PacifiCorp
A MidAmerican Energy Holdings Company

# Smart Grid Annual Report

**July 12, 2013**

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## Executive Summary

The smart grid began as a loosely defined concept but has come to refer to a variety of advanced technologies and equipment used by utilities and their customers. In general the smart grid is a system of communications networks coupled with automated control of the power grid and end-use devices, along with enhanced customer awareness of their electricity use and its impact. For PacifiCorp the smart grid definition started with a review of relevant technologies for transmission, substation and distribution systems, as well as smart metering and home area networks which enable consumer response to such system inputs as price fluctuations and load curtailment requests. A review of the interoperation of these technologies showed that the most critical infrastructure decision to be made during smart grid design is the communications network. The network must be high-speed, secure and highly reliable and must be scalable to support PacifiCorp's entire service territory. The network must accommodate both normal and emergency operation of the electrical system and be available at all times, especially during the first critical moments of a large scale disturbance to the system.

This smart grid report focuses on technologies that do not require major electrical system changes and can be readily integrated with the existing infrastructure. The technologies chosen for the study were narrowed down to advanced metering systems (AMS) with demand response (DR) programs, distribution management systems and transmission synchrophasors. Technologies included in the study but not considered in the financial analysis include fully redundant ("self-healing") distribution systems, distributed energy systems (including electric vehicles) and direct load control programs.

Each of the components examined have quantifiable costs and benefits that were used to estimate the rough potential of investing in those technologies. While there are not always proven costs or savings for each of the components, qualified estimates can be used to gauge costs when there is enough theoretical data established for savings opportunities.  A suitable analysis can then be built to gauge the relative potential of feasible alternatives. Many of the benefits are highly variable and dependent on external factors, especially factors that involve changes in consumer behavior, values of the forward capacity and energy markets, certain percentages of the customer base participating in dynamic pricing programs and the energy conservation achieved by those customers. All of the cost and savings data presented contain the most reliable data available at the time of publication.

The net present value of implementing a comprehensive smart grid system throughout PacifiCorp's territory is negative at this time. However, many smart grid technologies are showing promise for future improvements in the operation and management of transmission and distribution systems. Modification of consumer behavior would be central to realizing many benefits, since changes in usage and improved conservation have the potential to dramatically transform the electric industry. However, the ability to sustain any consumer behavior change remains uncertain.

In order to mitigate the costs and risks to the Company and its customers it is essential that technology leaders be identified and system interoperability and security issues be verified and resolved with national standards. PacifiCorp will continue to monitor technological advances and utility developments 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. With large scale deployments progressing throughout the country, it is expected that the smart grid market leaders will become evident within the next few years. Demonstration projects will reveal the sustainability of large-scale rollouts and give utilities a better idea of which areas of the smart grid are best suited for implementation on their systems.

## Smart Grid Strategies, Objectives and Goals

The purpose of this smart grid report is to define the scope and philosophy of the smart grid for PacifiCorp, identify the strategies, objectives and goals required to meet that definition and examine the financial characteristics required of an investment that would attain these goals. A road map for the future is presented at the end of the report which aligns the relative start dates for various system components in order to give a better understanding of the progress required to reach a full smart grid with an aggressive schedule. The starting date and progression schedule of any smart grid effort must be driven by the fundamental economics to protect the Company and customers' best interests.

PacifiCorp considers the following strategies as necessary to realizing a smart-grid:

- Ensure that smart grid investments support providing adequate service at reasonable and fair prices by comparing products and solution configurations in a financial model that highlights the most beneficial solution configurations
- Institute cost-effective standards and equipment specifications that enable implementation of smart-grid compatible devices, either through retrofitting where appropriate or through replacement due to equipment obsolescence or failure
- Meet with manufacturers to discuss smart-grid products and their applicability to PacifiCorp's system
- Research industry projects and events and apply this knowledge to PacifiCorp's benefit

The smart grid department adheres to the foregoing strategies and maintains a knowledge database that is available for internal stakeholders' use when researching potential smart grid projects. The smart grid team also works with other internal departments to ensure that these strategies are being respected as projects progress.

A number of short-term objectives have been drafted as part of the smart grid drive at PacifiCorp:

- Continually improve customer relations through web portal work and customer communications
- Draft an advanced meter solution for Oregon by the end of 2014
- Implement a custom meter data management system that is capable of handling smart-grid levels of data throughput by the end of 2014

These strategies and objectives are the tools by which the Company expects to be able to reach its long-term smart grid goals, which include:

- Increasing customer awareness and understanding of how the electric system works, how electricity usage impacts and drives Company investments and operations
- Giving customers tools they can use to change their electricity usage in ways that benefit themselves and society as a whole
- Optimizing PacifiCorp's electric system through the application of cost-effective smart-grid technologies

It is PacifiCorp's goal to leverage smart grid technologies to optimize the electrical grid when and where it is economically feasible, operationally beneficial and in the best interest of customers.

## The Smart Grid – An Introduction

Electric utility companies are involved in an evolution of advanced sensing and communicating technologies and traditional operational practices. The technologies associated with advanced power grids 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 grids expands across the country.

Both the EPAct and the EISA required that all states review the text of the legislation and make a determination of whether or not to adopt the standards included within. While each of the states within PacifiCorp's service territory have elected not to adopt most of the standards a number have voiced an interest in understanding what the Company's current and future plans are for implementing smart grid technologies.

The interest in smart grid at the regulatory level has also grown due to the marketing efforts of companies positioned to take advantage of the investments funded by the ARRA legislation. Inquiries into the Company's ability to build out 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.

The purpose of this document is to define the scope of smart grid for PacifiCorp, identify the technologies that would be required to meet the scope definition and examine the financial characteristics of such an investment. This document will not provide a recommendation for regulatory strategies nor include a consideration for the replacement of the current customer information systems (although it is imperative to a fully realized smart grid system that it be replaced). It is designed to provide the reader with a basic understanding of the smart grid definition and components, along with their costs and benefits. This document does not provide a detailed level of understanding or an ideological explanation of the finite details behind every technology that can be used to migrate to a smart grid throughout PacifiCorp's system. A road map for the future is presented which aligns the relative start dates for various system components in order to give the reader a better understanding of the progress required to reach a full smart grid with an aggressive schedule. The starting date and progression schedule of any smart grid effort must be driven by the fundamental economics to protect the Company and its customers' best interests.

The following definitions are presented as a fundamental baseline upon which to define PacifiCorp's smart grid. These concepts will be used to qualify components and goals of the smart grid throughout this report.

The Electric Power Research Institute (EPRI) defines the power system architecture of the future as[1]:

- A power system made up of numerous automated transmission and distribution systems, all operating in a coordinated, efficient and reliable manner,
- A power system that handles emergency conditions with 'self-healing' actions and is responsive to energy – both market and utility needs, and
- A power system that serves millions of customers and has an intelligent communications infrastructure enabling the timely, secure, and adaptable information flow needed to provide power to the evolving digital economy.

According to the Modern Grid Initiative, a smart grid has the following characteristics:

- "It will enable participation by consumers." Smart grid enables consumers to have access to new information, control, and options to engage in electricity markets. Consumers will be able to see what they use, when they use it, and what it costs them. This will enable them to manage their energy costs, invest in new devices and sell resources for revenue or environmental stewardship. In addition, grid operators will have new resource options that will enable them to reduce peak load and prices and improve reliability.
- "It will accommodate all generation and storage options." Smart grid will seamlessly integrate all types and sizes of electrical generation and storage systems. This will move the system from one dominated by central generation to a more decentralized model as more smaller distributed sources and plug-and-play convenience come into the system.
- "It will enable new products, services and markets." Smart grid will link buyers and sellers, support the creation of new electricity markets, and provide for consistent market operation across regions. That is, instead of the current poorly integrated, limited wholesale markets, smart grid will lead to mature, well-integrated wholesale markets and growth of new electricity markets.
- "It will provide power quality for the digital economy." The smart grid will provide utilities with the ability to better monitor, diagnose, and respond to power quality issues, thus reducing consumer losses due to poor power quality.
- "It will optimize asset utilization and operate efficiently." Smart grid will enhance asset operations by improving load data, reducing system losses, and integrating outage management. It will also improve the maintenance and resource management processes. This will lead to reduced utility costs, both O&M and capital.
- "It will anticipate and respond to system disturbances." With smart grid, the system will be able to self-heal by performing continuous self-assessment, detecting, analyzing, and responding to any disturbances, and restoring the grid components or network sections.

[1] http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001012160

- “It will operate resiliently against attack and natural disaster.” Smart grid enables system-wide solutions to physical and cyber security issues, thereby reducing threats and vulnerabilities.

**Regulatory Framework**

In August 2005, Congress passed the EPAct, in which Section 1252, entitled “Smart Metering,” laid the framework for time-based pricing for electrical energy consumption. This bill required that each regulated utility offer time-based rates and each state commission investigate DR and time-based metering. All states served by PacifiCorp have reviewed and responded to the EPAct, as required, with no significant effect on the Company’s metering systems or operational standards.

On December 19, 2007, the EISA was passed and ushered in a new era in the policy decisions of state regulation commissions as well as electric utility companies within their jurisdictions. The EISA is applicable to all electric utility companies, whether investor-owned, public or municipal. The policy statement contained in Section 1301 of the EISA, “Statement of Policy on Modernization of Electricity Grid,” has broad implications that will affect all utilities and their decisions regarding the deployment of automated metering, advanced metering and smart metering technologies.

Section 1301 defines the smart grid and, indirectly, smart metering. It is more inclusive than the definition of smart metering found in Section 1252 of the EPAct. Section 1301 of the EISA defines the smart grid as “the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a smart grid:

> (1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
> (2) Dynamic optimization of grid operations and resources, with full cyber-security.
> (3) Deployment and integration of distributed resources and generation, including renewable resources.
> (4) Development and incorporation of DR, demand-side resources, and energy-efficiency resources.
> (5) Deployment of ‘smart’ technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
> (6) Integration of ‘smart’ appliances and consumer devices.

(7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
(8) Provision to consumers of timely information and control options.
(9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
(10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

To meet the intent of these generally accepted definitions of a smart grid it can be deduced that intelligent electronic devices (IEDs) must be placed on every critical node of the end-to-end grid. It can also be concluded that a smart grid must have a robust, reliable, and secure communication network throughout the grid as well. Thus, to achieve a smart grid, the Company must merge the electricity generation and delivery infrastructure with the information and communication infrastructure.

## Components of the Smart Grid

PacifiCorp began defining the smart grid with a review of relevant technologies for transmission, substation and distribution systems, including smart metering and home area networks. As the Company reviewed these technologies it 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. The communication network must be available at all times, including the first critical moments of a large scale disturbance to the system.

There are several broad categories within the smart grid whose benefits and functions remain relatively undefined. For example, distribution automation is made up of several functionalities that have intelligent interoperability among themselves to enable efficiency and reliability optimization of the system. Over-sizing and redundancy will be required of a system that can locate and isolate faulted conductors and automatically restore power to areas outside fault zones, as well as increase efficiency through integrated renewable and distributed generation resources, improve system balancing and actively manage power factor and line losses. A fully redundant system is required to enable the complete spectrum of distribution automation. This level of redundancy comes at a cost that will not support any economy-based decision. Therefore, fully redundant systems are not included as part of this report.

The focus for this report will remain on those technologies that are easily integrated into the existing infrastructure, i.e., 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 below. Each of these components utilizes a common information technology and communications infrastructure to gain maximum benefit through reduced duplication of facilities. Technologies included in the study but not considered in the financial analysis include fully redundant ("self-healing") distribution systems, distributed energy systems (including electric vehicles) and direct load control programs. The Company will continue to explore these technologies and will include them in future analyses when their benefits become more mainstream and quantifiable.

