BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of PacifiCorp (U 901-E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769	**Application No. 15-07-____** **(Filed July 1, 2015)**

APPLICATION OF PACIFICORP (U 901-E)
SETTING FORTH ITS DISTRIBUTION RESOURCE PLAN
PURSUANT TO PUBLIC UTILITIES CODE SECTION 769

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Date: July 1, 2015

Attorney for PacifiCorp

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PacifiCorp, d/b/a Pacific Power (PacifiCorp or the Company) respectfully submits its Distribution Resource Plan. This Application is made in accordance with California Public Utilities Commission (Commission) *Assigned Commissioner Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning* (ACR) issued February 6, 2015, California Public Utilities Code (PUC) §769 and Commission Rules of Practice and Procedure Rule 2.

I. INTRODUCTION/OVERVIEW

PacifiCorp is a multi-jurisdictional utility providing electric retail service to customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp serves approximately 45,000 customers in portions of Del Norte, Modoc, Shasta, and Siskiyou counties in northern California. This is a large geographic area with low population centers, with an average of 3.9 customers per square mile.

On August 14, 2014, the California Public Utilities Commission (Commission) issued Rulemaking (R.) 14-08-013 to establish the policies and procedures for the investor-owned utilities (IOUs) to develop their Distribution Resource Plan (DRP) proposals required by PUC

§769. On February 6, 2015 the Commission issued *Assigned Commissioner Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning* which set forth the final guidance for the content and structure of the DRPs to be submitted by July 1, 2015. The ACR provided additional guidance applicable only to the Small and Multi-jurisdictional Utilities (SMJUs). The SMJUs were directed to file DRPs that address the five statutory requirements in PUC §769 as it relates to their distribution systems[1] but are not required to conform to the guidance for PUC §769 attached to the ACR.[2]

Provided as Appendix A to this Application is PacifiCorp's DRP that addresses the following five statutory requirements in PUC §769:

(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation.

(2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

(3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

(4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net

[1] *See* ACR at p.13-14.
[2] *See* ACE ruling paragraph 3 at p.14.

benefits to ratepayers.

(5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

PacifiCorp respectfully requests the Commission approve PacifiCorp DRP, as submitted as Appendix A to this Application.

II. STATUTORY AND PROCEDURAL REQUIREMENTS

A. APPLICANT AND CORRESPONDENCE (RULES 2.1(a) and (b))

PacifiCorp is a public utility organized and existing under the laws of the State of Oregon. PacifiCorp engages in the business of generating, transmitting, and distributing electric energy in portions of Northern California and in the states of Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232.

Communications regarding this application should be addressed to:

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Portland, Oregon 97232
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In addition, PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

B. STATUTORY AND PROCEDURAL AUTHORITY (RULE 2.1)

Rule 2.1 requires that all applications state clearly and concisely the authorization or relief sought, cite by appropriate reference the statutory provision or other authority under which Commission authorization or relief is sought, and be verified by the applicant. The relief being sought is summarized in Sections I through III and is further described in the appendices supporting this application. PacifiCorp's authority for this request includes, but is not limited to, Section 769 of the California Public Utilities Code, and prior decisions, orders and resolutions of the Commission. PacifiCorp's request is consistent with Rules 1.5 through 1.11 and 1.13, which specify the procedures for the filing of documents. In addition, this request is consistent with Rules 2.1 through 2.7, which specify general requirements for applications. An officer of PacifiCorp has verified this application as required by Rules 1.11 and 2.1.

C. PROPOSED CATEGORIZATION, NEED FOR HEARING, ISSUES TO BE CONSIDERED, AND PROPOSED SCHEDULE (RULE 2.1 (c))

Rule 2.1(c) requires PacifiCorp to state "[t]he proposed category for the proceeding, the need for hearing, the issues to be considered, and a proposed schedule." PacifiCorp proposes that the Commission classify this proceeding as "ratesetting." The issues in this proceeding relate to PacifiCorp's Distribution Resource Plan submitted in compliance with the ACR.

If no party objects to this Application, hearings may not be necessary. PacifiCorp's Application and supporting exhibits constitute a sufficient record for the Commission to base its decision without the need for hearings. However, PacifiCorp is prepared to provide such other information as the Commission may require during its review of this Application.

PacifiCorp proposes the following schedule, which allows for expedited Commission resolution of the application:

Application filed	July 1, 2015
Protest/Responses to Application	to be determined[3]
Prehearing Conference	August 25, 2015
Scoping Memo	October 1, 2015
Proposed Decision	December 2015
Final Commission Decision	January 2016

D. ORGANIZATION AND QUALIFICATION TO TRANSACT BUSINESS (RULE 2.2)

A certified copy of PacifiCorp's Articles of Incorporation, as amended, and presently in effect, was filed with the Commission in A.97-05-011, which resulted in Commission issuance of D.97-12-093 and is incorporated by reference pursuant to Rule 2.2 of the Commission's Rules of Practice and Procedure.

E. LIST OF EXHIBITS AND APPENDICES

PacifiCorp's Application includes Appendix A, PacifiCorp's Distribution Resource Plan and Appendix B, PacifiCorp's 2015 Smart Grid Annual Report.

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[3] In accordance with the Commission Rules of Practice and Procedure, Rule 2.6(a), a protest or response must be filed within 30 days of the date of the notice of the filing of the application first appears in the Daily Calendar.

III. CONCLUSION

The Company respectfully submits its DRP and requests the Commission approve the DRP as filed.

Respectfully submitted July 1, 2015, at San Francisco, California.

By: Etta Lockey

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VERIFICATION

I am an officer of the applicant in the above-captioned proceeding and am authorized to make this verification on its behalf. The statements in the foregoing document are true on my own knowledge, except as to matters which are stated therein on information or belief, and as to those matters, I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 1, 2015, at Portland, Oregon.

R. Bryce Dalley
Vice President, Regulation

APPENDIX A

PACIFICORP'S DISTRIBUTION RESOURCE PLAN

DISTRIBUTION RESOURCE PLAN

JULY 1, 2015

PacifiCorp d/b/a Pacific Power (U 901-E)

INDEX

I. Background

Assembly Bill (AB) 327, passed in 2013, added Public Utilities Code (PUC) §769 which requires each electrical corporation to a file a distribution resource plan (DRP) no later than July 1, 2015. In August 2014, the California Public Utilities Commission opened rulemaking (R.) 14-08-013 to address the requirements of AB 327. On February 6, 2015, the Commission issued *Assigned Commissioner Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning* (ACR) providing final guidance for the content and structure of the DRPs due July 1, 2015. The ACR provided additional guidance that allows the Small and Multi-Jurisdictional Utilities (SMJU) to submit simplified DRPs no later than July 1, 2015 that address the statutory requirements of PUC §769, but are not required to conform to the DRP Guidance document included with the ACR. PacifiCorp, d/b/a/ Pacific Power (PacifiCorp) is an SMJU and is therefore submitting a simplified DRP in compliance with these requirements.

This DRP will discuss PacifiCorp's distribution system in California, the company's activity in distribution resource planning, particularly as it relates to California planning considerations, and finally it will address the statutory requirements of PUC §769 as required by ACR Ruling Paragraph 3.

II. Approach to PacifiCorp's Simplified Distribution Resource Plan

The guidance in the ACR recommended phase 1 (2016-2017) activities should primarily focus on the evaluation of the capacity of the distribution system to support distributed energy resources under current load forecasting scenarios at the substation level, develop or acquire tools to support the effort, and include analysis and design of system instrumentation to provide input data to distribution system models.

In order to support the company's simplified DRP filing, it was critical to identify the customer served in PacifiCorp's California service territory, the geography of the service territory, load characteristics under a variety of conditions, as well as its experience with the limited distributed generation resources located in its California service territory. On the following pages the company lays out these details, and provides additional information referencing current and potential system distribution plans.

III. Overview of PacifiCorp's California Service Territory and Population Distribution

PacifiCorp is an SMJU that serves 44,732 customer accounts at 48,355 customer locations within northern California. The customer base is comprised of mostly residential customers (79%) with approximately 39% of the residential customers eligible for the California Alternate Rates for

Energy (CARE), a low income discount program available to qualifying households. The company serves a relatively large geographic area of 11,292 square miles, comprised of 75% public and tribal lands. The company has 74 distribution feeders in California with a customer density of 3.99 customers per square mile. Figure 1 depicts PacifiCorp's service territory and its four operating areas in northern California.

