilities that may be present as more utilities install advanced communications networks. As utilities progress towards the smart grid, enhanced security measures and more stringent requirements will be necessary. Their enactment will increase the overall cost of managing the smart grid.

Customer Communications

The smart grid opens a whole new channel of communication between the Company and its customers, but this new communications channel is fundamentally different from the past. Transmission of usage data can be conducted in real time, not just on a monthly basis as in the present. The need to broadcast pricing alerts to smart thermostats, email addresses and text messaging devices happens virtually instantaneously. Responses from customers can be immediate, as in the case of a customer who pushes a "button" on their smart thermostat or the Company website to inquire about their charges-to-date. For the customer to maximize their experience with the evolving technology and to understand the actions they need to take to realize the benefits of advanced metering is an important element of a deployment.

Legacy system platforms were not designed to handle real time events such as the ones noted above. They were designed to operate on regularly scheduled cycles of batch processes. From PacifiCorp's perspective, modifying or replacing those old reliable cycle-and-batch systems is a daunting prospect with a large potential for unforeseen challenges that can result in significant cost overruns.

Another challenge that the Company will face is customer outreach, education, recruitment and service levels. In order to retain customer participation, the Company will need to reach out to eligible customers and educate them on the benefits of these programs to maintain a significant rate of participation. This may require the services of a third-party marketing firm or, if done in-house, new software functionality to handle DR recruitment, enrollment, and customer management as well as demand response program management. In addition, utilities will need functionality provided by some meter data management systems (MDMS): management of communications to field devices, tracking of devices and their relationships to customers and premises, and provisioning of devices upon installation. The new software will have to be able to scale, allow multiple users, and interface with the call center, an integrated voice response unit, and the internet. It will also need to interface with the billing system, MDMS, the demand response equipment installation company, and various demand response communication systems.

The Company will also need to re-examine how customer service is provided to customers during deployment and after the advanced metering system is completed. Our call center and web-based customer interaction services will need to be able to effectively work with customers to take advantage of more detailed information on energy use and spending and how to apply it to the customer concerns. This includes performing customer education needed to increase the understanding of smart metering and to reduce the fear and distrust of the changes.

Customer service representatives must also have a strong understanding of the end-to-end business process and changes. Once the systems and processes are implemented, representatives must be prepared to answer and handle a complicated set of questions and issues. This requires representatives to have training and access to the applications and information to provide quality responses.

Metered Data Management

The smart grid results in a paradigm shift regarding metering data. Today, the meter reading system creates monthly files of meter reads and submits them to the billing system. With the smart grid, the Company becomes a de facto communications company that handles millions of data transactions every day. With 1.8 million meters, just the simple transactions involved in the meter-to-cash function are completely transformed. When the numerous other functions are considered (meter provisioning, outage management, demand response events, etc.) the potential enormity of the challenge becomes clear.

To illustrate, every day the advanced metering system operations team must support:

- More than 4,000 meter exchanges per day during deployment
- More than 2,000 customer moves per day (based on 25% yearly turnover)
- 10,000 missing reads per day (99.5% daily read success)
- 20 meter failures per day (0.5% annual failure rate)
- 10,000 data changes per day
- More than 45,000,000 meter reads per day (assuming one-hour interval data)

One certainty about the smart grid is that applications and data uses will evolve and change over time. The solutions to support smart grid initiatives must not only accommodate, but thrive on such change. By planning for the full range of functionality from the beginning and selecting the solutions with the right architecture, the Company can ensure that it not only meets today's broad requirements, but it can also meet the new requirements that will develop down the road.

Distributed Generation

Distributed generation, the installation of photovoltaic systems, fuel cells and other on-site electricity generating systems at customer premises, has the potential to change the dynamics of operating an electrical distribution system. Electrical distribution systems have historically been operated as a "one-way" delivery system moving the required energy from the distribution substation to the end-use customer. As more distributed generation sources appear on the grid, the distribution system must be modified to operate with significant "two-way" energy flows.

Without the appropriate smart grid technologies in place, distributed generation will be a disruptive technology that will impact the distribution system. Standard protection systems, including sectionalizers and fuses, will not be able to provide the proper protection schemes required to maintain the reliability of the system. The smart grid will require the installation of multiple protection devices that have bi-directional measurement capability and built-in analytics allowing them to respond to and isolate faults while protecting the system from stability issues related to end-of-line generation sources. As the number of distributed systems increase, the need for a smart grid will become more evident.

Distributed generation requires that electrical energy is measured in both directions. Energy delivered and energy received by the electric utility must be measured to provide the appropriate billing charges and credits for energy consumed and energy produced by the customer. To accurately measure both quantities, bi-directional metering must be installed at each location where distributed generation systems exist. Meters capable of measuring energy in a bi-directional manner cost significantly more than standard one-way measurement meters.