With the large capital investment required to enable these smart grid elements, it is essential that the market leaders be identified and system interoperability be verified. With deployments growing throughout North America, most notably including California, Texas and Ontario and a myriad of pilots enabled through the recent ARRA funding opportunities, the market leaders will become evident as the systems begin to mature over the next few years.

| |
|---|
| <u>Technology Component</u> |
| 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 – Studied Technology Components**

## Information and Communication Infrastructure

Information and communication infrastructures are the backbone of the smart grid and are critical to the success of the program[2]. The system must be robust enough to handle the amount of data generated by the AMS and the IEDs deployed throughout the electricity delivery infrastructure; in addition the system must have the intelligence to prioritize and react to the data delivered. Information related to system disturbances or outages must be given preferential handling over lower priority items such as meter reads. The information technology system must process the data and interpret which applications need the data and in which format. It must be able to store the data in an easily retrievable, archived format and utilize that data for historical and comparative purposes. This data can then be utilized when corrective actions are needed in order to efficiently manage the electricity delivery infrastructure.

Figure 1 illustrates the smart grid information and communications architecture that must be developed to implement the entire scope of the PacifiCorp smart grid[3].

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[2]U. S. Department of Energy, Office of Electricity Delivery and Energy Reliability**,** Recovery Act Financial Assistance Funding Opportunity Announcement, Smart Grid Investment Grant Program, DE-FOA-0000058, June 25, 2009.
[3] Transmission synchrophasors are not part of the model, since 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 phasor measurement units.

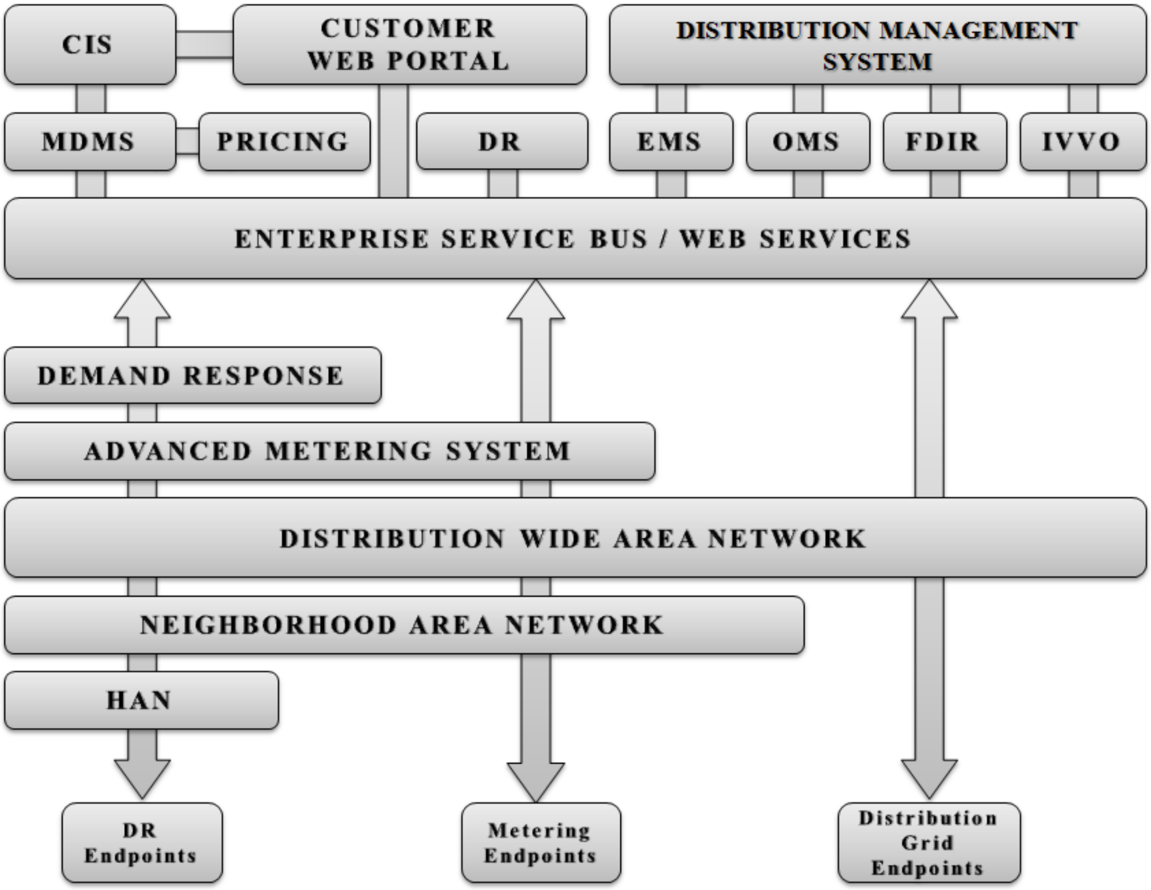


**Figure 1 – PacifiCorp Smart Grid Architecture**

## Communications Network

A key component 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 diverse geography of PacifiCorp's service territory and low customer density, dictates an extensive, complex and ultimately costly smart grid communications network.

The purpose of a smart grid is to provide improved efficiencies in the production, transport, and delivery of energy, which can be 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 require more measurement points, remote monitoring and management capabilities than exist today. Greater reliance on reliable, robust and highly available communications is also required.

The new smart applications are dictating the need for a wider deployment of communications through the distribution circuits, 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 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 reusing the existing fiber and microwave systems where possible but expanding it significantly to support other services. New wide area networks (WANs) will need to be built out or leased in order to support customer and distribution assets.

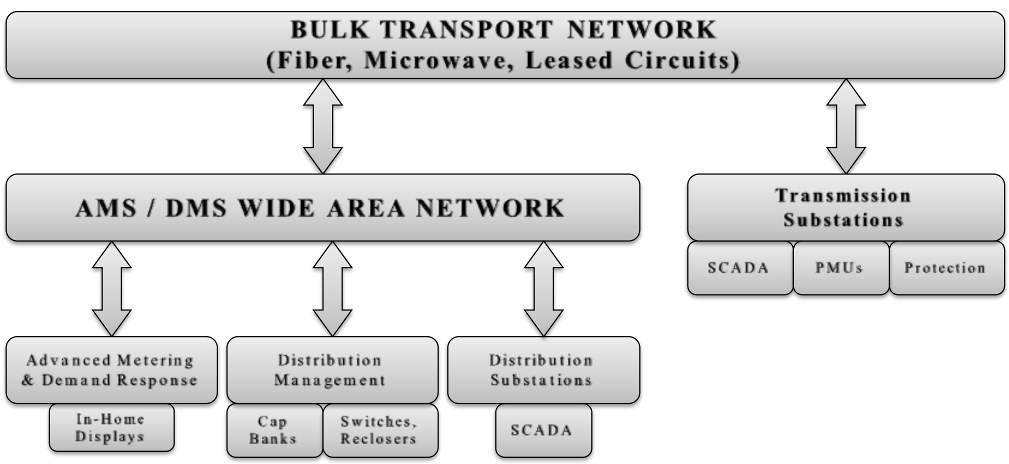


**Figure 2 – Smart Grid Communications Network**

The vision is to efficiently leverage the long-haul communication assets currently deployed and avoid creating silos of purpose-built networks. The key is to guarantee that 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[4] that is being developed by the National Institute of Standards and Technology (NIST).

## Advanced Metering Systems

An AMS provides the highest level of meter reading automation, satisfies all requirements for a smart grid system and provides the data required to fully integrate meter reading, DR, outage management, and distribution management functions. These systems have the capability to offer to customers an in-home display of energy use related information and enable direct load control, wherein the utility sends signals to cycle specific loads (e.g. A/C, water heaters, pool pumps). These systems are also capable of integrating indirect load control, wherein the utility sends pricing signals and consumers can program the behavior of individual appliances or adjust energy usage patterns to respond to changing prices.

Advanced metering infrastructures (AMIs) provide the same metering data levels as automated meter reading (AMR), or drive-by systems, but they provide enhanced capabilities by remotely collecting data from all meters. This functionality can be used for time-based rates and critical peak pricing programs but lacks the direct customer notification and integration of in-home displays. AMI systems can provide additional benefits in the form of outage detection and restoration messages. DR programs cannot be implemented directly through most AMI systems and must be implemented with direct load control through a separate system (such as paging) and the impacts are then 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."[5,6]

Neither home area networks nor in-home displays are a required component of AMI as defined by FERC, although they offer benefits for DR in addition to those made possible with AMI-supported time-varying pricing alone. Also, control of distribution equipment (reclosers,

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[4] NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0 NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0

[5] http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

[6] http://www.ferc.gov/industries/electric/indus-act/demand-response/2008/survey/glossary.pdf

sectionalizers, capacitors, etc.) is not a required component of AMI. Combined with an AMI, these additional features begin to lay the framework for a smart grid.

AMR is 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 have been the most commonly implemented AMR 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[7].

The term AMI is routinely used 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 AMS. The functional requirements of the metering system must be known in order to determine the reasonableness of the system proposed. 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 paper, 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. AMR systems and most AMIs cannot be migrated to an advanced metering system without significant costs.

## Demand Response

One of the key requirements to encourage customers to change energy usage patterns is to send proper pricing signals. The most common price signals in the industry today are time-of-use (TOU), critical peak pricing (CPP) or critical peak rebate (CPR) programs[8]. A combination of TOU/CPP or TOU/CPR pricing programs are the most prevalent, and, designed and positioned appropriately, can present opportunities for creating reductions in energy usage during critical periods when system peaks are present.

TOU tariffs create pricing programs that present to the consumer a proxy for real-time or relative prices of energy at various times during the day. By selling electrical energy at the real-time price it is anticipated that some consumers would shift their consumption from the peak periods, and thus 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.

[7] http://www.ferc.gov/eventcalendar/Files/20070423091846-EPRI%20-%20Advanced%20Metering.pdf
[8] http://www.smartgrid.gov/recovery_act/deployment_status/time_based_rate_programs

In comparison, critical peak pricing schemes are typically 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 in the summer months) increases dramatically at the end of the CPP event in an effort to bring customers' residences back to a "normal" comfort state. If the CPP event occurs for an extended period of time and sufficient participation occurs in shifting usage outside of the CPP event window, the rebound effect becomes more pronounced and can create a new daily system peak, potentially higher than what the normal peak may have been. This is an anomaly that can exist, but there have been insufficient studies to calculate the magnitude and overall system effect with any dependable degree of accuracy.

It has been stated that, given the proper pricing signals, a percentage of 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[9]. Thus, there is no history that would allow PacifiCorp to predict how much load can be reduced by and for how long customers will voluntarily participate in a dynamic pricing program.

PacifiCorp Peak Demand

The PacifiCorp summer peak of 2012 was measured at 9,831 megawatts on July 12. System daily peaks for this time period are shown in Figure 3. This historical data can be used to determine timing and pricing for future periods, although in reality the ability to forecast the exact time periods of critical peak events is not possible.

[9] http://www.smartgrid.gov/recovery_act/program_impacts/consumer_behavior_studies

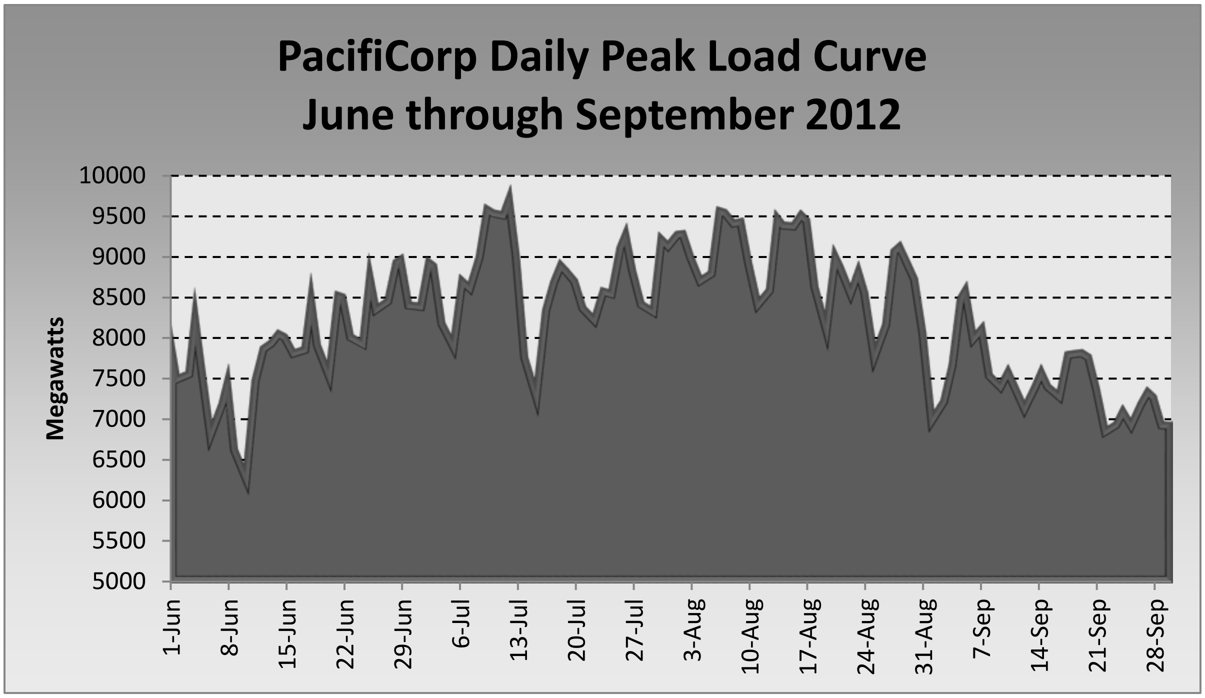


**Figure 3 – PacifiCorp Daily Peak Load Curve**

PacifiCorp has provided a comprehensive set of demand-side management programs to its customers since the 1970s in an effort 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 participation in these programs is voluntary and relies on site-specific control equipment and communication protocols for controlling loads, as of 2012 PacifiCorp has built a control network of participating customer end use loads of over 600 megawatts.[10] 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 by employing education, equipment, and price incentives to optimize system performance.