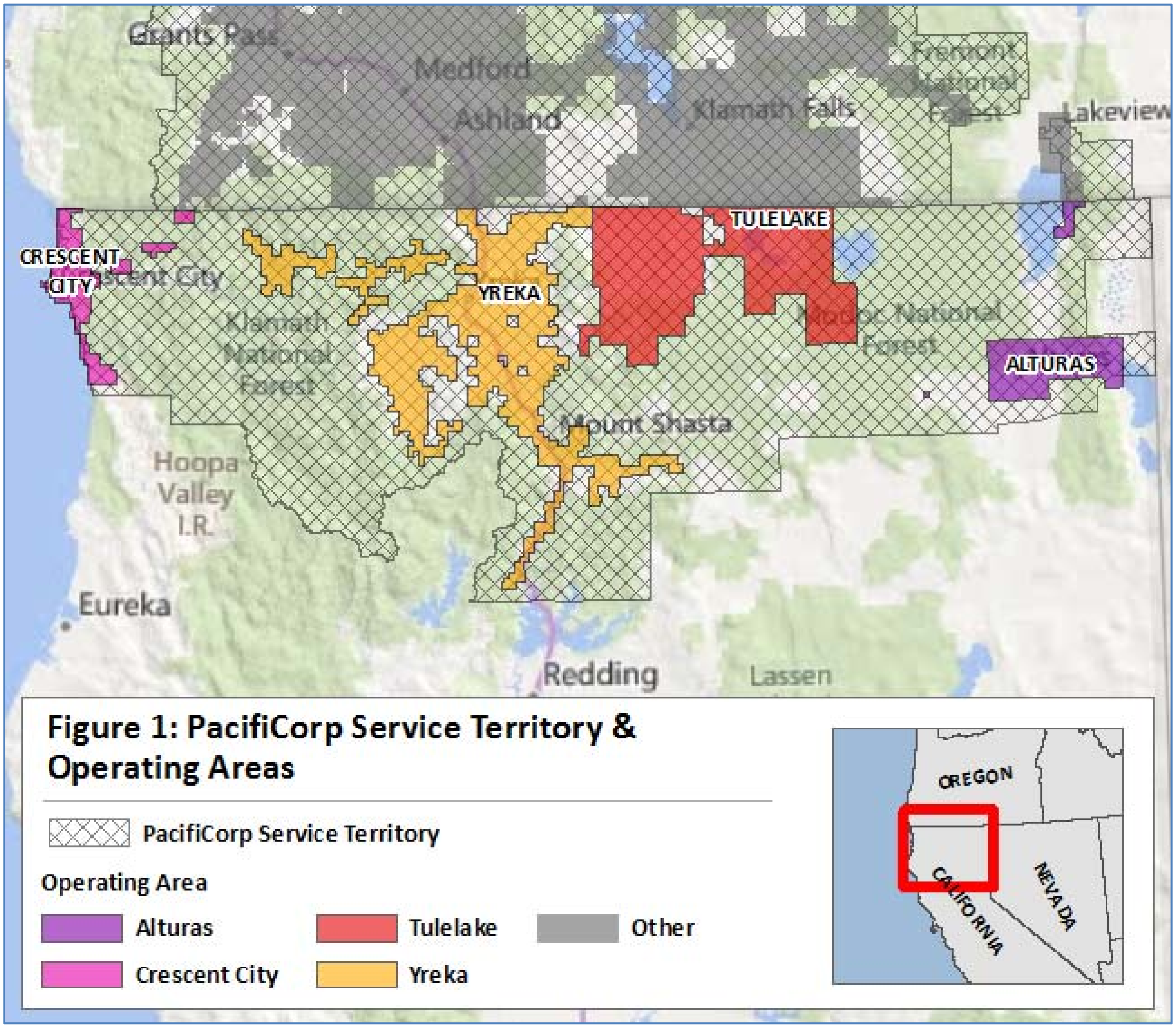


Figure 1: PacifiCorp Service Territory & Operating Areas

Figure 2 represents California's population density,[1] with the green areas designating the highest population density, followed by yellow, then orange, then red, with gray designating areas of very sparse population. Figure 3 displays the four targeted population areas that lay within PacifiCorp's service territory. Dunsmuir is a community served out of the company's Yreka/Mt Shasta area, south of Mt Shasta, adjacent to Interstate 5.

[1] 2010 Census - Census Tract Reference Maps, United States Census Bureau. Available: https://www.census.gov/geo/maps-data/maps/2010tract.html

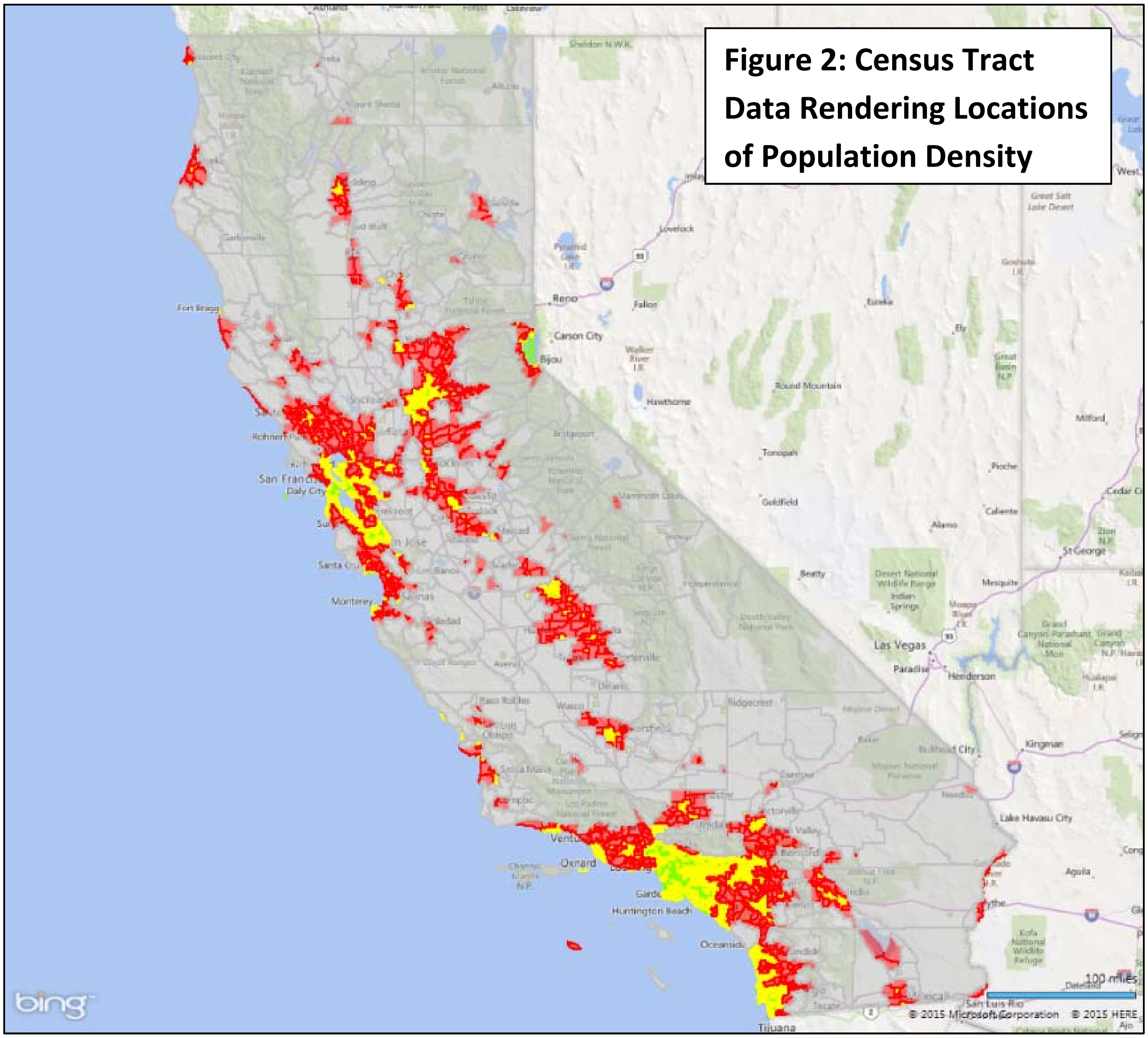


Figure 2: Census Tract Data Rendering Locations of Population Density

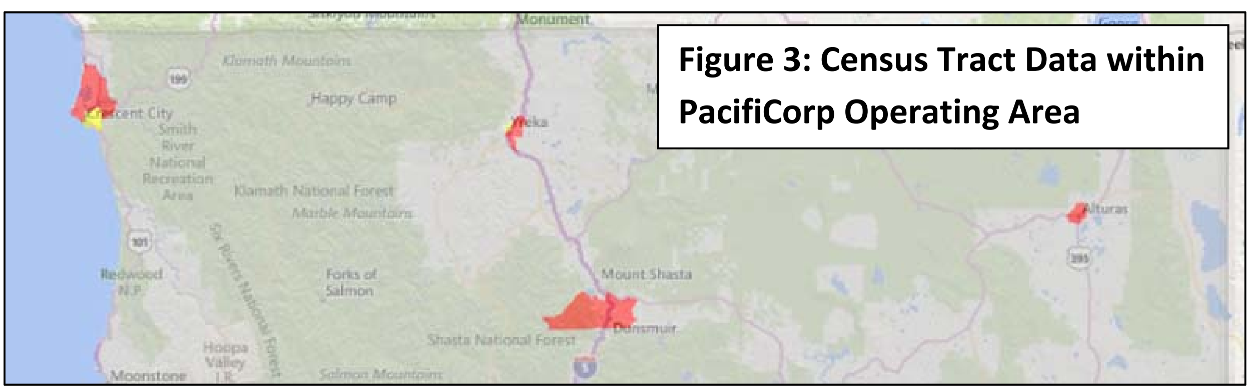


Figure 3: Census Tract Data within PacifiCorp Operating Area

IV. Solar Photovoltaic Analysis and System Load Impacts

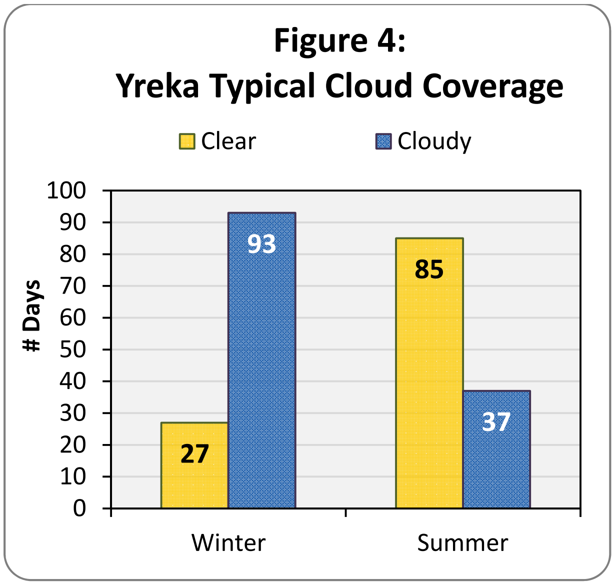
In recent years, the expansion and advancements in alternative Distribution Energy Resources (DER) has created increased opportunity to integrate non-utility owned generation source energy into the system. Residential photovoltaic systems are a primary example of a DER. Given the geographic footprint of the state and the azimuthal location, this sector comprises the largest potential generation growth in California. The following information analyzes PacifiCorp's current use and integration of solar generation as it applies to seasonal substation load. This approach was taken to align with the distributed generation penetration forecast models in the company's 2015 Integrated Resource Plan (IRP). To recognize the value of this resource into the plan, it is important to consider some generation basics. These concepts are outlined and explored further below.