Plug-In Electric Vehicles

Plug-in electric vehicles are expected to become more widely accepted as the technology advances and the purchase price become more competitive with gasoline vehicles. It is commonly understood that widespread adoption of plug-in electric vehicles will have a large impact on the electrical distribution system. To ensure impacts to the distribution and transmission system or to the customer's home premises wiring can be adequately managed, development of interoperability standards will be required along with necessary changes to electric price tariffs, electric service schedules and building codes. As further introduction of electric vehicles occurs, the whole definition of on-peak and off-peak energy usage will likely change.

Regulatory Considerations

The deployment of a smart grid system introduces several regulatory considerations which must be addressed in order to ensure customers realize the full benefits of the system and that the utility is not penalized as a result of its investment in smart grid technologies or is disincentivized from encouraging its customers to fully utilize the capabilities of the system.

Chief among these considerations is cost recovery of the utility's investment in smart grid technologies. The Company estimates that a smart grid system, as defined in this report, deployed across its six state service territory would cost nearly $1.5 billion. This is a significant investment which would assuredly result in rate increases for customers in all states in which the Company provides service. As discussed previously, the implementation of smart grid deviates from the least cost/adequate service operational model currently employed. While the Company has not fully analyzed customer rate impacts, it is likely that full smart grid deployment would result in higher rates that otherwise would be in effect if smart grid technologies had not been fully deployed. Given this dynamic, it is essential that the Company receive adequate assurance from the states in which smart grid technologies are to be implemented that deployment of smart grid is consistent with the policies of that state. Given the magnitude of smart grid investment, in order to avoid considerable financial harm, the Company should be allowed to recover its prudently incurred costs in the deployment of smart grid technologies.

Related to the concept of cost recovery is how current assets rendered obsolete by the implementation of smart grid technologies are treated. The Company believes that utilities should be allowed to recover the stranded costs of assets rendered obsolete. Otherwise, a utility would be disincentivized from investing in smart grid technologies which would replace assets and systems currently in service as the remaining costs would, in effect, be disallowed rate recovery, resulting in financial harm to the utility.

With the deployment of smart grid, rate structures that place a greater portion of the recovery of fixed costs in non-volumetric charges will be essential. One of the primary intentions of smart grid technologies is to enable both the utility and its customers to reduce peak demand and overall electric energy usage. Rate structures which are designed to recover a significant portion of fixed costs through volumetric energy charges are at odds with the objectives of the smart grid as utilities are typically incentivized to encourage their customers to use more energy, thereby improving the utility's recovery of its fixed costs. With the implementation of smart grid technologies, rate structures which are designed to recover fixed costs through fixed charges will need to be implemented to allow a utility an opportunity to recover its fixed costs (a significant portion of which would be smart grid investment) and to fully realize the peak demand management and energy consumption reduction objectives of the smart grid. It is important to ensure that all investments in smart grid technologies deliver quantifiable benefits and do not artificially increase customer rates.

In addition to rate structures which facilitate the recovery of fixed utility costs, complementary rate structures which encourage customers to use energy more efficiently and at the optimal times during the day will be required with the deployment of smart grid. Smart grid technologies provide the infrastructure by which customers are able to more effectively manage their energy usage, but contribute little towards motivating the customer to use electric energy more efficiently. As discussed in the demand response section of this report, rate designs such as time of use rates, critical peak pricing and peak time rebate structures are a necessary component of smart grid implementation in order to realize the full benefits made available by smart grid technologies.

Smart Grid Economic Review

Each of the components identified for PacifiCorp's smart grid have identified costs and quantifiable benefits that were used to determine the rough potential of investing in those technologies. Whereas there does not exist any proven costs or savings for all of the components, there does exist qualified estimates that can be used to gauge costs and enough theoretical data established for savings opportunities on which a suitable analysis can be built to gauge the relative potential of various alternatives. Many of the benefits are highly variable and dependent on external factors such as values of the forward capacity and energy markets, percentage of the customer base participating in dynamic pricing programs and the energy conservation achieved by those customers. A conservative approach was used in all aspects to protect the integrity of the estimates. As actual and time proven data becomes available, the cost and savings assumptions will be updated to maintain a current assessment of the potential for investment options. Confidential Attachment A provides the Company's smart grid financial analysis summary on a total Company basis.

Benefits and Savings

The benefits of the smart grid can be categorized into two major areas: Company and consumer-based benefits. Company-based benefits are those benefits that are measured as a direct reduction in Company expenses such as operational and system losses. System losses reduce the need for added generation and off-system energy purchases and are generally categorized as generation savings.