In addition to direct load management programs, PacifiCorp also employs time-variant pricing schedules, both voluntary and mandatory, to assist in managing peak usage and reduce system

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[10] PacifiCorp's 2013 Integrated Resource Plan, April, 2013, Chapter 5, Table 5.10 – Existing DSM Summary 2013-2022. http://eportal.pacificorp.us/irj/portal

costs. PacifiCorp has several rate structures currently in place to help manage customer usage. These include inverted block structures for residential customers and time-of-use (TOU) and/or time-of-day (TOD) structures for residential, commercial, industrial and irrigation customers.

The residential inverted block structures increase the rate for energy as usage increases. These rates are mandatory for all customers in all of PacifiCorp's six jurisdictions. The usage block structure varies by jurisdiction with increasing prices starting at 400 kWh per month in Utah to 1,000 kWh per month in Oregon. Utah has a second price tier that starts at 1,000 kWh per month while California's incremental tier varies by season, county and whether the customer has electric heat.

The incremental price also varies by jurisdiction. In California, the highest block price is approximately 20 percent higher than the base price while in Wyoming the highest block price is more than 100 percent higher than the base price. In other jurisdictions the top block price is 30-50 percent higher than the base price. The combination of the incremental price difference and the amount of consumption in the top tier drives the overall impact of the block rate structure on usage.

Residential TOU rates have predominately been subscribed to in Idaho, with limited participation in Oregon and Utah. The TOU rates vary by season in Oregon and Idaho. In Utah the TOU rates are applicable only in the summer months.

The commercial, industrial and irrigation TOU and TOD rates are a combination of voluntary and mandatory rates depending on the jurisdiction and size of the customer, as defined by peak demand. The rates also vary in complexity. Some of the rates vary time of use, while others add a demand surcharge for on-peak use. The rates also vary by season.

The impacts of these rates were recently estimated using price elasticity metrics[11]. Price elasticity measures either the reduction in use due to an increase in price (own-price elasticity) or a shift in usage from peak to off-peak usage due to different prices at different periods (cross-price elasticity).

Table 2 is a summary of Price Schedules by State and shows current levels of participation in voluntary programs.

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11 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_FINAL_Vol%20I.pdf.

| Description | State (Schedule) | Participating customers (Dec. 31, 2012) | Eligible customers (includes participating) | Percent of eligible customers participating | Voluntary/ Mandatory |
|---|---|---|---|---|---|
| Residential time-of-use or time-of-day pricing(optional) | Utah (Sch. 2) | 347 | 714,722 | 0.05 | Voluntary |
| | Oregon (Sch. 4/210) | 1,229 | 475,853 | 0.26 | Voluntary |
| | Idaho (Sch. 36) | 13,994 | 57,931 | 24.16 | Voluntary |
| General service (business sector and irrigation) time-of-use and time-of-day pricing, either energy or demand (combination of mandatory and optional) | Washington | 1 | 1 | 100 | Mandatory |
| | Washington (Sch,48T) | 60 | 60 | 100 | Mandatory |
| | California (Sch. AT48) | 19 | 19 | 100 | Mandatory |
| | Idaho (Sch. 35/35A) | 4 | 10,023 | 0.04 | Voluntary |
| | Wyoming (Sch.33) | 8 | 8 | 100 | Mandatory |
| | Wyoming (Sch.46) | 80 | 80 | 100 | Mandatory |
| | Wyoming (Sch.48T) | 27 | 27 | 100 | Mandatory |
| | Utah (Sch. 6A / 6B) | 2,215 | 107,171 | 2.07 | Voluntary |
| | Utah (Sch. 8) | 268 | 268 | 100 | Mandatory |
| | Utah (Sch. 9 / 9A) | 159 | 159 | 100 | Mandatory |
| | Utah (Sch. 10/TOD [1] | 245 | 2,916 | 8.40 | Voluntary |
| | Utah (Sch. 31) | 4 | 4 | 100 | Mandatory |
| | Oregon (Sch. 23 / 210) | 274 | 75,157 | 0.36 | Voluntary |
| | Oregon (Sch. 41 / 210) | 58 | 6,097 | 0.95 | Voluntary |
| | Oregon (Sch. 47) | 7 | 7 | 100 | Mandatory |
| | Oregon (Sch. 48) | 202 | 202 | 100 | Mandatory |

**Table 2 – Summary of Price Schedules by State**

It is important to account for existing DR program loads and benefits in smart-grid business case efforts in order to avoid overestimating those benefits. The current residential air conditioning control program load reductions have been accounted for in the study; however, a detailed study of the pricing impacts in absence of this program has not been completed.

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

## Home Area Networks (HANs)

In the context of smart grid, the term “Home Area Network” has become synonymous with in-home displays and programmable communicating thermostats. Each of these devices serves a different level of functionality, enabling the consumer to have 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 electrical 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 the HAN. In-home displays range from simple plug-in and battery operated in-home displays equipped with three levels of indication via green, yellow and red lights, to very sophisticated displays that interface with customers' HANs. Home area networks enable the customer to leverage the real-time information received via the AMS into automated actionable tasks that can reduce their energy consumption at peak times as well as enabling other forms of energy conservation. The AMS transmits 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 HAN, more sophisticated communicating devices are required to allow the customer to program automatic actions to pricing signals and critical peak events. HANs coupled with automated home appliances can give individuals more control over their electricity consumption.

## Distribution Management System (DMS)

Greater precision in operational data and minute-by-minute management is critical to long-term success as distribution systems become more sophisticated. A DMS provides the utility with a variety of advanced analytical and operational tools for managing complex distribution systems and integrates several systems and functions that are currently operated independently, specifically:

- Outage management
- Switching operations
- Lock-out and tagging procedures
- Fault calculations
- Load flows
- Real-time state estimation routines

When integrated with an Interactive Volt-Var Optimization (IVVO) functionality the DMS can manage voltages to minimize line losses and energy needs while optimizing the delivery of power 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 in turn control remote equipment which helps increase the efficiency of the system.

A DMS creates 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 DMS provides distribution engineers with near real-time system performance data and highly granular historical performance metrics. This decreases planning time requirements, increases visibility of the system status and improves reliability metrics through better application and management of the distribution capital budgets. A generic schematic of a smart grid DMS is shown in Figure 4.

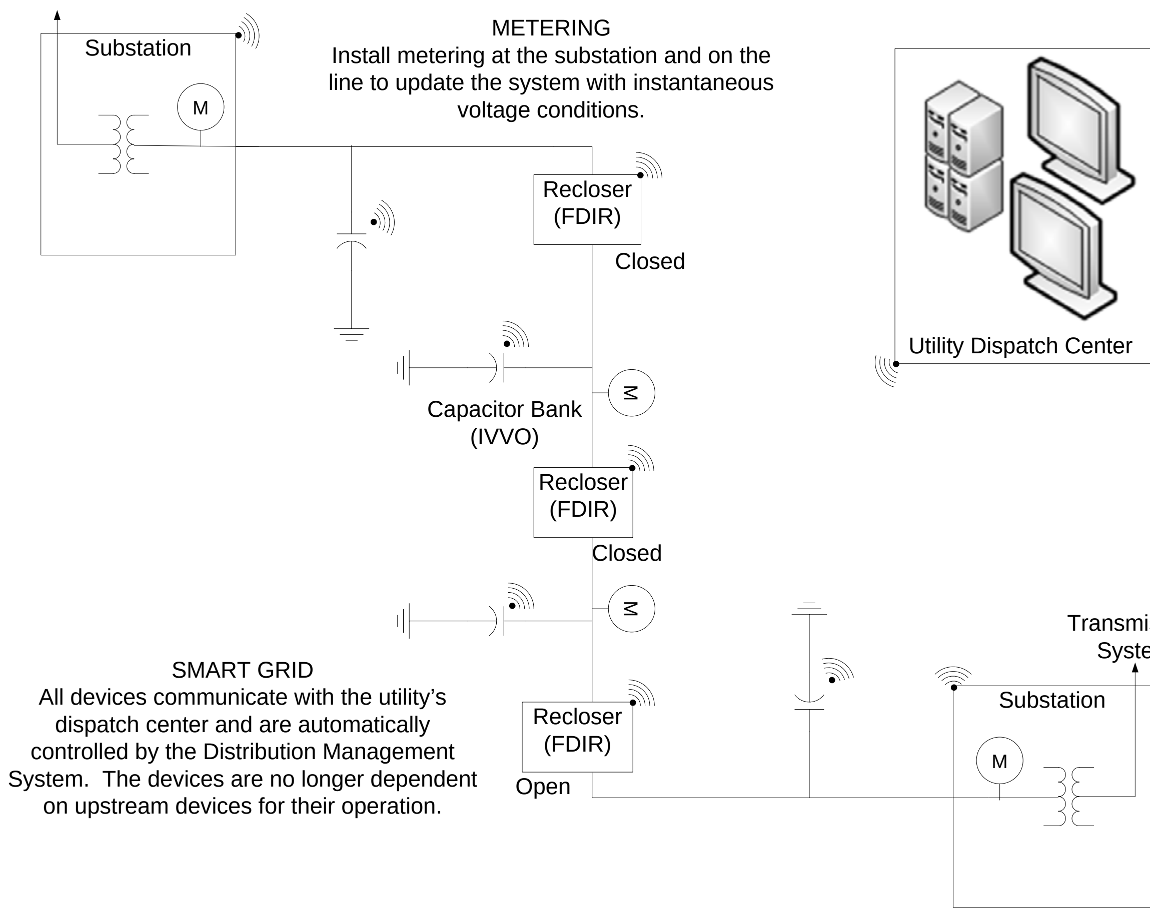


**Figure 4 – Generic Distribution Management System**

With appropriate data inputs from field IEDs the DMS will be able to analyze the distribution network for both normal and emergency states and perform the following functions required for IVVO and FDIR:

- Monitor unbalanced load flow and determine if there are any operational violations for normal state and reconfigured distribution feeders.
- Determine the optimal positions and operating constraints for the various power transformer taps, line voltage regulators and capacitors along a distribution feeder and manage the open/closed positions of these devices.
- Receive fault data and run a short circuit analysis to determine the probable location(s) of faults.
- Analyze the system during faulted conditions and determine the optimal redistribution of 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 implementation of IVVO or FDIR 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 DMS that will incorporate the emerging technologies for a smart grid.

<u>Interactive Volt-Var Optimization (IVVO)</u>

As established by American National Standards Institute (ANSI) Standard C84.1, allowable voltage values at the point of service under normal operating conditions include a range around a nominal value[12]. For standard residential delivery the ANSI A range voltage on a 120 volt scale spans from 114 to 126 volts (± 5 percent from nominal). For primary metered customers, the ANSI A range voltage on a 120 volt scale spans from 117 to 126 volts.