The uncertainty of solar generation placement within the network is reliant on several factors that are critical to its value and economics.

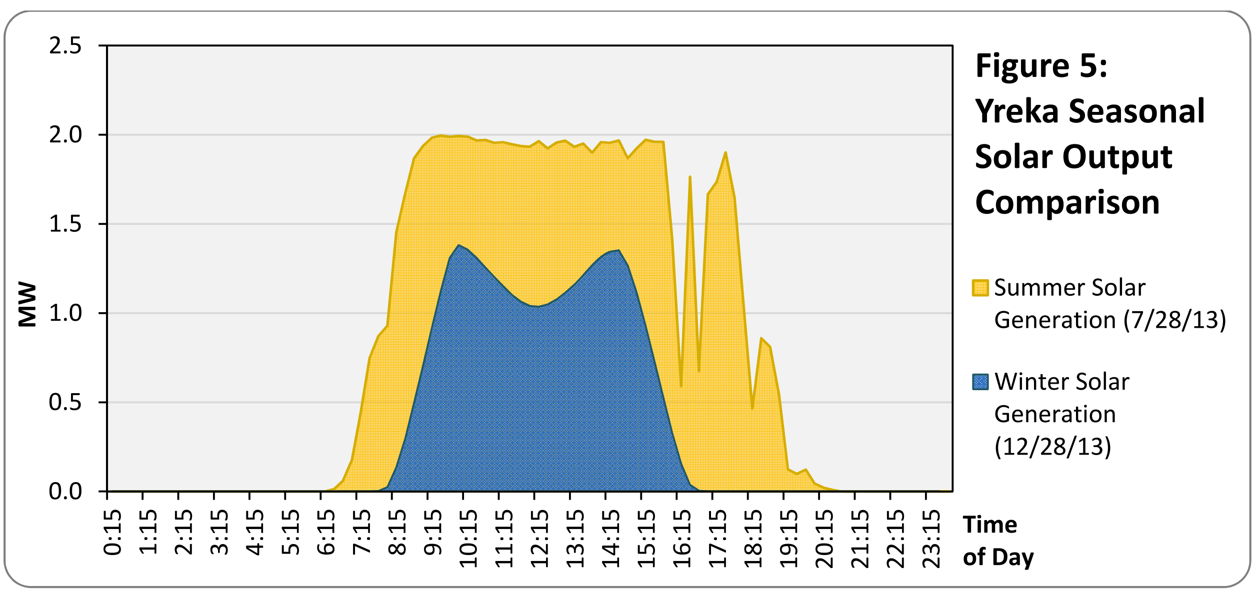
1) Solar generation is reliant on clear days, thus, how probable is it that clear days occur such that generation probability is high, both for winter and summer cases?
2) Output capacity of solar generators are dependent upon a variety of factors, including alignment toward the sun, such that even during a peak day (summer and winter) it's key to know what amount of installed capacity can be expected to be realized when aligned with both winter and summer peak uses?
3) Output capacity as a function of the time of day varies with the equipment's alignment to the sun, so the production profile varies within the day and must be compared against the generator's usage profile, to answer whether the likelihood of the solar resource contributes significantly to total energy produced in addition to production during either generation or capacity peak hours?

In order to answer the first of these questions, weather data was evaluated for northern California, specifically Yreka. Sources indicate that, in general, for about 1/3 of the year the area experiences "clear days". This data, considered during winter (November-February) and summer (June-September) is shown in Figure 4 below.[2] It is important to note that this area of California is a winter peaking system; it experiences the highest total energy needs and highest instantaneous energy demands during the winter.

[2] Weather History 30 year averages for Yreka, California, National Oceanic and Atmospheric Administration. Available: http://alltowndata.com/living-in/Yreka-California



As stated previously, solar generation output varies based on a variety of factors, including the azimuthal angle. Thus, unless the units are able to rotate or are placed to maximize winter output, there will be output reduction that occurs in the winter, assuming the units have been placed to generate the maximum production output for the summertime (since the number of days that clear skies are probable would lead to such placement). Again, this area experiences its highest energy use during the winter months. Figure 5 demonstrates the effective output of a 2 megawatt unit with single axis tracking during both winter and summer months.[3] In order to deliver optimally to a winter peaking system, summer installed capacity might be elevated, but if placed on a system with minimum loading constraints, could be restricted in its production.



[3] Production data utilized from PacifiCorp's Black Cap Solar facility located near Lakeview, Oregon.

Initial screening of available load data was analyzed at the substation level to establish viable areas. Based on the traditional screens for residential photovoltaic penetration, the company could accommodate between 31.1 MW and 52.2 MW depending on whether the peak load criteria or the minimum daytime load criteria is utilized; further assuming that all distribution line segments are able to be fully loaded with solar demands. This analysis was refined to target the four population centers previously identified. The company has supervisory control and data acquisition (SCADA) on 16% (or 12 circuits) of the (74) distribution feeders; the remaining feeders are not outfitted with these devices, and currently rely upon manual reads for planning purposes. Crescent City and Alturas were excluded after the initial analysis because time of day-based load information was not available. The Yreka and Dunsmuir areas represent a total opportunity of approximately 4.7 MW (at 15% of peak load) or 9.6 MW (at 100% minimum daytime loading). It was observed that the DER could contribute to reducing peak on a limited number of days. Figure 6 demonstrates the actual load for a substation on December 28, 2013 and models the output of the nearby 2 MW solar installation. December 28, 2013 was selected as a peak load day; it's worth noting that actual conditions on this peak day were cloudy and foggy, which would suggest that while solar input is modeled on the chart below, that resource would likely not have been realized on that day.

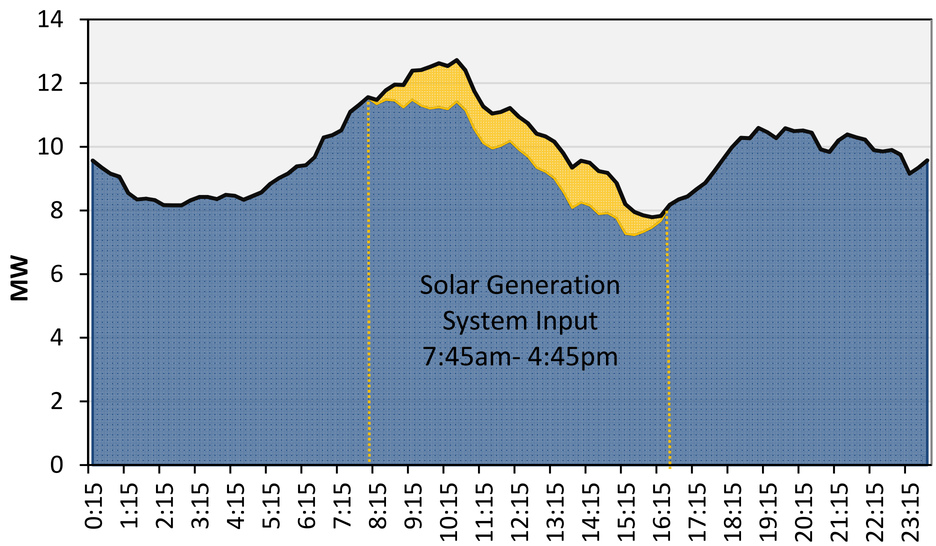
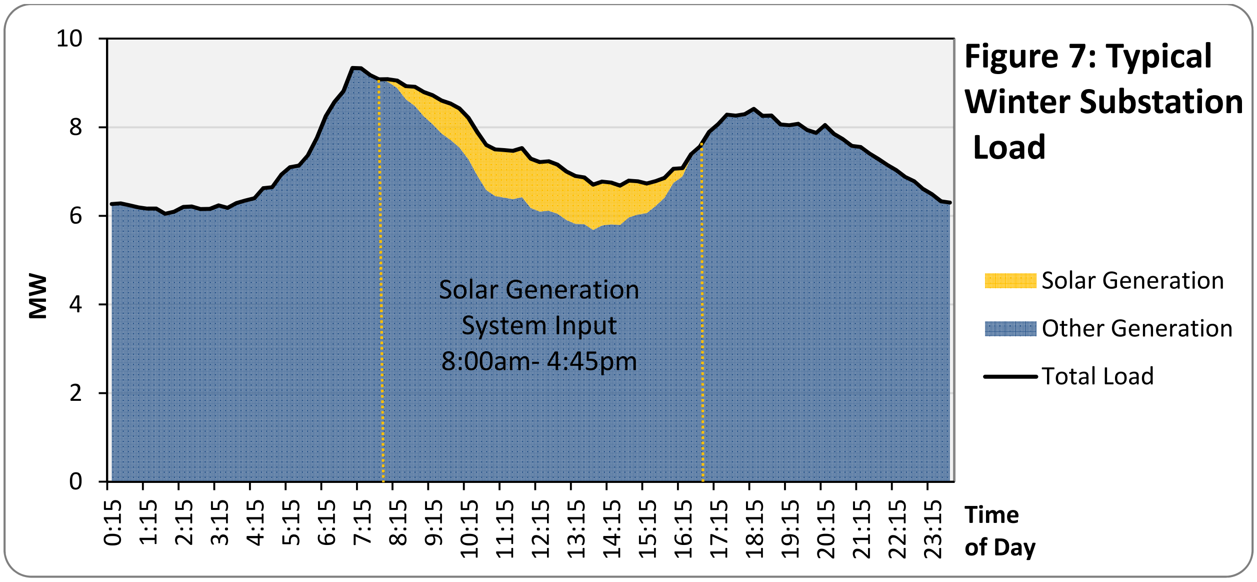
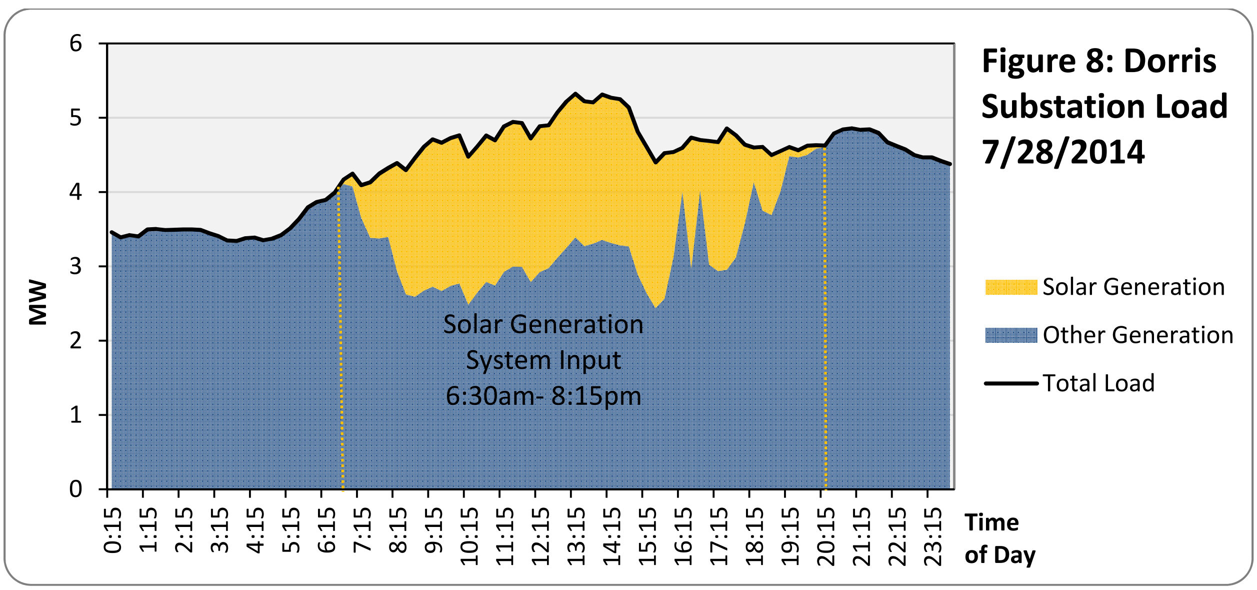