Consumer-based benefits are directly attributed to changes in consumer energy-use behavior and are unproven benefits with questionable sustainability. These benefits are expected to occur through pricing structures that encourage both conservation during peak usage hours and changes in usage patterns that result in a shift towards the morning and late evening hours. Without specific time-of-use and critical peak pricing structures, consumers are unlikely to have the incentive to make the behavioral changes required to bring about the benefits of a smart grid. Recommendations or models for time-of-use pricing structures are very complex and will require significant levels of study and debate to arrive at the proper design. Thus, pricing models will remain outside the scope of this report.

Measurement of consumer-based benefits can only be estimated as a reduction in generation requirements and measured by the associated marginal pricing. Additionally, consumer-based benefits could be estimated as a reduction in capital requirements for electrical infrastructure expansion and replacement. However, these savings are only temporary in nature as customer growth drives infrastructure investments.

Many analyses of smart grid benefits categorize some of the savings into "societal benefits" with the caveat that any decrease in outage time, generation or greenhouse gas emissions or other efficiency measures will benefit society as a whole with cleaner air, more reliable electric service, increased production times and other qualitative benefits. These societal benefits are difficult, if not impossible, to quantify with any degree of accuracy and are not included in the Company's analysis of smart grid.

Advanced Metering System (AMS)

The major risks for deploying AMS at this time are vendor selection, home area network protocol and interoperability of components. Additionally, commission approval of new and revised time-varying rate structures and customer participation in these rates is a key component for success.

As with any new technology, employee training and business process changes must occur to gain the expected benefit. Technology specific training has been identified and included within the individual technology cost calculations. Costs for business process changes have not been fully determined but a reasonable estimate was included for an accurate picture of the cost of smart grid. The benefits of the AMS results from the reduction in operating costs associated with manual meter reading, field collections activities and customer call handling resulting from erroneous and estimated meter readings.

Additionally, the costs associated with the accelerated depreciation of the current metering assets will need to be continually calculated and modified as the system is installed. Several areas within PacifiCorp have recently been converted to automated meter reading systems and others may be in the future where practical. The accelerated cost of depreciation for those systems will be higher than in areas with older metering systems. The cost of accelerated depreciation has not been included in this analysis.

Demand Response (DR)

The AMS considered in this analysis is the enabler for a price responsive DR program such as time-of-use (TOU) and critical peak pricing (CPP). A CPP pricing program is implemented with a TOU tariff as a base. A TOU tariff generally has two sets of pricing on a daily basis: the on-peak price per kWh and an off-peak price per kWh. The critical peak hours are usually kept to within four to six hours that coincide with a utility's daily peak demand hours. For PacifiCorp, this would be in the summer during late afternoon and early evening hours.

In addition to the TOU tariff a CPP rider would be included. The CPP rate would be a change to the on peak energy price for the day a critical peak pricing event is called. For the CPP scenarios in this analysis, 10 CPP event days per summer are assumed. Generally, the critical peak days are expected to coincide with heat waves on weekdays, when customer loads are the highest.

In order to give customers time to prepare for the curtailment, CPP event days could be called 24 hours in advance. Notification to customers would be through devices placed in customers' homes and businesses as well as through email, texting and social media channels.

The enactment of TOU and CPP rates structures would require regulatory and/or legislative support in all Company jurisdictions and be supportive of:

1) mandatory TOU and CPP for residential and small commercial customers, and
2) changes in the current manner in which utility costs are recovered. A shift to time-based pricing would require a decoupling of volumetric sales from the recovery of utility costs.

Absent this shift in environment, the benefits assumed in this case for DR are unlikely to be realized. The benefit assumptions would need to be revisited and will likely result in higher costs and lower overall benefits for this investment.

Three scenarios were evaluated to identify one option to include in the economic analysis. The three scenarios include mandatory TOU/CPP, CPP opt-out and CPP opt-in.

For all scenarios, the majority of the load response to CPP events would be from customers with central electric air conditioning and heat pumps. Either through an automated response, or customer manual adjustment, thermostat settings would be raised during CPP events reducing the coincident demand of air conditioning on the system until the event ended. Customers with window air conditioning units could manually adjust their temperature settings as well. Other responses expected would be reducing lighting and plug loads. Customers could also delay operating dish washers, clothes washers, dryers and electric oven/range cooking and turn down electric water heaters manually or with a timer.

In all scenarios, there are ongoing costs such as customer education, CPP event notification and software licensing and/or maintenance. Additional recurring costs include costs associated with load reduction evaluation, customer churn and growth and the replacement of control and notification equipment.