To maintain the voltage within the specified range across the entire distribution circuit the voltage at the distribution substation bus is controlled by some combination of a load tap changer (LTC), substation regulator(s) and substation capacitor(s). Features inherent in each device facilitate the utility's voltage management under all loading conditions so that acceptable voltage levels are maintained for all customers. The circuit's voltage generally degrades as a function of

[12] ANSI C84.1-2011, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz), p. 3, p. 8

line length, impedance and loading, and, if not properly managed, can degrade to levels below the allowable ANSI limit. To keep service voltages within the allowable range, system improvements such as phase balancing, reconductoring and the addition of capacitor banks and voltage regulators are often employed. Their purpose is to ensure that the service voltage to all customers is maintained within ANSI A range under normal operating conditions.

The decision of which device to install is driven by the characteristics of the circuit at the point of application. The engineering considerations and design parameters used for this decision are complex and will not be discussed in detail other than to state that installation and operation costs, power factor, voltage levels and loading profiles must be considered.

An IVVO program utilizes strategically placed distribution voltage regulators and capacitor banks to manage voltages and power factor, as well as reduce line losses. With coordination between devices via modern firmware and communications, regulator and capacitor behavior can be adjusted to achieve such goals as: optimized voltage, optimized power factor, demand shifting or energy reduction. Operators may select the appropriate goal in real-time via a module in the DMS.

Downstream device behavior in a traditional distribution system is contingent upon upstream devices and pre-programmed operational parameters. As the penetration of distributed generation sources increases, historically adequate voltage and power factor management schemes must be updated in order to maintain satisfactory voltage levels. The DMS actively manages the voltage levels and power factor and adjusts the line devices independently to optimize the voltage profile across the distribution system. This optimized voltage profile and visibility into system behavior is only achievable through the complete integration of direct communication with the field equipment and the algorithms in the DMS. By more actively managing voltage and power factor a utility can better regulate its voltage profiles on each circuit. Real-time optimization of voltage and power factor decreases line losses across the distribution system, thereby increasing system efficiency.

### Conservation Voltage Reduction (CVR)

For circuits whose load is primarily resistive (typical of residential loads), a lower distribution voltage can reduce system energy and demand. A utility that operates in the upper portion of the allowed ANSI voltage range may be able to reduce system loading and losses during select conditions by lowering its service voltages to the lower portion of ANSI Range A.

Utilities with an IVVO system already in place can achieve CVR by setting a voltage reduction priority in its DMS control module. The more efficiently a utility's circuit is designed the greater its flexibility in achieving the selected goal. A CVR module may use an AMS to obtain delivery voltage information from selected metering points along the circuit. The module then minimizes the system voltage by signaling the operation of capacitor banks and regulators according to its algorithms. This aggregate reduction in service voltage reduces load current, demand and energy.

A utility without an IVVO system can implement a simplified CVR strategy. Improvements are generally implemented to reduce primary voltage drop, correct current and voltage unbalance, meet power factor guidelines and match voltage drop behavior between multiple circuits regulated by the same device. Engineering analysis then provides the optimum device settings to achieve the lowest average delivery voltage under all operating conditions. Some metering improvements may be necessary to ensure system response meets expectations. Ongoing analysis and occasional settings adjustments may be required and visibility of system behavior towards target may be limited.

PacifiCorp has identified several potential risks of CVR and IVVO implementation, based on recent industry research and utility pilots[13]:

- Increased number of residential customer complaints due to low voltage. Examples include malfunctioning equipment, dim lights, shrunken TV screens and longer duty cycles for constant energy appliances like resistive heaters and clothes dryers.
- Increased number of commercial and industrial customer complaints due to low voltage. Examples include increased exposure of sensitive customer equipment (like computer-controlled laboratory and hospital equipment, tools and motors) to voltage sags and nuisance tripping, as well as expensive down-time affecting profitability.
- PacifiCorp's historical voltage control settings yield little room for voltage reduction, which in turn generates small energy savings relative to many other utilities where high voltage control settings have been in place.
- PacifiCorp's own cost-benefit analysis determined that only minimal improvements, such as phase balancing, are cost effective in many cases. The additional savings provided by capital improvements, such as the addition of line regulators and capacitors, most often are not cost-justified.
- Accurate measurement and verification of the energy savings achieved is problematic. Time-series voltage data at each delivery point is generally not available, so estimated delivery voltages must be used. The energy response to reduced voltage is different for each customer at any point in time. The response for any given customer also varies over time as habits and end-use appliances change. The aggregated system response must be estimated to determine the total energy savings achieved year by year. Each of these

1. [13] An Exploration of Dynamic Conservation Voltage Control, Hataway, Jacobsen and Donolo; https://www.selinc.com/WorkArea/DownloadAsset.aspx?id=99373, p 5

elements introduces error to the measurement and verification effort, and consideration of the total error can undermine a project's cost-effectiveness.

It is imperative that the IVVO/CVR system respond quickly to substandard voltage conditions to prevent unintended consequences and operational problems for customers' equipment. It is also critical that industry leaders arrive at a consensus for accurate, low-cost measurement and verification methods for project justification and post-implementation reporting.

### Capacitor Bank Maintenance

Capacitor banks are visually inspected typically once per year for damaged tanks or blown fuses and to determine their operational state. If the capacitor bank fails or becomes inoperable between inspections, the benefits of the IVVO system and the individual capacitor banks will not be realized. An IVVO system's reporting capabilities can detect when a capacitor bank has operational problems without requiring manual inspection, which reduces the cost of annual inspection work. When a problem is detected the module can create a trouble order, thereby reducing the time the bank is out of service and maximizing the benefits of the voltage and VAR optimization routines.

### Centralized Energy Storage (CES)

One of the benefits of the 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 random or variable. If a significant percentage of energy generation comes from these variable sources the grid will not be able to deliver the required power when the renewable energy source is not available. There are two primary ways to fill this generation gap without the use of fossil fuel: DR programs and CES.

CES can be used to store utility scale wind or solar generated energy (which typically occurs at non-peak hours) and release that energy during peak hours. Energy storage can also potentially benefit the transmission and distribution (T&D) system by alleviating daily congestion patterns by storing energy until the transmission system is capable of delivering it where needed. Several new technologies are currently being researched throughout the industry, including battery, pumped hydro, flywheel and compressed air energy storage. Each of these solutions has unique characteristics, benefits, applications and costs.

In contrast to the single cell rechargeable batteries used in cell phones and other small appliances, electrical battery storage for utility-scale applications require energy levels that can only be produced by converting chemical energy to electrical energy. Lithium-ion batteries have the highest power density of all advanced batteries on the commercial market. They are more common in small applications, but building large-scale lithium-ion batteries remains prohibitively expensive[14]. 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 potential for large scale applications. For utility-scale applications, nickel-cadmium batteries have gained a reputation as a rugged, durable stored energy source with good cycling capability and a broad discharge range. Some cutting-edge solutions aggregate a multitude of small batteries, such as those found in electric vehicles and uninterruptible power supplies.

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 upgrades in substation power transformers, which overload only during short periods and at peak hours of the year. For the purposes of PacifiCorp's smart grid, this study uses battery storage for the centralized energy storage cost and benefit analysis.

PacifiCorp analyzed various CES systems to study their effectiveness in improving asset utilization as well as T&D upgrade deferral. It was found that a single substation storage device is beneficial to provide incremental capacity to defer a minimal investment in substation equipment. For a significant T&D upgrade deferral, multiple substation storage devices in a single or multiple substations would be required. Further, CES devices do not provide any benefit to reduce future circuit infrastructure. On the other hand, localized energy storage technology (in which storage units are placed downstream from substations) provides the most benefit in avoided future infrastructure. However, in coordination with PacifiCorp's current subdivision design standards which are designed for the most effective and efficient operation of the distribution system, the commercially available localized energy storage devices would be heavily underutilized due to their limited kW size. Also, increased losses from additional distribution transformers, increases in capital infrastructure cost per subdivision, as well as cold load pickup are issues that would need further detailed evaluation.

PacifiCorp, in collaboration with EMB Energy Inc., worked towards testing and integration of a flywheel energy storage technology for electric power systems. The proprietary flywheel design developed by the EMB team in collaboration with Lawrence Livermore National Laboratory was expected to drive down the unit price of flywheel-based electrical storage. However, EMB Energy was unable to maintain financial stability and eventually lost its investors. Due to these

[14] IEA-ETSAP and IRENA Technology Policy Brief E18 – April 2012

reasons and prolonged delays in providing the expected results, PacifiCorp has decided to terminate its involvement in the project.

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 practicable 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 with 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 restore service 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 IEDs in distribution line equipment (specifically reclosers, sectionalizers and faulted circuit indicators) provides the outage management system with intelligence that can be used to isolate the faulted sections of the system in reduced timeframes.

Fault Detection, Isolation and Restoration (FDIR)

An FDIR program utilizes strategically placed distribution reclosers, motor operated switches and fault detection devices to automate restoration. These systems enable the utility to remotely or automatically reconfigure the distribution network in response to an unplanned or planned outage. 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 reducing the outage time.

FDIR has been tested and used in niche applications within the electric industry for over ten years. In the context of the smart grid, the distribution system will need to adapt to optimally serve and restore customers by using non-traditional feeder routes. Since sectionalizers do not have automated restoration abilities they will need to be replaced by reclosers. FDIR has traditionally been referred to as distribution automation and PacifiCorp has implemented a couple of projects using this technology. Modernizing PacifiCorp's distribution grid with FDIR technology would require a significant investment, the benefits of which cannot be guaranteed at this point in time. The evolution of architecture options and technology choices in the area of FDIR has not yet matured and it is in the best interest of the company and its customers to monitor the developments in this technological space.

## 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)." [15]

PacifiCorp uses the term RAS 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 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 use 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 offline to be protected from damage. Without the RAS a cascading outage might be hard to avoid.

[15] http://www.nerc.com/files/Glossary_2009April20.pdf , p 18

Transmission smart grid is generally synonymous with the phase measurement unit (PMU, or synchrophasor) and the communication network which links many PMUs to a central processor. The PMU is the building block of 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[16]. The PMU can also be used to increase reliability by synchrophasor-assisted protection due to line condition data being 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. PMU implementation and further development may enable transmission operators to integrate variable resources and energy storage more effectively into 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. PMU deployment is dependent on a WAN of sufficient geographical coverage, bandwidth, reliability, security and latency to enable PMU functions. Specific data processing and decision logic are required for operations.

A WAN 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. The deferral or elimination of new or upgraded transmission lines is not facilitated by the synchrophasor program as envisioned in this report. Research is currently being conducted into whether dynamic ratings can help 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 line.

[16] http://www.eia.gov/todayinenergy/detail.cfm?id=5630

## Technology Dependency

Many of the technologies required to migrate the existing electrical system to a full 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 from any program analysis. For instance, to gain the full benefit of IVVO the distribution management system must be developed and integrated into the information and communications systems prior to field deployment of the smart-grid enabled capacitors and line regulators.

Figure 5 illustrates the technology dependencies for the PacifiCorp smart grid. The illustration shows that a functional smart grid must be built from the top down and along the paths indicated. The only exception to this requirement is the transmission synchrophasor system, which is being built out independently of the other systems.