Figure 6: Yreka Substation Load 12/28/2013

In the Yreka area, the substations analyzed had a winter daily peak that occurred before sunrise or after sunset 81% of the time. In the Dunsmuir area, the winter daily peak occurred before sunrise or after sunset 57% of the time. Figure 7 demonstrates a peak occurring before sunrise. Residential photovoltaic installations would need to dramatically change to contribute to a reduction in winter peak demand on the electrical infrastructure in the area PacifiCorp serves.



Outside of the initial screening criteria regarding population centers, a summer peaking substation with available time of day-based load data was also analyzed, also on a peak day. It was observed for this specific substation that the summer peak occurred before sunrise or after sunset only 6% of the time, for which it can be concluded that solar resources can have benefit during certain times of the day; note that after dark an elevated value, quite close to daily peak is also present. However, it is notable that during this day the sky was clear and solar resources would be able to produce throughout daylight hours.



V. Current Plan Review

The company also reviewed current distribution planning studies for the Yreka and Dunsmuir areas. The Yreka distribution planning study, completed at the end of 2014, contains one potential distribution infrastructure improvement project that is in monitor status and not yet required to be constructed. The company will continue to monitor this project and evaluate cost-effective alternatives as the project becomes more imminent. The Dunsmuir area study was completed in 2015 and has no distribution infrastructure improvement projects identified.

VI. System Interconnection and Decentralization

The company utilized existing modeling tools to create a sample map of potential viable interconnection locations on a feeder. The evaluation criteria were based off of the Federal Energy Regulatory Commission small generator interconnection procedures definition of mainline within the fast track screening process.[4] Figure 9 show an example of distribution "Mainline" connection. The mainline is designated by the green line, while other circuit elements are shown with orange and magenta line colors. This graphic demonstrates that a small portion of any given circuit may be currently constructed in a manner conducive to generator interconnection.

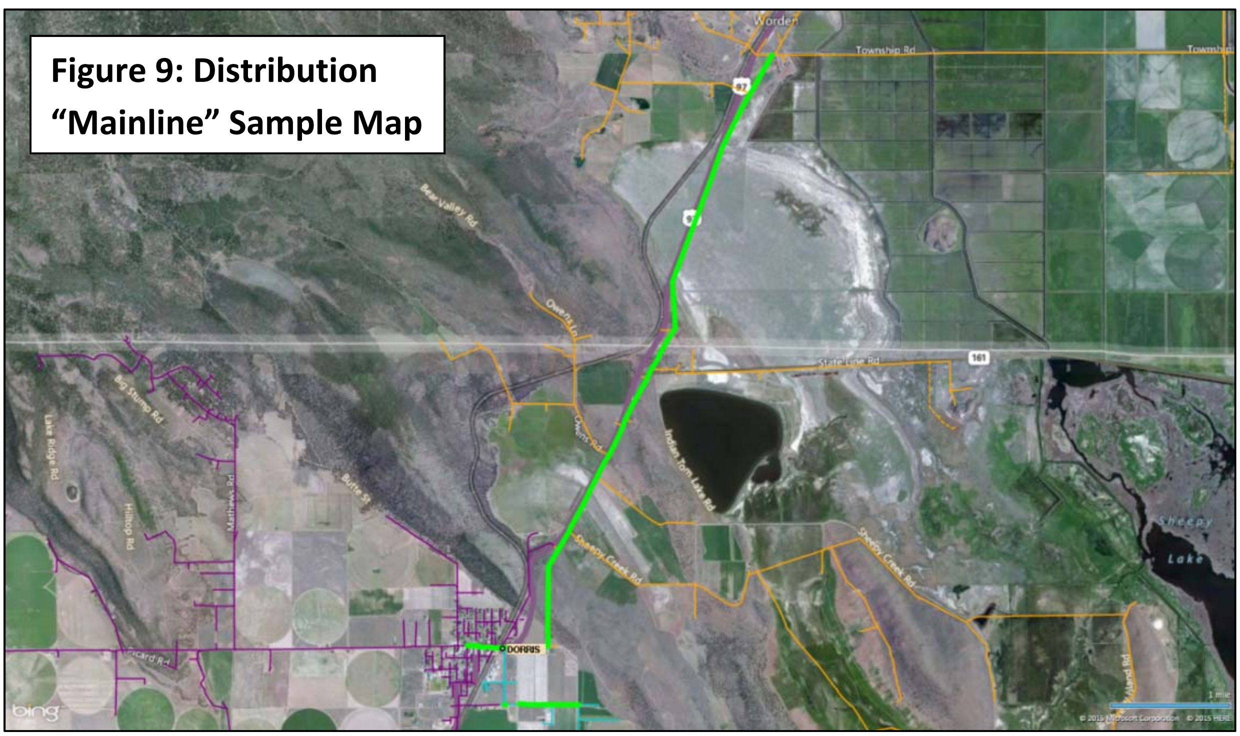


Figure 9: Distribution "Mainline" Sample Map

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[4] Small Generator Interconnection Procedures, Federal Energy Regulatory Commission. (2014, Sept). Avabilable: http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

VII. Statutory Requirements

In accordance with ACR Ruling Paragraph 3, PacifiCorp addresses the following statutory requirements contained in PUC §769:

(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation.

On March 31, 2015 PacifiCorp filed 2015 IRP. The IRP shows that PacifiCorp's resource needs can be met with demand side management (DSM) and short-term firm market purchases through 2027. New to the 2015 IRP was a supplemental study prepared by Navigant Consulting, Inc. which produced generation penetration forecasts for solar photovoltaic, small scale wind, small scale hydro, combined heat and power reciprocating engines, and combined heat and power micro-turbines specific to PacifiCorp's service territory. The distributed generation forecasts from this study are applied as a reduction to forecast load in the IRP modeling process. The study also addressed market potential and barriers. PacifiCorp's IRP and associated documents are located at: https://www.pacificpower.net/about/irp.html. Also refer to sections III – VI of this DRP.

(2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

After the initial screening, the company does not have any specific proposals for California at this time. On May 27, 2015 PacifiCorp issued the 2015 Solar Request for Proposals. The RFP seeks Utah solar photovoltaic generation resources of up to fifteen megawatts alternating current that are compliant with existing or anticipated renewable portfolio standard requirements. The project is designed to support Utah customers that wish to buy the output from Utah based solar photovoltaic resources to meet a portion of their energy requirements. The company will evaluate this pilot program in phase 1 of the DRP to determine the applicability and benefits of the subscriber solar program for its customers in California.

(3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

The company does not have any specific proposals at this time. PacifiCorp's California Solar Incentive Program (CSIP) is currently in step six of seven, for residential and non-residential systems with an incentive rate of $0.47 per watt. Since the program began in

2011, PacifiCorp has interconnected 139 CSIP participants for a total of 2.72 MW of installed solar generation. The company has a total of 187 net metered customers representing only 0.387% of the customer base. The company will continue to monitor Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric's DRP applications, including their experiences with pilot projects, to determine applicability within PacifiCorp's service area.