The benefits in each scenario consist of demand and energy reduction during the CPP events, along with the cost of additional energy use (higher than normal) after a CPP event due to loads that are shifted (delaying dishwasher usage and air conditioner take-back) rather than simply reduced (lighting, plug loads).

The benefits quantified include two sources: avoided capacity costs and energy cost savings. The avoided capacity costs represent the avoided peak megawatts multiplied by the expected value of the forward capacity market. The energy costs savings represent the lower cost of purchasing capacity during off-peak hours as compared to on-peak hours.

In developing the assumed response rates, costs and benefits for the three scenarios, it became apparent that the data available on which to base the assumptions and calculations was limited. Participation in nearly all TOU rates for residential and small commercial customers in operation today are voluntary and the data available from smart grid enabled demand response pilot programs, while informative, is insufficient to accurately predict results on a larger scale, across multiple jurisdictions, and in a low retail cost environment.

To maximize the benefits of demand response in this review the costs and benefits of Scenario 1, mandatory TOU with a CPP component, are used. Scenario 1 provided the highest value with the lowest assumed implementation cost and highest assumed demand response from customers. The voluntary nature of Scenarios 2 and 3 increases initial and ongoing marketing costs while in many cases also resulting in diminishing value from participants, many of whom are likely participating because the on-peak and off-peak pricing schedules align closely with normal usage patterns.

Under all three scenarios, the review suggests that if the enabling advanced metering and associated communications were in place, the deployment of demand response on a broader scale than is pursued today would be beneficial. It is important to note that demand response benefits are dependent upon realizing anticipated customer participation rates. And as discussed earlier, PacifiCorp believes insufficient data exists at this time to accurately predict wide spread customer reaction to TOU and CPP rate structures.

Also, adjustments were made to the costs and benefits of demand response for the residential and small commercial load management programs currently in place and operated by PacifiCorp today. The costs of these programs were netted out of the cost and benefits of the broader demand response applications envisioned in a smart grid enabled environment. Whereas demand response is responsible for 72% of the total smart grid benefit, the economic analysis is highly dependent upon the assumptions made for customer participation and retention and future energy costs. Any variance in these assumptions will greatly impact the financial calculations.

Customer Education

There is a very limited amount of experience or data currently available on which to assess the requirements for customer education as advanced metering and smart grid technologies are delivered and customer interaction with the technology increases. To arrive at a suitable estimate for customer education costs, a review of various utility state filings for advanced metering deployment was conducted. Of those filings reviewed, only Oncor Electric Delivery Company's filing included a line item for customer education. Their advanced meter deployment includes a $15.1 million comprehensive customer education program called "SMART TEXAS - rethinking energy" that will educate retail electric customers about the benefits that can be achieved through the use of an advanced meter. Oncor's plan includes a Mobile Experience Center (a hands-on educational tool that will travel throughout Oncor's service territory in advance of the deployment), educational door hangers, and newspaper, billboard and movie theater advertisements.

As we progress in our analysis of smart grid deployment, customer utilization and understanding will be critical to the potential for success. We firmly believe that better understanding customer expectations and motivations will be critical, as will ensuring that adequate resources are identified to perform outreach and education. These changes also could dramatically transform our backoffice functions, including personnel, training and the tools necessary to meet customer expectations.

Distribution Management Systems (DMS)

Both Pacific Power and Rocky Mountain Power have a history of managing their distribution systems for optimal power factor and voltage profile, reduced line losses and increased system efficiency. This attention to managing the distribution system has resulted in the installation of numerous capacitor banks and voltage regulators over the lifetime of the distribution system. This proactive program of managing distribution efficiencies has mitigated the total savings that could be obtained with an advanced distribution management system, including IVVO and CVR programs. Costs to migrate to smart grid have been mitigated as well as the existing line equipment will only require the control panel be upgraded to allow for the required two-way communications.

In addition to the existing line equipment and to create a smoother, leveled voltage profile, additional capacitor banks would be installed and controlled by the DMS. These additional voltage regulators and capacitor banks may, to a minor extent, further reduce the line losses on the system resulting in less required generation. However, the resultant decrease may be immeasurable as the energy savings is so small that it falls within the normal range of load fluctuation. The ability for the capacitor banks to automatically report malfunctions will reduce field level inspections and costs.

The addition of fault circuit indicators and automated field switching devices will provide for additional operational benefits from reduced capacitor inspections and reductions in manual switching orders. The ability to proactively respond to outages on the system will provide operational benefits in the form of reduced outage calls to the call center, a reduction in the number trouble tickets issued and better management of field crews during the outage.

Attachment A is confidential
and provided under separate cover