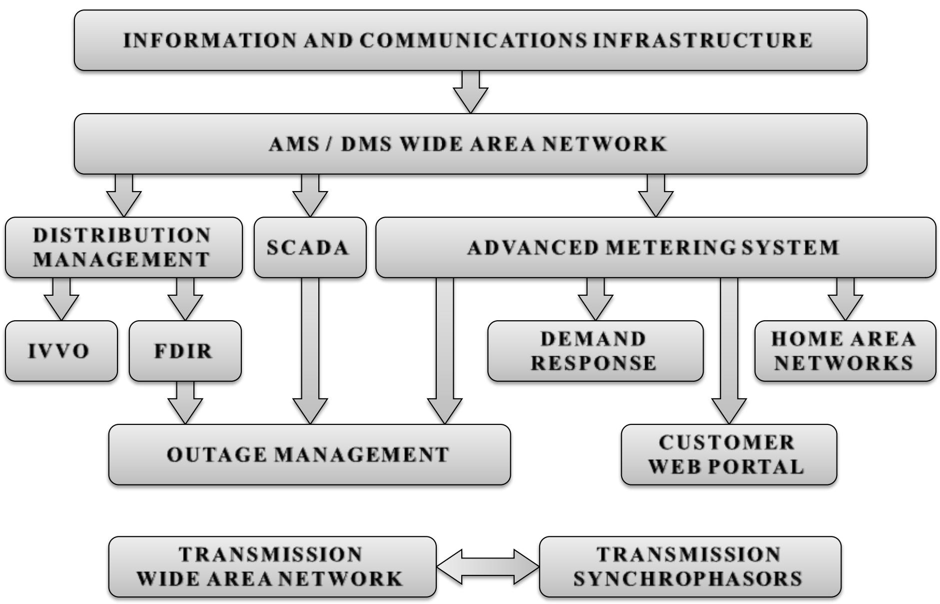


**Figure 5 – Smart Grid Technology Dependencies**

## Smart Grid Projects

PacifiCorp has implemented a number of smart-grid related projects, both past and present, with more currently in the research and planning phases. This section describes projects in the transmission, substation and distribution environments, as well as demand-side management investments.

### Transmission Network and Operations Enhancements

Transmission Synchrophasor Demonstration Project

PacifiCorp is participating in the Western Electricity Coordinating Council (WECC) Western Interconnection Synchrophasor Project (WISP)[17] which includes matching funding under the Smart Grid Investment Grant (SGIG) of 50 percent. WISP is a collaborative effort between partners throughout the U.S. portion of the Western Interconnection.

PacifiCorp has committed of funding 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 phasor measurement units (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 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.

PacifiCorp currently has three substations, Jim Bridger (Wyoming), Wyodak (Wyoming) and Camp Williams (Utah), that have PMUs installed and streaming data to WECC via two phasor data concentrators (PDCs) installed in a company facility in Salt Lake City. The PDCs collect and archive real time data streams from remote substation site PMUs and transmit the real time data to WECC in Vancouver, Washington. Two additional substations, Populus (Utah) and Mona (Utah), have PMUs installed and are expected to have data streaming to WECC by the end of July, 2013.

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[17] http://www.wecc.biz/awareness/pages/wisp.aspx

The installations of the first five PMUs and the two PDCs have come in under budget, leaving room for PacifiCorp to add additional PMUs to the bulk electric system. Three additional substation sites have been chosen, Monument, Emery and Dave Johnston Plant, and the necessary equipment is being ordered to facilitate the installation of these additional PMUs. The current schedule calls for these three sites to be completed and the PMUs streaming data to WECC by the end of 2013. The installation of these additional PMU sites will satisfy PacifiCorp's commitment to the synchrophasor project.

WECC has released the initial test version of their WAN, which includes a Wide Area View (WAV) tool. The WAV tool allows users to see all of the participating PMU sites in the Western Interconnection and all of the real time data that they provide. This version was released to allow participating entities the opportunity to navigate the program and submit their feedback to help improve the actual WAV tool[18].

Participating utilities are scheduled to complete the installation of all respective PMUs and have them streaming data to WECC by the end of September, 2013. Overall, WECC anticipates closing this initial phase of the project by the end of April, 2014. WECC expects the installation of PMUs to continue in the Western Interconnection even after the satisfying of the WISP incentive program.

### Dynamic Line Rating Projects

Company standards currently use static winter and summer ampacity limits to rate lines. Installing DLR systems in certain locations will allow the Company to monitor lines for potential loading to maximize power flow based on real-time conditions instead of the static seasonal ratings. One necessary precaution that must be taken when determining the applicability of DLR on a line is determining whether the line itself is the limiting factor in the transmission path. If equipment on the path turns out to be the limiting factor, DLR will not be the appropriate technology to implement, as it will create the danger of increasing the power beyond the weaker element's handling capabilities. Company planners and engineers must keep this in mind when determining locations for potential DLR application.

PacifiCorp has identified two locations within its transmission system where real-time dynamic thermal line rating (DLR) systems will be beneficial: the first DLR equipment installation was implemented on the 31 mile long 230 kV Miners-Platte line located in the southern part of Wyoming; the second project will install DLR systems on three of the 345 kV lines from Populus substation to Borah and Kinport substations located in the southern part of Idaho, having a combined length of 147 miles.

[18] https://www.weccrc.org/realtime/Pages/WAV.aspx

Real-time monitoring systems will be used to increase the maximum power flows through these circuits while avoiding clearance infringements and physical damage to the conductor systems on the lines. The key benefit of DLR technology is to optimize the transfer capability of the existing transmission system with minimal capital investment. In both applications the line conductors are aluminum conductor steel-reinforced (ACSR), electrical clearances at maximum temperature are a concern, and the sections to be dynamically rated are over 30 miles long.

PacifiCorp selected the CAT-1 line monitoring system offered by The Valley Group for both projects. The CAT-1 system calculates dynamic operational line ratings (amperes or MVA) using line section tension readings from load cells installed on the lines. Measurement data is taken from multiple sensing locations throughout the lines and the data is communicated via radio to a central master station located at a substation. The master station processes the information and communicates it to the Company dispatch center. The dispatcher has a screen display that shows the real-time maximum rating of the line, enabling the dispatcher to make load-related dispatch decisions that utilize the maximum real-time load capability of the line.

The 230 kV Miners-Platte line received phase 3 rating approval from WECC in early 2013, which indicates that the study is concluded and the project may be placed in service. The multiple-line 345 kV project on the transmission lines west of the Populus substation is currently under construction and is scheduled to be completed and operational in Spring 2014. As this is a more complicated installation, the test phase of this project will be longer than the Miners-Platte DLR project test phase.

### Substation and Distribution Network Enhancements

Conservation Voltage Reduction Pilot Project

PacifiCorp's recent CVR analysis began as a response to a Washington voter-approved initiative, codified as RCW 19.285[19] in Washington State. This initiative calls for regulated utilities to pursue cost effective, reliable and feasible distribution efficiency savings. PacifiCorp worked with the Washington Utilities and Transportation Commission's Demand Side Management Advisory Group to define the CVR pilot's scope and cost recovery mechanism in order to ensure compliance with the state's requirements.

In 2011 a group of nineteen distribution circuits in Washington State were studied for potential energy savings. Four of these circuits were selected for a 2012 CVR pilot project. Of the 0.09 aMW predicted to be acquired through the four pilot circuits, less than 0.01 aMW was actually achieved. Both before and after voltage reduction, all four circuits failed to meet the protocol

[19] http://apps.leg.wa.gov/rcw/default.aspx?cite=19.285

efficiency thresholds required for rigorous measurement and verification. Thus, the energy savings could not be verified by the approved method, since the Simplified Protocol[20] scope requires that the thresholds be met. The estimated savings from the metered data, ignoring the threshold violations, is 0.017 aMW at the Clinton substation and zero or negative energy savings at the Mill Creek substation.

Due to the level of estimated savings the Clinton pilot was not found to be cost effective. Less than half of the anticipated reduction in average voltage was achieved and the estimated cost of energy savings was $112.49/MWh, which is 23% higher than the avoided purchase energy rate used in Washington. Due to protocol threshold violations, confidence in both the voltage reduction value and energy savings value are consequently very low. For the purposes of reporting savings toward the Company's 2012-13 conservation targets in Washington, zero energy savings will be claimed for both Clinton and Mill Creek due to the inapplicability of the protocol scope. Future system reconfiguration needs identified around Clinton substation further highlight the danger of long-term energy savings predictions.

With regard to the reliability of energy savings from voltage reduction, the pilot project showed that actual energy savings appear to be less than one tenth of that predicted by rigorous and detailed system analysis. A second study, named the Tier 2 study, highlighted limitations in circuit analysis as a project risk and led to the conclusion that energy savings from voltage reduction cannot currently be reliably acquired at PacifiCorp.

With regard to the feasibility of energy savings from voltage reduction, the pilot project helped the Company appreciate the difficulty in accurately predicting feeder voltages at varying load levels. State estimation and Advanced Metering Infrastructure research conducted by the Electric Power Research Institute and the Institute of Electrical and Electronic Engineers Energy in 2012 highlighted the critical nature of this industry hurdle. The Tier 2 report also acknowledged that load variations create challenges when measuring small voltage and energy changes.

Existing Company practices were a principal component of the 2010-2013 analysis. These practices include utilizing line drop compensation and minimizing the total cost to company and customer through prudent system improvements. These practices tend to have a negative effect on CVR benefits, since the Company has already gained much of the financial benefits of typical CVR projects. This, coupled with the fact that detailed studies of circuits do not yield reliable predictions of energy savings potential, as well as problems with the measurement of small energy savings causing costly complications leads to the conclusion that energy savings from CVR cannot currently be achieved in a cost-effective manner. A periodic review of the state of

[20] http://rtf.nwcouncil.org/measures/measure.asp?id=180

the technology, measurement protocols and the economics of such projects will be included in future editions of this document.

Communicating Faulted Circuit Indicators

Non-communicating faulted circuit indicators (FCIs) have been used for years to visually indicate fault locations on PacifiCorp's distribution lines. Recent advances in technology have enabled communicating faulted circuit indicators (CFCIs), that can send alerts to operations centers and mobile troubleshooters, as well as enabling the ability to log data for engineering planning and analysis. Due to recent expansion, PacifiCorp has begun researching CFCI applications in Utah. Analysis of the costs, benefits and best practices will then be applied to all of the company's distribution systems.

CFCIs have the potential to improve reliability indices such as customer average interruption duration index (CAIDI) by reducing the amount of time between the initiation of a fault and its detection and location. The fault location function of a CFCI operates by sending a signal to an outage management system or a troubleshooter, indicating that a fault has occurred and giving its approximate location. This data can be sent as a simple GPS coordinate or other locational data point or it can be incorporated into a more advanced algorithmic system which may be able to pinpoint the potential fault locations more precisely.

Many CFCIs also have the ability to transfer line loading data, temperature and other line parameters, which enables planning and algorithmic waveform analysis which can be used by planners and engineers to optimize circuit design and detect incipient faults.

Engineers at PacifiCorp are currently researching circuits on which CFCIs may prove most beneficial and are analyzing the potential impact of these sensors on reliability indices and planning processes. A preliminary cost/ benefit analysis was conducted to determine the value of applying CFCIs to a number of circuits with higher CAIDIs. In the Rocky Mountain territory less than 60 circuits exhibited a positive benefit/cost ratio with seven showing benefit/cost ratios above two.

In light of this analysis, PacifiCorp engineering is in the process of implementing a pilot project in the Rocky Mountain Power area to fully ascertain the benefits and costs of these communicating sensors and to gain experience with the operational elements involved in their application. An update on this project will be included in subsequent smart grid reports.

## Demand-Side Management

Pay-For-Performance Irrigation Program

PacifiCorp has offered an irrigation load control program in various configurations for several years. These programs have been designed to reduce peak load by allowing PacifiCorp to control participants' irrigation loads during periods of peak demand.

In 2010, the Company initiated a review of its Irrigation Load Control Program in an effort to understand the impact of the program on its system. Given the challenges regarding the geographic location of Utah irrigators, lack of interval data and the inability of the Company to obtain aggregated data from system meters, the analysis was limited to Idaho irrigators. A third party review of the 2009 and 2010 control seasons indicated that realized reductions ranged from 17% to 86% of expectations depending on the month and hour the load curtailment event occurred.

During the 2012 Program Season, the Company called 12 control events. Given the number and dispersion of events and the ability to analyze the Idaho program at an aggregated level (due to the concentrated nature of participants and the availability of system data), the Company was able to gain a further understanding of the system's performance over the entire control season.