(4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

In 2013, PacifiCorp initiated a project to replace its distribution power flow software with project completion expected in 2015. In phase 1 of the DRP, the company will evaluate additional capabilities provided by the software; evaluate additional tools and software to further enable studying DER and evaluate tools utilized or developed by other California investor owned utilities for applicability to PacifiCorp's California customers and its network in the interest of yielding net benefit for its customers in the distribution planning process.

(5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

Technology is rapidly evolving for DER and the standards that support it. The integration of a resource onto the distribution system requires enabling technologies including time-specific data for weather, customer uses, and system loading and generator output, and relies upon load modeling and various statistical/probabilistic tools, combined with an extremely sophisticated set of rules required in order to establish proper safety and reliability for the system. PacifiCorp Policy 138, Distributed Energy Resource Interconnection Policy explains the technical requirements for the interconnection of generators to PacifiCorp's distribution system. The most recent version of the policy is available at: http://idoc.pacificorp.us/content/dam/intranet/doc/ap/policies_and_procedures/eamp/distribution/fpp/oh/138.pdf .

In addition, the company refreshes its view of smart grid technologies and annually updates its Smart Grid Report.[5] This report focuses on technologies that can be readily integrated with the existing electrical grid infrastructure. Technologies studied include advanced metering systems with demand response programs, distribution management systems, transmission synchrophasors, distributed energy systems, direct load control programs, and fully redundant distribution systems. A copy of the 2015 version of the Smart Grid Report is included in Appendix B for information purposes only. The

[5] PacifiCorp was dismissed as a party to the smart grid proceeding in California (R.08-12-009) and is not required to file an annual smart grid report with the CPUC. PacifiCorp's annual smart grid report is prepared in compliance with requirements in other states served by PacifiCorp.

company will continue to monitor technologies and collaborate with the utility industry to adapt to the new technologies as they unfold.

APPENDIX B

2015 SMART GRID ANNUAL REPORT

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Smart Grid Annual Report

July 1, 2015

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Executive Summary

This 2015 Annual Smart Grid Report (Smart Grid Report) is an update to the 2014 Smart Grid Report. Smart grid is the application of advanced communications and controls to the power system, from generation, through transmission and distribution, to the customer. As a result, a wide array of applications can be defined under the smart grid umbrella. This Smart Grid Report focuses on technologies that can be readily integrated in a cost-effective manner with the existing electrical grid infrastructure.

A business case analysis was performed to examine the quantifiable costs and benefits of a comprehensive smart grid system, as well as each individual component. The net present value of implementing a comprehensive smart grid system throughout PacifiCorp is negative at this time. However, PacifiCorp has implemented specific projects and programs that have a positive benefit for our customers, and explored pilot projects in other areas of interest.

A key effort at PacifiCorp this past year included developing a detailed analysis and business case for advanced metering technologies (AMI), including information technology systems that support AMI, in the Oregon service territory. This effort consisted of identifying quantifiable benefits and costs associated with a prudent staging of investments to mitigate customer rate pressures. Due to a wide variation in manufacturer-provided budgetary cost data, a request for proposal was issued to all major metering system vendors to obtain precise fixed costs. Proposals were evaluated, and the financial analysis showed a marginally positive business case when considering AMI as a stand-alone application. However, when full consideration is given to an overarching replacement strategy to address future obsolescence of IT supporting programs, such as the customer information system, an economic and compelling business case cannot be made for implementing AMI at this time.

Smart Grid Strategies, Objectives, and Goals

The purpose of the 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 potential roadmap for the future is presented at the end of this report, which aligns the relative start dates for various components in order to give an understanding of the progress required to reach a full smart grid deployment with an aggressive schedule. However, the starting date and schedule of progression of any effort must be driven by the fundamental economics laid out in a financial analysis in order to protect the Company and its customers' best interests.

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

- Ensure that smart grid investments provide service at reasonable and fair prices by comparing products and solutions 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.
- Work with manufacturers to discuss smart grid products and determine their applicability to PacifiCorp's system.
- Research industry projects and work with organizations, such as the National Electric Energy Testing Research and Applications Center, in order to enhance PacifiCorp's understanding of smart grid technologies.

The following short-term objectives have been identified as part of the smart grid efforts at PacifiCorp.

- Continually improve customer relations through customer communications and web portal work, and
- Enhance the meter data management system implemented to become a scalable future smart grid data throughput platform, targeting completion by Q2, 2016.

By implementing the objectives mentioned above, the Company expects to be able to reach the following long-term smart grid goals.

- Increase customer awareness and understanding of how the electric system works and how electricity usage impacts and drives Company investments and operations.
- Give customers tools that may be used to change their electricity usage for their benefit.
- Optimize PacifiCorp's electric system through the application of cost-effective smart grid technologies.

PacifiCorp seeks to leverage smart grid technologies in a way that aligns with the integrated resource plan goals and optimizes the electrical grid when and where it is economically feasible, operationally beneficial, and in the best interest of customers. This overall goal aligns with state commissions, whose goals include improving reliability, increasing energy efficiency, enhancing customer service, and integrating renewable resources. These goals will be met by utilizing strategies that analyze total cost of ownership, performing well-researched cost benefit analyses, and focusing on customer outreach.

Projects Overview

PacifiCorp has implemented a number of smart grid-related projects and programs. These projects are chosen based on analysis of their ability to cost-effectively improve service to the Company's customers. These projects can apply to any sector of the power system, which synergistically support a smart grid concept, depicted in Figure 1.

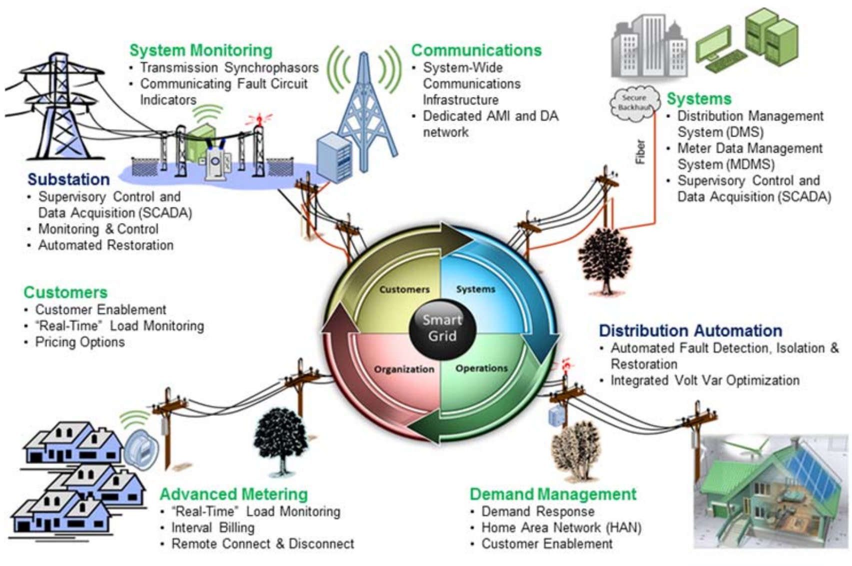

Figure 1 – Select Smart Grid Components

Many of the smart grid technologies are dependent upon preceding technology deployment for the full benefit. As illustrated in Figure 2, all applications depend upon a wide area network for full functionality.

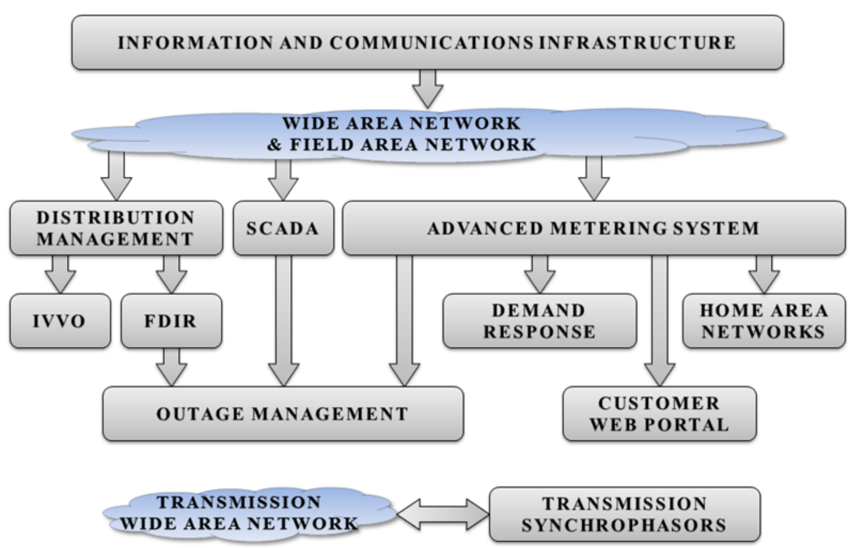

Figure 2 – Smart Grid Technology Dependencies

The following section describes the individual projects, programs, and efforts in detail. These are displayed spatially in Figure 3.