The average realized load reduction for the 2012 Program Season was 139 megawatts, or 57% of the participating load. During the ten-year system peak period (ten year actual system peak days) the 2012 average realized load reduction was 117 megawatts or 48% of the 244 megawatts of participating load. Incentive payments or credits to participants for 2012 were based on all 244 megawatts of participating load. Participating load is the sum of the non-diversified peak demand associated with the participating sites, including the demand placed on the company's system during off-peak hours associated with loads associated with golf courses, cemeteries, etc. This data is illustrative of the performance of the Company's current irrigation load control programs in Idaho. While similar data regarding the performance of the Utah Irrigation Load Control Program is not available, it is reasonable to assume that results in Utah have been similar to the program performance in Idaho.

The Company has been able to reduce operating costs for 2012 by renegotiating the scope of its contract with its service provider and utilizing inventoried equipment as it prepared for a new request for proposal (RFP) for control equipment and services. During 2012 the Company issued a request for proposal in an effort to identify alternatives to deliver the program in the most cost efficient manner. The RFP asked respondents for two options:

> Option 1: The contractor would deliver the dispatchable irrigation load control program under a fully outsourced pay-for-performance model, accepting all the costs and risks to create, maintain, and manage the program. This option required respondents to provide

capacity, provide both monitoring and load control devices, and pay incentives to customers.

Option 2: The Company would continue operating the dispatchable irrigation load control program, with an internal program manager utilizing contractors for the field operations, program database, dispatch software, and customer interface activities. To support a Company operated program contractors were asked to provide proposals for equipment installation, operation, maintenance, and customer service associated with the program under the terms specified in the RFP.

While the focus of the RFP was on the existing programs in Utah and Idaho, proposals were also obtained for California, Oregon and Washington.[21] Targeted load reductions were established for each state.

The Company received five proposals from two qualified vendors; two pay-for-performance proposals and three equipment and service proposals. The proposals were evaluated to determine the least cost option after consideration of risk. To facilitate this evaluation, the incentive level and structure currently approved by the Idaho and Utah Commissions were utilized.

The results of the pricing analysis of the five proposals on a cost per kilowatt of realized reduction gave the least cost option as the pay-for-performance proposal submitted by EnerNoc, Inc. In addition to being the least cost option, EnerNoc assumes all equipment and delivery risks associated with the program.

EnerNoc currently manages over twenty-five pay-for-performance contracts in the United States. The equipment being proposed by EnerNoc is a two-way communication solution designed specifically for irrigation load control applications by capturing and communicating near real-time irrigation load data on five-minute intervals, and enabling direct control of irrigation pumps and equipment.

EnerNoc's pay-for-performance proposal was selected, based on the pricing, risk and technical evaluations performed during the RFP process. Negotiations regarding the final agreement began shortly after the vendor selection.

Based on the 2011 Integrated Resource Plan, the Irrigation Load Control Program is cost-effective based on the utility cost test. The 2013 Integrated Resource Plan includes as an existing resource the 40 MW of Average Demand Response Capacity associated with the EnerNoc

[21] Pricing information for irrigation load control in California, Oregon and Washington were provided for inclusion in the Integrated Resource Planning model.

agreement. Pricing information for incremental irrigation load control in Utah was provided for inclusion in the Integrated Resource Planning model and, if selected, the contract will be modified to include the additional capacity requirement.

## Challenges and Risks

While there are many benefits to the smart grid, there are also many challenges involved in its deployment and its impact on future operations of the electric system. Some of these challenges relate to integration of communication standards and device interoperability, ensuring proper security for devices, systems and customers, refining and determining appropriate levels of communication with customers, and the impact that disruptive technologies may have on the electric distribution system and workforce.

The electric system in place today is a result of an expansion that was predicated upon economics, and as such, was engineered to minimize costs, with redundancy and reliability having been seen as lower priorities. As growth occurred, that fundamental design precept has not significantly altered. Some industry analysts maintain that customer engagement is more important than costs. Thus, the fundamental economics are no longer the most critical aspect of the system; rather, the ability of the customer to engage with the electric delivery system is of higher priority. This shift in focus will result in significant costs for current and all future system investment. Equipment, communications protocols and even staff will be more technologically advanced, and will require more routine "refreshing" to maintain compatibility with future advancements.

### Interoperability Standards

The current lack of interoperability standards risks premature obsolescence of equipment and software installed prior to their widespread adoption. As electric utilities continue to expand existing infrastructure and implement new smart grid related systems, long-term investments should support a corporate 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 EISA of 2007 specified that the Department of Energy champion this effort. The DOE authorized NIST to develop uniform protocols that facilitate information exchange between smart grid devices and systems[22]. 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 interoperability between AMI vendors and has issued its "roadmap" for developing the necessary standards. NIST has cautioned that "as they mature, these standards are undergoing revisions to add new functionalities to them,

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

integrate them with legacy standards, harmonize them with overlapping standards, and remedy shortcomings that are revealed as their implementations undergo interoperability testing." To this end, the NIST framework endeavors to utilize the reporting and experiences of ARRA grantees to work with standards development organizations and standards setting organizations to improve foundational smart grid standards.

The smart grid initiatives that have evolved over the past few years have given rise to a wide array of new markets and opportunities based on innovative technologies. This stresses how important interoperability standards are to a functional, reliable smart grid.

Stakeholders who are not monitoring NIST's activities risk having current investments become prematurely obsolete and will be more challenged in realizing all the benefits that are expected from existing equipment. In addition, many of the smart grid standards under review are immature or non-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 are proven to deliver expectations.

## Security

The smart grid increases the amount of intelligent data to a level never before seen in the power 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 of the smart grid at this time. The North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP)[23] reliability standards were designed to protect the bulk power system against potential cyber security attacks, but these standards do not yet 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. This increase in operational cost is not reflected in this study.

PacifiCorp is currently participating in grid security studies hosted by NEETRAC and financially supported by DARPA. The studies are attempting to prove or disprove the feasibility of a

[23] http://www.nerc.com/page.php?cid=6|69

fingerprinting technique which will detect anomalous activity on transmission and substation SCADA systems. If the testbed is proven out it will enable utilities to automatically quarantine malicious devices as soon as they are detected. The project is focusing on open source coding and off-the-shelf systems in order to keep the solution flexible and low-cost.

### Customer Communications

The smart grid presents a new and fundamentally different channel of communication between PacifiCorp and its customers. Transmission of usage data can be conducted in real time, not just on a monthly basis as is currently the case. Broadcasting 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 visits a website using Greenbutton data[24] to inquire about their charges-to-date. Enabling customers to optimize their experience with evolving technology and helping them understand the benefits of advanced metering is a crucial element of a smart grid 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 challenging prospect with potential for unforeseen challenges that could result in significant cost overruns.

Another challenge that PacifiCorp will face is customer recruitment. DR programs should preferably be opt-out programs. To retain customer participation, PacifiCorp 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 or a third-party marketing firm or, if done in-house, new software functionality to handle DR recruitment, enrollment, and customer management as well as DR 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 DR equipment installation company, and various DR communication systems.

PacifiCorp will also need to re-examine how customer service is provided during deployment and after the AMS is completed. The call center will need to be able to effectively work with customers to take advantage of more detailed information on energy use and spending and how

[24] http://www.greenbuttondata.org/greenabout.html

to apply it to customer concerns. This includes providing the customer education needed to increase understanding of the benefits of smart metering and reduce fear and distrust of the system changes.

Call center 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 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.

## Meter Data Management

The smart grid also 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, PacifiCorp becomes a 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, DR events, verification and reporting of energy saved, etc.) the enormity of the challenge becomes clear.

To illustrate, every day the AMS operations team must support:

- More than 45,000,000 meter reads per day (assuming one-hour interval data)
- More than 4,000 meter exchanges per day during deployment
- More than 500 customer moves per day (based on 10 percent yearly turnover)
- 10,000 missing reads per day (99.5 percent daily read success)
- 10 meter failures per day (0.25 percent annual failure rate)
- 10,000 data changes per day

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

## Distributed Generation

Distributed generation (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 negatively 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 generation systems increase, the need for a smart grid will become more apparent.

Distributed generation requires the measurement of electrical energy in both directions. Energy delivered by the electric utility and energy received by the grid must be measured to provide the appropriate billing charges and credits for energy consumed and 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. This increase in meter cost is not reflected in the economic analysis of PacifiCorp's smart grid program.

PacifiCorp has performed studies to evaluate potential sites for solar installation and continues to work with customers, city officials and other stakeholders interested in connecting distributed generation systems to the Company's electric grid. Further, the Company has taken a proactive approach to address customer concerns and has recently released an interconnection guide for customers looking to connect generator systems rated at 2 MW or less. It is the Company's hope that this will help customers gain a better understanding of the various interconnection requirements necessary in order for PacifiCorp to operate the grid reliably and safely.

### Smart Grid Solar Energy Study

PacifiCorp performed a detailed study on a distribution circuit in Salt Lake City to determine the viability of distributed solar generation in an urban setting. The evaluation included identifying the percentage of rooftops within the study area that were viable for solar panel installations, total project cost to install the solar panels and the required metering infrastructure.

The study showed that of the 356 structures within the service area, 237 (67 percent) had rooftops capable of receiving a minimum level of solar insolation per day. Under the scenarios evaluated it was concluded that institutional buildings are estimated to have the greatest potential for installation of PV panels, followed respectively by commercial buildings, unknown land use buildings and single family residential buildings. Further, as shown in Figure 6, the study showed that the time of the maximum solar output does not coincide with the daily distribution system peak of the "Northeast 16" circuit. This illustrates that rooftop PV systems are an ineffective solution for offsetting investments towards distribution infrastructure.

The detailed data, analysis method and results are provided in the "Smart Grid Solar Energy Study" report. A copy of the report can be obtained by contacting PacifiCorp.

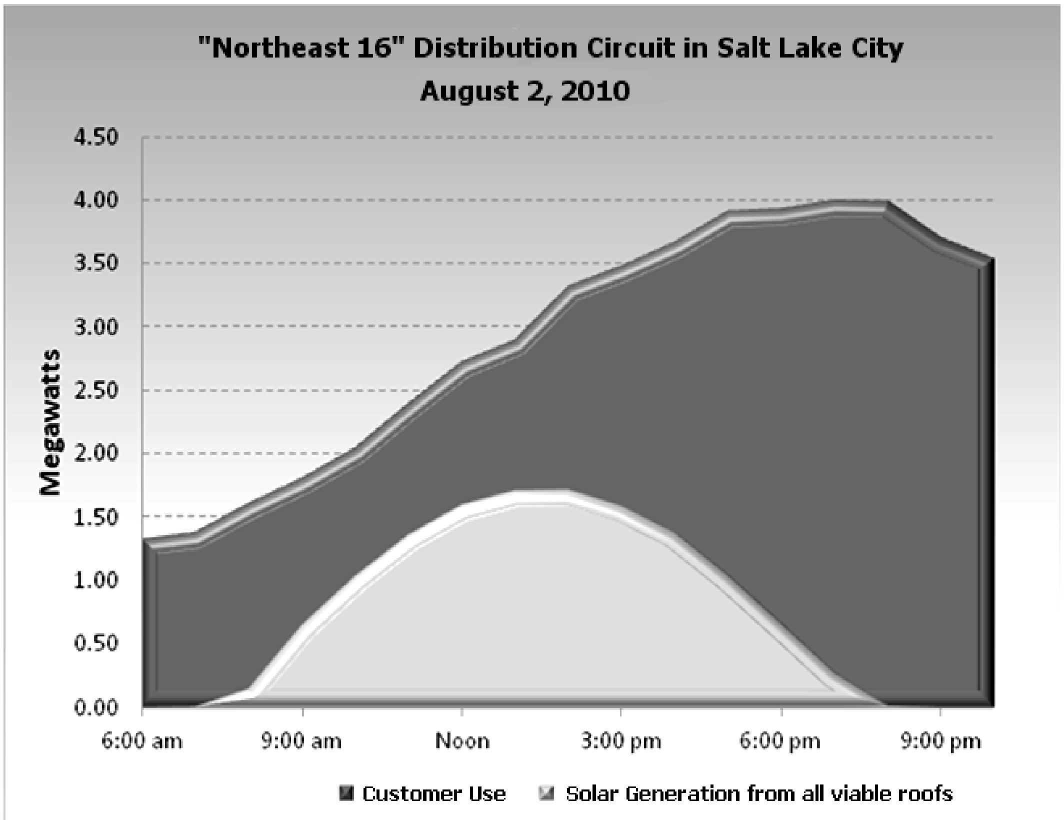


**Figure 6 – Daily Peaks for Solar Energy Study**

Plug-In Electric Vehicles

Plug-in electric vehicles (EVs) are expected to become more widespread as EV and battery technologies advance and EV purchase prices become more competitive with gasoline vehicles. It is commonly accepted that widespread adoption of plug-in electric vehicles will have a large impact on the electrical distribution system in general and distribution transformers specifically. Future battery technologies and plug-in electric vehicle enhancements may lead to utilizing plug-in electric vehicles for vehicle-to-grid (V2G) and vehicle-to-building (V2B) energy supply for demand response and outage ride-through. At this time PacifiCorp expects plug-in electric vehicles to only be a new load to the system.

To ensure that these vehicles do not adversely impact the distribution system or customers' home premise wiring, development of interoperability standards will be required along with necessary changes to electric price tariffs, electric service schedules and building codes. As large scale introduction of electric vehicles occurs, the definition of on-peak and off-peak energy usage may change as well.

Electric Vehicle Penetration and Vehicle-to-Grid Technology

PacifiCorp began researching the effects of widespread electric vehicle penetration in 2010 by tracking EV sales, technologies and economic trends. While initially interested in the deleterious effects of increased loading on distribution transformers, the Company also took the opportunity to begin studying potential smart grid applications of electric vehicles. The ongoing results of this research have been helpful in understanding the potential growth of electric vehicles and the resulting impact on PacifiCorp's distribution network.

PacifiCorp currently expects the load growth due to the adoption of electric vehicles to be small and manageable, with large-scale deployment of EVs having limited negative impact on the Company's electric grid. The company continues to work with Clean Cities Coalitions and other entities within our service territory to facilitate public charging infrastructure development, discussions and opportunities. The EV section of the company's website has recently been updated with the latest information on the technology and infrastructure requirements to install residential, commercial and public charging stations.

The Energy Information Administration (EIA) has been consistently ramping down their electric vehicle sales growth forecasts to reflect slow economic growth. For instance, in 2007 the EIA forecast[25] sales of hybrid vehicles to be about 1.5 million units sold in 2020; in 2012, that figure was revised to 450,000[26], a downgrade of nearly 70%. This downgrade is consistent for forecasts out to 2030. This indicates a cooling of the electric vehicle market, although this may change if the economy picks up, petroleum prices continue to rise or battery technologies continue to improve.

V2G promises quick-response, high-value electric services to balance constant fluctuations in load. However, though V2G research provides the engineering rationale and economic motivation for widespread implementation, commercial availability of electric vehicle supply equipment and batteries robust enough to implement this technology remains scarce.

The Electrification Coalition points out some of the main issues with V2G technology[27]:

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[25] ftp://tonto.eia.doe.gov/forecasting/0383(2007).pdf, Figure 52, p. 81
[26] http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf, Figure 91, p. 85
[27]Electrification Coalition. (2009). *Electrification Roadmap.* Retrieved August 15, 2012 from http://www.electrificationcoalition.org/policy/electrification-roadmap, Section 2.4.5 "Vehicle to Home and Grid"

- Applications are unlikely to appear before third or fourth generation electric vehicles evolve
- V2G technology requires bidirectional chargers, which are more expensive than traditional chargers
- Software development is required by both utilities and equipment manufacturers in order to enable communication between the grid and the in-home chargers
- Researchers need to gain a better understanding of the deleterious effects on battery life when charge/discharge cycle frequency is increased

Companies such as LG Chem, EnerDel and Valence Technology that make EV and grid-tied batteries are finding it hard to stay solvent due to lower than expected demand for electric vehicles, volatility in the economy and a scarcity of investors.  Without reliable battery manufacturers, electric car makers, utilities and other companies may find it hard to make long-term decisions concerning centralized and decentralized storage, vehicle batteries and battery-based smart grid applications.

## Economic Review

Each of the components identified for PacifiCorp's smart grid study have quantifiable costs and benefits that were used to determine the rough potential of investing in those technologies. Although no proven costs or savings calculations exist for all of the components, estimates can be used to gauge these costs and benefits. There is also enough established theoretical data on savings opportunities from 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 future generation capacity and energy markets, percentage of the customer base participating in dynamic pricing programs and the energy conservation achieved by those customers.

All of the cost and savings data presented contains the most reliable data available at the time of publication. A conservative approach was used in all aspects to protect the integrity of the estimates. The cost and savings assumptions will be updated as actual and time proven data becomes available to help maintain a current assessment of the potential for investment options.

### Benefits and Savings

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

Consumer-based savings are directly attributed to changes in consumer energy-use behavior and are unproven benefits with uncertain sustainability[28]. These savings 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 and mandatory time-of-use coupled with critical peak pricing structures consumers are unlikely to have the incentive to make the behavioral changes required to realize the benefits of a smart grid. Models for time-of-use pricing structures are complex and will require significant levels of study and debate to arrive at the proper design. Due to these factors pricing models remain outside the scope of this study.

Measurement of consumer-based savings can only be estimated as a reduction in generation requirements and as measured by the associated marginal pricing. Additionally, Company-based savings could be estimated as a reduction in capital requirements for electrical infrastructure

[28] http://opower.com/uploads/library/file/3/residential_energy_use_behavior_change_pilot.pdf

expansion and replacement. However, these savings are only temporary in nature as customer load growth will continue to drive 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 gases 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. For this reason, and the purposes of this report, these benefits will not be included in the analysis.

Advanced Metering System

The major risks for deploying advanced metering systems include vendor selection, home area network protocol, interoperability of components and customer acceptance. As previously mentioned, regulatory approval of new and revised time-varying rate structures and customer participation in these rates is a key component for success.

Some utilities are experiencing customer backlash over perceived privacy and RF issues surrounding smart meters. Halt MA Smart Meters is a Massachusetts-based organization whose stated goal is to fight smart meter installations and is currently pushing for a no mandate/no penalty fee opt out. Other consumer groups around the country are taking similar stances. Utilities will need to deal with pushback from groups like these and increase customer awareness of the benefits of smart grid technologies as well as addressing serious concerns. Non-profits such as the Smart Grid Consumer Collaborative (SGCC)[29] are working on websites and informational pamphlets that counter many of the anti-smart meter claims.

As with any new technology, employee training and business process changes must occur to gain the expected benefit of an AMS. Technology specific training has been identified and included in the individual technology cost calculations. Costs for business process changes have not been fully determined, but a reasonable estimate is included for a more accurate cost estimate of a smart grid. The benefits of the AMS result 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.

The costs associated with the accelerated depreciation of the current metering asset will need to be continually calculated and modified as the system is installed. Several areas within PacifiCorp's service territory have recently been converted to AMR systems and others may be converted where practical. The accelerated cost of depreciation for those systems will be higher

[29] http://smartgridcc.org/

than in areas with older metering systems. The cost of accelerated depreciation has not been included in this analysis. That cost will be calculated in a detailed analysis, after the risks of the assumptions are lower. Such an analysis will be completed prior to any regulatory filing for advanced metering or smart grid.

### Demand Response

The AMS presented in this business review 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 afternoon/early evening.

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. These events would be available to be called, if needed, up to 20 times per summer depending on the utility tariff design. 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.

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 programs and rates would require regulatory support in Company jurisdictions. The benefit assumptions for DR in this review assume mandatory TOU and CPP for residential and small commercial customers. Absent regulatory support for mandatory programs, the assumed benefits 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 are described below.

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 of the tariffs 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 cost 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 DR pilot programs, while informative, remains insufficient to accurately predict results on a larger scale, across multiple jurisdictions, and in a low retail rate environment.

Scenario 1- Mandatory TOU/CPP

This type of rate structure is expected to encourage energy usage away from the daily peak load periods. Additional demand reduction could be achieved under this scenario with occasional CPP events triggering higher prices, which are more reflective of the costs associated with meeting critical peak demand. The CPP tariff would apply to all residential and commercial customers. All customers would be given a basic CPP event indicator device that has three color-coded indications of relative kWh pricing, representing off-peak (cheapest pricing), on-peak pricing, and critical peak pricing. Signaling to the device would be through the smart grid’s communication system into the home. Only one-way communication to the device would be necessary. Customers could choose to sign up for day-ahead notification through email, texting and social media channels.

Customers could also choose to purchase a more robust notification system like an in-home display (IHD) that gives the customer actual kWh pricing, in addition to notification of CPP events. Another option for customers is the purchase of devices to help automate their response to CPP events, such as a programmable communicating thermostat or a home automation system. These types of devices would automatically respond to CPP event notifications and reduce customer energy use to a pre-set level determined by each customer, providing the greatest opportunity for DR and energy use reductions. To help improve customer response to CPP events, PacifiCorp would offer a coupon for upgrading to an IHD, a communicating thermostat, or a home automation system. Most of the costs for this CPP program would be in the initial rollout of the tariff, purchase and distribution of basic CPP indicators, notification and control systems, equipment coupons and customer education. The majority of these costs would be spent in the first two years of the tariff implementation. Ongoing costs would consist of consumer education to maintain persistence of response during events, customer growth, assisting with the costs of replacement equipment due to customer movements and equipment failures, and the evaluation of the resulting load reduction.

Scenario 2 - CPP Opt-Out

This scenario is similar to Scenario 1. All customers would be put on the TOU and CPP rates as a default tariff. Customers would have the ability to opt-out of the CPP part of the tariff and only be on the TOU rate. This rate would have an off-peak period rate higher than the TOU rate with the CPP component to incentivize customers to stay on the CPP rate. With the exception of the marketing strategy, all of the other features in Scenario 1 would be the same in Scenario 2. It is expected that customer participation would stabilize during the first two years of the tariff implementation.

Scenario 3 – CPP Opt-In

For this scenario, all customers would also be on a TOU tariff to encourage energy usage away from the daily peak load periods. PacifiCorp would market the CPP tariff to customers. The incentive for customers to participate would be a CPP event indicator that also indicates the daily off-peak and on-peak hours, as well as the CPP events. In addition, the off-peak rate would be lower for this tariff than for the default TOU tariff. To help customers enhance their load reduction response, a communicating programmable thermostat or a basic IHD would be offered to participating customers, as well as a coupon to upgrade to a more sophisticated IHD or a home automation system. The utility would send a signal to the thermostat or home automation system initiating an automated response to the CPP event based on each customer’s desired response to events. For example, a customer with a programmable communicating thermostat could choose to have their temperature setting raised by five degrees in response to CPP events. It is expected that, with focused marketing and communication, it would take about 4 years to build the customer participation to the levels predicted in the financial analysis. In addition to the costs in Scenarios 1 and 2, this scenario would have higher marketing costs associated with customer acquisition and the cost of the thermostat or IHD provided as an incentive.

To maximize the benefits of DR in this review, the costs and benefits of Scenario 1(mandatory TOU with a CPP component) will be used. Scenario 1 provides the highest value in the business review with the lowest assumed implementation cost and highest assumed DR from customers. The voluntary nature of Scenarios 2 and 3 increases initial and ongoing marketing costs while in many cases also results 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 advanced metering and the associated communications were in place the deployment of DR on a broad scale would be beneficial.

Adjustments were made to the costs and benefits of DR for the residential and small commercial load management and pricing programs currently in place[30] and operated by PacifiCorp today. The costs of these programs were netted out of the cost and benefits of the broader DR applications envisioned in a smart-grid enabled environment. Whereas DR is responsible for over 70 percent 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 limited amount of data available on which to assess the requirements for a customer education program 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 initial filings reviewed, only Oncor Electric Delivery Company's 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

[30] The costs and benefits of Utah's Cool Keeper air conditioner load management program were netted out of the assumed costs and benefits of smart grid deployment. No adjustment was made for Idaho or Utah irrigation load management programs, or large commercial and industrial curtailment program as only residential and small commercial demand response was included in the development of this business review.

an advanced meter. To properly account for customer education programs throughout PacifiCorp's service territory, a conservative cost of $12 million has been included. This value was derived based on a lower customer count and a larger geographical service territory compared to Oncor.