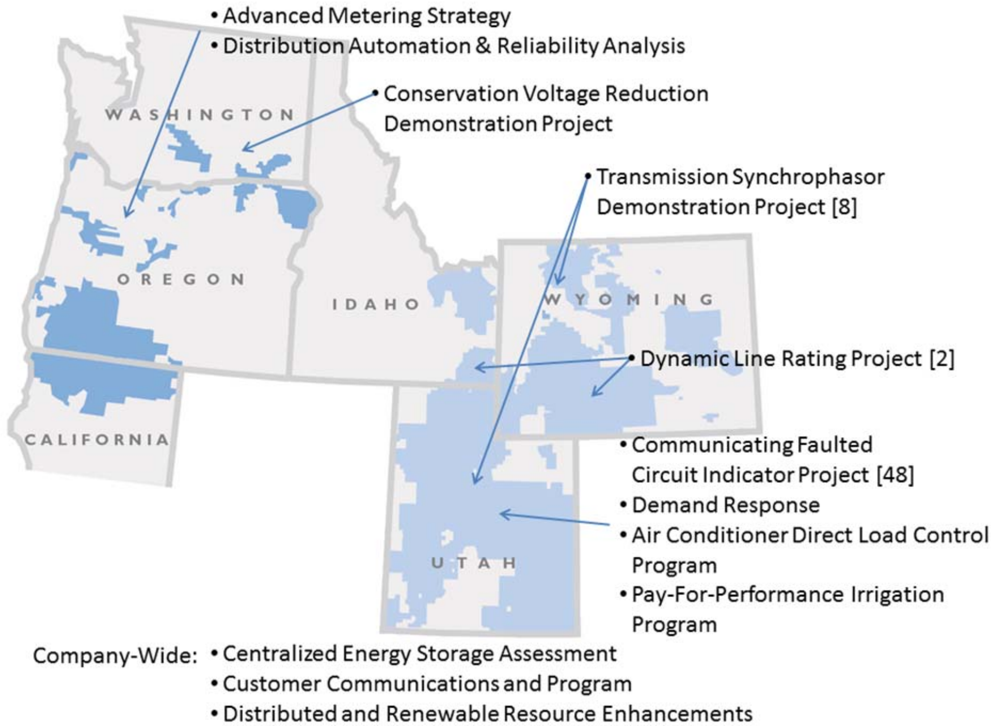

Figure 3 – PacifiCorp Smart Grid Projects

Project status and timeline is summarized in Table 1.

Table 1 – Summary of Projects

Project	Status	Timeline
Dynamic Line Rating	Miners-Platte project is complete. Second project, West-of-Populus, is ongoing.	West-of-Populus project fully functional; evaluation expected 2016.
Transmission Synchrophasor Demonstration	PacifiCorp's Western Interconnection Synchrophasor Project responsibilities complete. Currently engaged in evaluation of model validation process.	Awaiting data access from WECC; expected 2015. Model validation evaluation; expected 2016.
Centralized Energy Storage Assessment	Complete.	N/A
Communicating Faulted Circuit Indicators	Engaged in ongoing validation and analysis.	Validation and analysis; expected 2016.
Distribution Automation & Reliability Analysis	Complete.	N/A
Conservation Voltage Reduction Demonstration	Complete.	N/A
Advanced Metering Strategy for Oregon Customers	Ongoing business case analysis.	See figures 6 and 7 for illustrative timeline.
Customer Communications and Programs	Complete.	N/A
Demand Response – OR Pilot Irrigation	Initiation.	Expected 2017.
Distributed and Renewable Resource Enhancements	Complete.	N/A

Projects 1: Transmission Network and Operations Enhancements

Dynamic Line Rating Project

Dynamic line rating (DLR) systems utilize sensors to monitor the conditions that impact the real-time temperature of a transmission line or lines, and use this measured data to calculate the real-time thermal capability of the lines. Transmission line capability is generally limited by conductor temperature. As transmission line conductor temperature rises, the metal conductor becomes more ductile, and the line sags closer to the ground. There are several factors that influence conductor temperature, most notably line current, wind speed, wind direction relative to conductor, and ambient temperature. As ground clearance is a public safety concern, transmission lines are typically rated utilizing assumptions of worst-case ambient weather conditions for a given season (for example, the hottest anticipated summer day with the lowest anticipated wind speed). These worst-case assumptions allow utilities to safely operate their systems through changing weather conditions. However, as the worst-case conditions are only seen for a small fraction of a given season, existing transmission infrastructure often has a large thermal reserve that is not utilized. Dynamic line rating systems allow utilities to utilize this available thermal capacity during times when weather conditions are favorable to conductor cooling.

DLR systems provide a benefit where conductor thermal performance is the limiting element on a given line or transmission path, and DLR systems do not provide benefits in areas where system voltage or other constraints limit the capability of a given portion of the transmission system. Additionally, scheduling intervals must be sufficiently short to allow the dynamic line rating systems to provide a stable real-time rating over the scheduling interval. In the event that line load or schedule exceeds the real-time rating of a line, operator interventions are required to keep the conductor temperature within operating limits that do not jeopardize public safety. These factors limit the applicability of DLR technology on the transmission system. In some cases, DLR technology can provide significant benefit with minimal risk to safe operation of the transmission system.

The primary case where DLR technology is considered viable is in areas of the system where transmission line loading correlates well with output from wind generation facilities that are geographically close to the line. In these areas of the system, line loading tends to increase or decrease in conjunction with the real-time thermal capability of the line. The Miners-Platte DLR Pilot Project is an example of this system condition, and the project benefits have been significant.

<u>Project Summary</u>
Two dynamic line rating projects were implemented in 2014. One project, Miners-Platte, is operational. The other project, West-of-Populus, requires further data collection and analysis. West-of-Populus is planned to be operational in 2016.

Project Description and Analysis

PacifiCorp identified two locations within its transmission system where real-time dynamic thermal line rating systems offered potential benefits. These locations were identified as needing transmission expansion during PacifiCorp's normal transmission planning process, and dynamic line rating was determined to be an applicable solution (e.g. the transmission was thermally constrained, and the time periods and capacities required were coincidental with that made available with dynamic line rating).

Table 2 – DLR Activity Timeline

Activity	**Time Period**
Miners-Platte	
Equipment Installation	Early 2012
Data Collection & Analysis	Summer 2012
Ratings Process	Mid-2012 – Mid-2013
In Service	Completed
West-of-Populus	
Equipment Installation	2013
Data Collection	2013 – ongoing
Ratings Process	2016
In Service	Expected 2016, dependent on analysis and quality of data

The first location selected for installation of dynamic line rating equipment is a 31-mile section of a 230 kV transmission line between Miners and Platte substations in south-central Wyoming. The steady-state thermal rating of this particular line segment was one of the limitations on the Western Electricity Coordinating Council (WECC) TOT4A transmission path, and multiple wind farms impact the loading of the line segment. The second location selected for installation of dynamic line rating equipment is three 345 kV transmission lines west of Populus substation in southeast Idaho with a combined length of 147 miles. In this particular installation, the system capacity of West-of-Populus is limited by post-contingency loading of one of the lines following the loss of the other two. Refer to Figure 4 (left) for a simplified map of the 230 kV system in south-central Wyoming where the Miners-Platte dynamic line rating system was installed. Refer to Figure 4 (right) for a map of the 345 kV transmission system near Populus substation, where the West-of-Populus dynamic line rating system was installed.

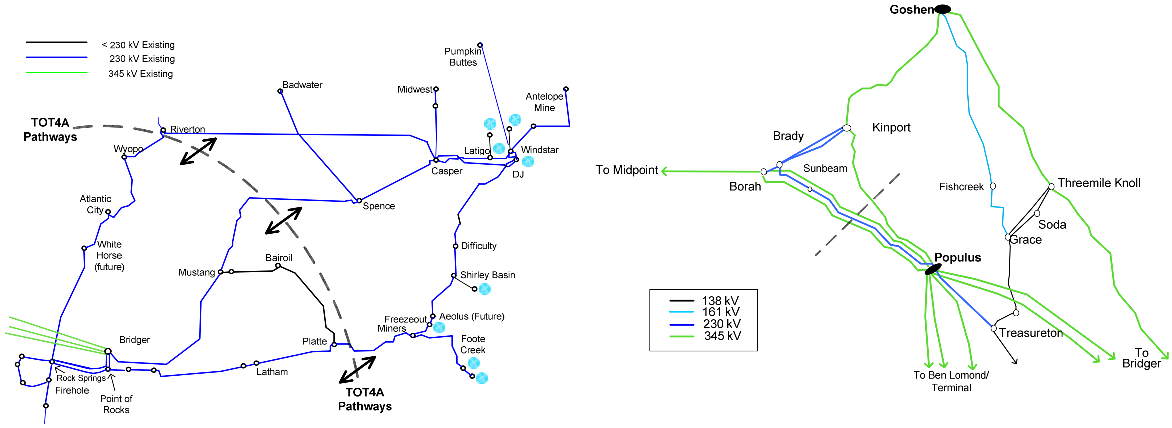

Figure 4 – (Left) TOT4A and the Southern-Wyoming 230 kV Transmission System. (Right) Simplified Transmission System near Populus Substation.

PacifiCorp selected the CAT-1 line monitoring system offered by The Valley Group for both projects. The CAT-1 system calculates real-time line ratings 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. The master station processes the measurement data and communicates line ratings and other system information to the Company dispatch center. The information is converted to a screen display that shows the real-time maximum rating of the line, thereby enabling dispatch decisions utilizing the real-time thermal capability of the line.

The Miners-Platte installation is complete and in-service. System studies were completed to determine the project benefits and the TOT4A WECC path rating was increased. The maximum non-simultaneous TOT4A path rating was increased from 810 megawatts (MW) to 960 megawatts as a result of the dynamic line rating system in conjunction with other system improvements. Additional system improvements installed in 2014 have allowed the maximum non-simultaneous TOT4A path rating to increase to 1025 MW. Real-time operating limits of the TOT4A path are determined in conjunction with loading on the adjacent TOT4B WECC path, however the TOT4A capacity increase resulting from the dynamic line rating installation at typical TOT4B load levels exceeds 100 megawatts. Refer to Figure 5 for the current TOT4A / TOT4B operating nomogram. The dynamic line rating system benefits are limited to the winter static operating nomogram to prevent operation of the system above voltage limitations on the path. Therefore, the winter static curve in Figure 5 is representative of the maximum possible benefit from the Miners-Platte dynamic line rating system without further transmission improvements.