Distribution Management Systems

PacifiCorp has a history of managing its distribution systems for optimal power factor, voltage profile, reduced line losses and increased system efficiency. This attention to managing the distribution system has required that numerous capacitor banks and voltage regulators be installed on the distribution system. The cost to migrate to a smart grid is mitigated by the fact that the existing line equipment will only require that the control panel be upgraded to enable two-way communications. In addition to the pre-existing line equipment, additional capacitor banks will be installed and controlled by the DMS in order to create a smoother voltage profile. 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. The ability of the capacitor banks to automatically report malfunctions will reduce maintenance costs as inspection programs can be reduced or eliminated.

The addition of faulted circuit indicators and automated field switching devices will create additional operational benefits due to 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 improved reliability indices, reduced outage calls to the call center, a reduction in the number of trouble tickets and a reduction in the number of truck rolls responding to non-outage conditions.

## Cost and Benefits Summary

The economics of the smart grid project were evaluated over twenty-five years to cover implementation and the twenty year expected life of the system. The economics include refresh rates for computer hardware, software and communications equipment and the remaining value of transmission and distribution assets installed under this program. The costs and benefits in 2013 dollars associated with each of the technologies defined for the PacifiCorp smart grid are detailed in confidential Attachment A. The costs and benefits are escalated based on the projected inflation rate, except for energy savings, which are valued based on projected power costs.

When reviewing the numbers it is important to remember the technology dependencies as laid out in Figure 5 of this report. For example, the savings associated with DR cannot be achieved without the investment in information technology, metering/distribution wide-area network and the AMS. The six case scenarios presented in the Roadmap section below include these interdependencies.

## Roadmap to the Smart Grid

To develop an objective roadmap for the implementation of smart grid technologies the economic value of the individual components must be considered and a determination of the maturity of the technology must be ascertained. Due to the co-dependency of some of the components only the AMS, DMS and TSP systems can be independently evaluated. Whereas TSP is a stand-alone function, this leaves the decision for the roadmap to begin with AMS or DMS. A stand-alone analysis of the key functionalities was performed to identify those with the highest value and to determine the order of implementation. The roadmap also portrays a timeline for implementation that considers both a consistent and level capital expenditure plan and a determination of resource requirements to obtain the number of years required for each component, including pilot installations and system stress testing prior to full-scale deployment.

To determine the proper order of implementation for the smart grid roadmap, the smart grid technologies were grouped into six case scenarios. Case 6 includes the total costs and benefits for the complete smart grid network as defined and follows the roadmap as shown in **Figure 7 – Smart Grid Roadmap**. The included components for each case are shown in Table 3 below. All cases include the required information technology, communications systems and required customer education costs that are necessary to implement the technologies incorporated into each case.

| Case | AMS | DR | DMS | FDIR | IVVO | CES | TSP |
|---|---|---|---|---|---|---|---|
| 1 | X | | | | | | |
| 2 | X | X | | | | | |
| 3 | | | X | X | | | |
| 4 | | | X | | X | | |
| 5 | | | X | X | X | X | |
| 6 | X | X | X | X | X | X | X |

**Table 3 – Case Components**

Each case analysis generated independent costs, annual benefits and the present-value revenue requirement (PVRR). Due to the high-level nature of this analysis, no sensitivity analysis was completed. All costs and benefits were considered to be "best case scenarios."

With the given analysis, a logical roadmap for implementation of a smart grid at PacifiCorp can be developed, starting with the AMS/DR projects. To properly plan the system, a detailed business case will be required, followed closely with working discussions with the state regulatory commissions and key stakeholders. Figure 7 portrays a potential timeline that provides for a systematic implementation. At the outset and during the duration of the program, ongoing review and analysis of the business case is necessary to ensure that financial integrity and compliance with emerging standards are maintained.

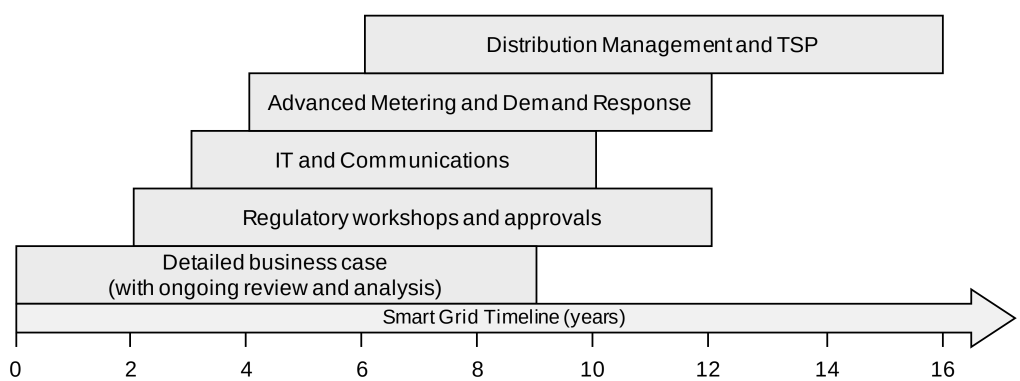


**Figure 7 – Smart Grid Roadmap**

## Conclusion

The present economics to implement a comprehensive smart grid system throughout the PacifiCorp territory are forbidding. Smart grid technologies do, however, show promise for future improvements in the operation and management of the transmission and distribution systems. 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 as well as distributed generation and increased renewable generation.

Most of the benefits associated with DR 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 costs and risks to PacifiCorp and its customers, it is essential that the market leaders be identified, system interoperability be verified, and to learn from other electric utilities to ensure that PacifiCorp makes prudent smart-grid investments.

PacifiCorp will continue to monitor 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. With large scale deployments progressing throughout the country, the market leaders will become evident within the next few years and will demonstrate whether sustained DR for large-scale roll-outs is supported by the precedent pilot programs.

# Appendix A - Common Abbreviations

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

| Abbreviation | Name |
|---|---|
| AMI | Advanced Metering Infrastructure |
| AMR | Automated Meter Reading |
| AMS | Advanced Metering System |
| aMW | Average Annual Megawatt (8760 MWh) |
| CAIDI | Customer Average Interruption Duration Index |
| CBM | Capacitor Bank Maintenance |
| CES | Centralized Energy Storage |
| CFCI | Communicating Faulted Circuit Indicator |
| CPP | Critical Peak Pricing |
| CVR | Conservation Voltage Reduction |
| DLR | Dynamic Line Rating |
| 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 |
| RFP | Request for Proposal |
| SCADA | Supervisory Control and Data Acquisition |
| T&D | Transmission and Distribution |
| TSP | Transmission Synchrophasors |
| TOD | Time-of-Day |
| TOU | Time-Of-Use |
| V2B | Vehicle-to-Building |
| V2G | Vehicle-to-Grid |
| WAN | Wide Area Network |

# Appendix B - Smart Grid Technologies at Other Companies

The PacifiCorp Smart Grid department researches smart grid projects around the country in order to assess technologies that may be of benefit to the Company and its customers. Listed here is a summary of the most relevant projects that the group has researched. All information here is publically available on company websites. No reviews of particular business cases have been completed on these projects.

- Portland General Electric (PGE), headquartered in Portland, Oregon, has installed more than 825,000 smart meters on customers in their system. This investment has further enabled other smart grid projects, including:
  - The Energy Tracker initiative, which gives customers access to their smart meter data and may help further PGE's demand side management programs
  - Time-of-use pricing for commercial and industrial customers
  - Direct load control programs which will enable PGE to reduce overall system load, currently by up to 17 MW.

  PGE has also incorporated dispatchable standby generation and distributed generation into their system. The Salem Smart Power Project began construction on May 21, 2012 and utilizes customer generation, a 5 MW, 1.25 MWh lithium ion battery energy storage system and automated line switching to increase system reliability. Benefit streams include increasing supply capacity, time shifting load, and firming up renewable capacity.

  PGE's Gales Creek project is improving uptime on a 13 kV line serving 800 rural customers. Using Cooper Power's Yukon Feeder automation system, the feeder, which has averaged 14 hours of outages per year, has experienced two successful operations since commencement of the project in December, 2011. This has resulted in 3 hours, 40 minutes of outage time avoided, markedly improving the SAIDI figures on the feeder.

- Avista, serving northern Idaho and eastern Washington (and operating with a rural, low-density customer base similar to PacifiCorp's), has invested in two smart grid projects. These projects are funded with matching grants from ARRA.

  In Pullman, WA, in collaboration with Batelle, Avista is installing smart meters on 13,000 electric customers' homes as a smart grid demonstration project. Avista hopes to implement distribution automation schemes in order to automatically detect outages and more quickly restore power by isolating faulted sections of circuits. Customers will also have access to a website which will help them track their energy usage and encourage energy efficient activities.

Avista's Spokane Smart Circuits project will impact 110,000 electric customers in the Spokane area. 59 distribution circuits and 14 substations are slated for upgrading to a new distribution management system with intelligent end devices. This project should help Avista decrease outage times, detect faulty equipment more quickly and regulate voltage on feeders more accurately, for an estimated savings of approximately 42,000 MWh/year.

As these projects are in part funded with ARRA grant money their progress will be tracked on the smartrid.gov website. The PacifiCorp smart grid team plans on continuing to watch as projects like these progress in order to learn more about best practices in the smart grid environment.

- Pacific Gas and Electric (PG&E) invested in an 8-10 million smart meter rollout and installation of 300 MW of compressed air storage, expending a projected $800 million to $1.25 billion in capital investments and $500 to $700 million in cumulative operating expenses over 20 years. PG&E hopes to see $600 million to $1.4 billion lower energy procurement costs; $200 to $400 million in avoided capital costs due to offsetting the need to build new power plants; $100 to $200 million in avoided operations and maintenance costs; a 10-20 percent improvement in grid reliability; and 1.4 to 2.1 million metric tons of avoided carbon emissions.

  The cost comes to $12-$20 per customer account, averaging $4-$7 per year per customer. Higher rates over the last few years may have been mostly coincidental with smart meter installations, but customers have nonetheless attributed some of the higher prices to the smart meter rollout. PG&E has had to increase its community outreach plan due to customer unhappiness with the smart meter program and rate increases.

  On a positive note, PG&E has seen successes with its SmartAC DR program, reducing demand by up to 575 MW in some cases. PG&E has plans to continue growing its automated DR programs and looking at ways to integrate DR and solar generation load balancing.

- Southern California Edison (SCE) has perhaps done more to advance the current state of smart grid technology and understanding than any other US utility. With smart meters deployed to more than 4 million customers and rigorous renewable portfolio standards set by the state commission, SCE has some big challenges as well as opportunities in the smart grid arena.

The Irvine Smart Grid Demonstration, located southeast of Los Angeles on and around the campus of UC Irvine, has multiple elements:

- Energy smart customer devices, which will look at integrating home scale energy storage and PV systems in a residential environment
- An advanced distribution system with looped circuits, integrated volt-var optimization, utility scale storage and distributed generation capabilities.
- A secure energy network linking data back to:
  - The SCE back office
  - Various field networks
  - Customer in home smart devices

The project is taking place on two 12 kV distribution circuits, numerous residential homes and an EV charging parking lot at the UC Irvine campus. SCE is hoping to demonstrate zero net energy home functionality, in which over the course of the year homes will generate as much energy as they consume; reduced greenhouse gas emissions; and evaluate their smart grid implementation capabilities.

SCE is also investing in a $55 million energy storage project in the Tehachapi Wind Resource Area in an attempt to further energy storage research and applications, in part due to the California Public Utility Commission’s recent requirement of SCE to come up with 50 MW of storage. Using an 8 MW, 32 MWh lithium-ion battery system SCE will be measuring performance under 13 separate uses:

- Voltage support and grid stabilization
- Decreased transmission losses
- Diminished congestion
- Increased system reliability
- Deferred transmission investment
- Optimization of size and cost of renewable transmission
- System capacity
- Renewable energy integration
- Wind output shifting
- Frequency regulation
- Spin/non-spin replacement reserves
- Ramp rate
- Energy price arbitrage

The system will be operating in an area with an ultimate potential of up to 4,500 MW of intermittent wind power. The PacifiCorp smart grid group will continue to follow the project and watch for significant advances in the energy storage field.