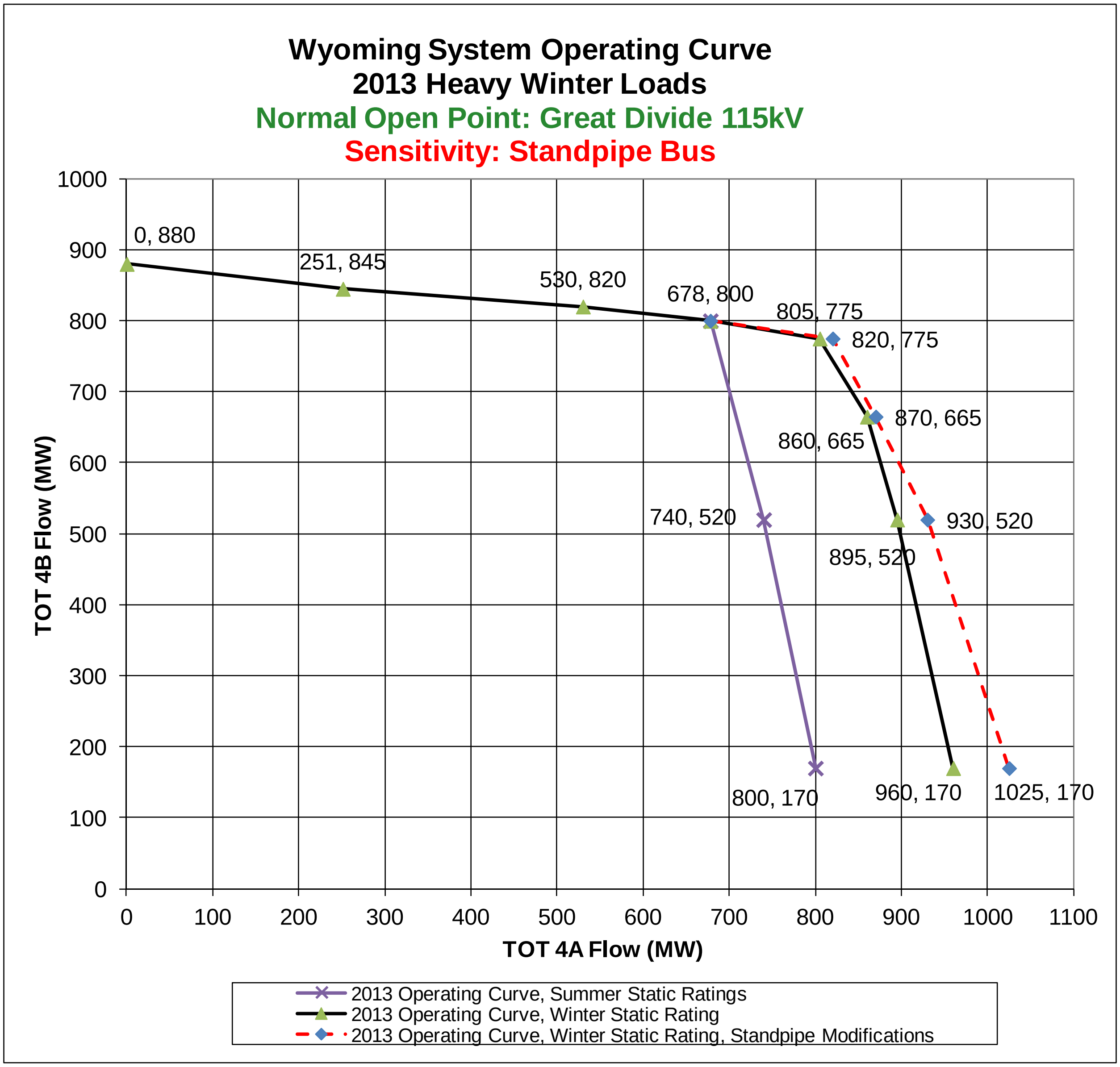

Figure 5 – TOT4A/TOT4B Nomogram

The DLR installation on the 345 kV lines west of Populus is currently in a data collection and analysis phase to determine an optimal strategy to incorporate the system into real-time operations. Hardware installation is complete at this time, and the system is reporting real-time line ratings. Limited summer operating data is available from the system, however line modifications to remediate line clearance issues found during LiDAR surveys of the lines have resulted in an extended calibration period of the DLR system. Additionally, pending changes to the WECC regional criteria governing multiple contingency definitions have eliminated one of the critical outages that limited the capability of the transmission system west of Populus. PacifiCorp is currently exploring incorporation of the DLR data into the Jim Bridger Remedial Action Scheme (RAS) to limit arming conditions and generation exposure to tripping from the RAS.

Future Actions

Further analysis is necessary on the West-of-Populus dynamic line rating system to determine an optimal strategy to incorporate the system into real-time operations. This effort will be completed and operational in 2016.

Dynamic line rating is considered for future transmission needs. Dynamic line rating is only applicable for thermal constraints and provides capacity only during site-dependent time periods, which may or may not align with the expected transmission need. Dynamic line rating is one method within the toolbox of transmission planning and is considered when applicable.

Transmission Synchrophasor Demonstration Project

Transmission synchrophasors, also called phasor measurement units (PMUs), can lead to a more reliable network by comparing phase angles of certain network elements with a base element measurement[1]. 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 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 WECC. PMU implementation and further development may enable transmission operators to integrate variable resources and energy storage into their balancing areas more effectively and minimize service disruptions. A self-healing transmission grid would reduce outages by "detouring" energy to other paths with available capacity.

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 may not be facilitated by the synchrophasor program as envisioned in prior reports. Further research may reveal 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.

Project Summary

PacifiCorp and other participating utilities have completed installation of eight PMUs at eight substations and have data streaming to WECC since 2013. While utility responsibilities are complete, WECC and Peak Reliability are continuing to develop data access for utility participants. The system of synchrophasors will support WECC and Peak Reliability in the

[1] U.S. Energy Information Administration. (2012, Mar. 30). *New technology can improve electric power system efficiency and reliability* [Online]. Available: http://www.eia.gov/todayinenergy/detail.cfm?id=5630.

prevention of system blackouts, as well as provide historical data for the analysis of any future power system failure. The data may prove useful for utility operations in the future.

Project Description and Analysis

PacifiCorp participated in the WECC Western Interconnection Synchrophasor Project,[2] a collaborative effort among partners throughout the U.S. portion of the Western Interconnection. The project will support WECC and Peak Reliability, which was formed through a division of WECC, to maintain the stability of the power system. The synchrophasors will be used by WECC and 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. PacifiCorp completed installation of PMU equipment at eight substations:

- Camp Williams (Utah)
- Emery (Utah)
- Mona (Utah)
- Populus (Utah)
- Dave Johnston (Wyoming)
- Jim Bridger (Wyoming)
- Monument (Wyoming)
- Wyodak (Wyoming)

PacifiCorp also installed two phasor data concentrators at the PacifiCorp Salt Lake City control center, which are capable of streaming data to WECC and Peak Reliability. The phasor data concentrators collect and archive real-time data streams from remote substation site PMU equipment and transmit the real-time data to WECC in Vancouver, Washington.

WECC has developed the "wide area view" tool[3] to enable situational awareness. The wide area view tool can allow users to see all of the connected participating PMU sites in the Western Interconnection and any available real-time data that they provide. The wide area view tool has been live since 2013,[4] but only limited data from a small number of sites are available.

Peak Reliability is continuing to work to "improve the quality and use of the synchrophasor data it receives." Peak Reliability will work to improve grid performance in the following five focus areas:

1. Manage and improve data quality;

[2] U.S. Department of Energy. *Western Electricity Coordinating Council: Western Interconnection Synchrophasor Program* [Online]. Available: https://www.smartgrid.gov/project/western_electricity_coordinating_council_western_interconnection_synchrophasor_program

[3] Peak Reliability. *WAV* [Online]. Available: https://www.peakrc.org/Realtime/Pages/WAV.aspx

[4] WECC. *WECC Newsletter October 2013*.

2. Correlate synchrophasor measurements with interconnection behavior and performance;
3. Integrate application results with operational documentations/procedures;
4. Deploy automatic controls; and
5. Make data availability efficiency improvements, including employing a more efficient and reliable system for distributing synchrophasor data."[5]

More specifically, Peak Reliability is exploring the use of synchrophasor data for:

- Voltage stability analysis and visualization
- Frequency Oscillation detection
- Mode analysis and visualization, mode alarms
- Phase angle monitoring
- Interconnection PMU and signal registry
- Interconnection wise area visualization
- State estimator validation

PacifiCorp will continue to work with Peak Reliability to determine how to best use the available PMU data for situational awareness using the Peak Reliability wide area view tool or an in-house tool.

One of the applications for PMU technology being evaluated by PacifiCorp is the benchmarking, validation, and fine tuning of system planning models[6]. It is proposed that by utilizing PMU data collected during actual switching or disturbance events, system planners can compare system model outputs to actual system reaction. Differences in the model output and actual data can then be leveraged to fine tune model input parameters, thus theoretically improving subsequent model simulations.

Future Actions and Timeline

While WECC and Peak Reliability responsibilities of the Western Interconnection Synchrophasor Project are ongoing, the data may prove useful for utility operations in the future, i.e. the benchmarking and model validation proposal. At present, PacifiCorp has no plan to implement more synchrophasors; additional installation will be considered after the Western Interconnection Synchrophasor Project proves fruitful.

The 2016 report will provide an update on the benchmarking, validation and fine tuning of system model evaluation.

[5] Peak Reliability. *Peak Reliability June 13, 2014 Release* [Online]. Available: https://www.peakrc.com/Business/Press%20Release%20Peak-DOE%2006-13-2014%20Final%20.pdf
[6] Srdjan Skok, Member, IEEE. *Applications Based on PMU Technology for Improved Power System Utilization*.

Projects 2: Substation and Distribution Network and Operations Enhancements

Substation and distribution projects include centralized energy storage, communicating faulted circuit indicators, distribution automation, operational management systems, conservation voltage reduction, and integrated volt/var optimization.

Centralized Energy Storage Assessment

Centralized energy storage (CES) includes but is not limited to large, centralized storage resources, such as electrochemical batteries, pumped hydro, and electromechanical batteries (i.e., flywheels). One of the benefits of the smart grid is the ability to integrate renewable energy sources into an electricity delivery system. In contrast to dispatchable resources that are available on demand, such as most fossil fuel generation, some renewable energy resources have intermittent generation output due to their fuel source of wind or photovoltaic solar. The generation output of these resources cannot be increased and has high opportunity costs when generation is decreased. Providing service to the electrical grid becomes increasingly challenging as the amount of the grid's energy requirements are served more and more from these intermittent resources. Two methods to fill this generation gap without the use of dispatchable resources are demand response (DR) programs and centralized and/or localized energy storage.

<u>Project Summary</u>
PacifiCorp completed an energy storage screening study in support of integrated resource planning.

<u>Project Description and Analysis</u>
As part of integrated resource planning, PacifiCorp commissioned an energy storage screening study, which was completed in December 2011 and updated in July 2014. The study provides a current catalog of commercially available energy storage technologies.[7]

In 2013, PacifiCorp analyzed various centralized energy storage systems to study their effectiveness in improving asset utilization as well as transmission and distribution 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 transmission and distribution upgrade deferral, multiple substation storage devices in a single substation or multiple substations would be required. Furthermore, centralized energy storage devices do not necessarily provide benefits to reduce future circuit infrastructure. On the other hand, localized energy storage technology (in which storage units are placed downstream from substations)

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[7] HDR Engineering, Inc. *Update to Energy Storage Screening Study for Integrating Variable Energy Resources within the PacifiCorp System* [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Energy_Storage-Screening-Study-July2014.pdf

provides the most benefit in avoided future infrastructure. However, in coordination with PacifiCorp's current subdivision design standards that 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 kilowatt (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 require further detailed evaluation.

Future Actions and Timeline

PacifiCorp will continue to evaluate energy storage for future resource and system needs. The Company is currently working on House Bill 2193 that directs electric utility companies in Oregon to procure one or more energy storage systems that have the capacity to store electrical energy.

Distribution Automation and Reliability

Distribution automation includes fault detection, isolation, and restoration (FDIR) and communicating faulted circuit indicators (CFCIs). FDIR utilizes strategically-placed, communication-enabled fault detection devices, distribution reclosers and motor-operated switches to automate restoration. These systems enable the utility to remotely or automatically reconfigure the distribution network in response to an outage. The devices communicate their status to a distribution management system (DMS), which determines the fault location and then sends out a signal to open or close fault isolation devices and switches to restore the maximum number of customers in areas outside the fault zone.

Project Description and Analysis

PacifiCorp has evaluated the reliability impacts and cost of distribution automation within the Oregon service area. While this technology would only be deployed on specific devices that can demonstrate significant improvements in reliability metrics, a holistic view of implementation is provided below to further the understanding of the overall system requirements. For the implementation of distribution automation the Company would begin by installing the devices at each existing switch and reclosing device in the state, of which there are approximately 36,000 locations. For a fully deployed system, at an estimated average cost $21,000 per location, a capital expenditure of $730 million would be required.

The Company estimates that the distribution automation would reduce sustained outage frequency to its Oregon customers by 8 % and outage duration by 6 %, improving reliability by an average of seven minutes per customer per year.

Using a cost per avoided customer minute metric, these improvements would result in a cost of $167 per customer minute interrupted, which is approximately 300 times more costly than the improvements the Company funds in its targeted reliability programs.

Communicating Faulted Circuit Indicators

No update since last report.

Future Actions and Timeline
PacifiCorp will continue to evaluate smart grid technologies for system reliability needs.

Distribution Management

Greater precision in operational data and minute-by-minute management is critical to long-term success as distribution systems become more sophisticated. A distribution management system 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, and real-time state estimation routines. These calculations and status levels reside on a foundation of network topology, device details, communications and more centralized and routinely maintained data than was historically part of the electrical network model.

When combined with an integrated volt/var optimization program that interacts with different types of substation and line equipment, the distribution management system can manage voltages to minimize line losses and energy needs while maintaining customer voltage quality in compliance with established standards. A distribution management system utilizes strategically placed equipment, including distribution transformers, distribution reclosers, motor-operated switches and fault detection devices as data sources for an electronic model that records and calculates key values integral to system operation. Such a holistic infrastructure enables remote operation of several lines and substation equipment potentially enhancing the efficiency of the distribution system. Operational efficiency can be gained as these integrated subsystems perform calculations, autonomously choose the appropriate actions, and then carry out those actions. For security, some designs require an effective extension of the utility's firewall to include the field intelligent electronic devices. In this configuration, the intelligent electronic devices then act as cyber security agents to detect and mitigate threats.

A distribution management system creates an intelligent distribution network model that provides ongoing data analysis from field-deployed intelligent electronic devices to maximize the efficiency and operability of the distribution network. A complete distribution management system provides distribution engineers with near real-time system performance data and highly granular historical performance metrics. This will support system planning, increases visibility of the system status and improves reliability metrics through better application and management of the distribution capital budgets.

With appropriate data inputs from field intelligent electronic devices, the distribution management system will be able to analyze the distribution network for both normal and emergency states and perform the following functions required for integrated volt/var optimization and fault detection, isolation, and restoration:

- 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 abnormal conditions and where possible, 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; and
- Suggest the switching sequence for line unloading should a condition arise where an operator needs to reduce the load on a specific device.

Outage Management

All electrical distribution systems are subject to faults caused by storms or 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 supervisory control and data acquisition (SCADA) systems, where available, and/or notifications to the Company’s customer service call centers. Since the vast majority of outages do not involve devices which have SCADA, customer notifications drive the understanding of minute-by-minute outage states. 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 conclusions as to where a fault may have occurred. To accelerate service restoration times, the integration of intelligent electronic devices 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.

Conservation Voltage Reduction Demonstration

Conservation voltage reduction (CVR) and integrated volt/var optimization (IVVO) can lower the voltage towards the minimum allowable voltage, which can reduce energy usage. However, a distribution system that is already maintained at a low voltage will see a negligible impact.

To better control the fall of system voltage over distance, intentional design and operation strategies such as the following can be employed:

1. Limit system losses via phase balancing, economically sized conductors, and the implementation of capacitors.
2. Dynamic but independent device control across all operating conditions, via line drop compensation, the use of switched capacitors, and the implementation of line regulators.
3. Dynamic and integrated (communicating) device control across all operating conditions

Generally the implementation costs climb from option 1 to 2 and from option 2 to 3 (IVVO). PacifiCorp has incorporated options 1 and 2 into its standard design and operating practices, and has found that the energy savings to be gained by implementing an integrated volt-VAR program are small and costly to obtain. These lessons were learned through the studies, pilot project, six-state circuit screening and intra-utility discussions and comparisons performed between 2010 and 2013. A more detailed account of these efforts is presented in previous editions of this report. Low existing voltage, low load density, and limited meter data at both the feeder and customer levels were all found to be important contributors to the Company's findings.

Future Actions

Throughout 2015, the Company is transitioning to a new, more powerful circuit analysis application called Cyme. This will allow better customer load modeling and time series analysis, and will help ensure that future planning efforts and project definitions are as accurate as possible.

Projects 3: Advanced Metering, Pricing and Demand Side Management

Advanced Metering

PacifiCorp has completed a comprehensive evaluation of AMI in the state of Oregon. The business case development and refinement was initiated in early 2014. PacifiCorp obtained information from leading industry vendors that described their business, what products they can deliver, which electric utilities have implemented their products, and benefits their customers have realized as a result of actual implementations. This data was insufficient to develop an accurate business case, so PacifiCorp initiated a formal request for proposal (RFP) aimed at further refining the business case. The request was issued on September 2, 2014, with a due date of October 15, 2014. Seven vendors responded. A status report was included in the 2014 annual Smart Grid Report. However, the final analysis of the RFP submissions had not been completed when the 2014 Smart Grid Report was filed.

In early 2015, the analysis of the proposals was refined, reviewed and completed. The final RFP review showed a marginally positive business case for AMI. This first indicator was encouraging and the Company began further analysis to ensure a complete review of all interdependencies.

During the review, it was recognized that key AMI functionalities, including dynamic pricing, demand response programs, and outage management, could not be gained without significant upgrades to the existing customer information system and other information technology (IT) applications. Several IT projects are either currently underway or are foreseen to be part of the AMI business plan. In addition, many of the benefits that are not quantifiable, such as reliability improvements, were not included in the business case as they can only be obtained with the correct IT projects in place and timed in a coordinated approach.

A comprehensive review to identify the specific order of implementation was initiated to understand the financial impacts associated with the number and level of projects and the associated resource requirements. Consideration was given to the specific order and timing of customer service projects, including AMI, and how they should be staged to leverage value for customers, resource availability and minimal impacts to customer service levels. Projections for new generation resources and project interdependencies were also included in the review.

The outcome of the review showed that key IT projects should be completed before implementing an AMI system. If implemented prior, the AMI system would only harvest benefits traditionally associated automated meter reading systems (drive-by meter reading). For illustration purposes only, the following diagram shows the relationship of the AMI business case, related IT and enabling projects and the AMI system deployment if started today. The timeline is feasible and logical when full consideration is given to interdependencies, delivered functionality, complexity and resource requirements.

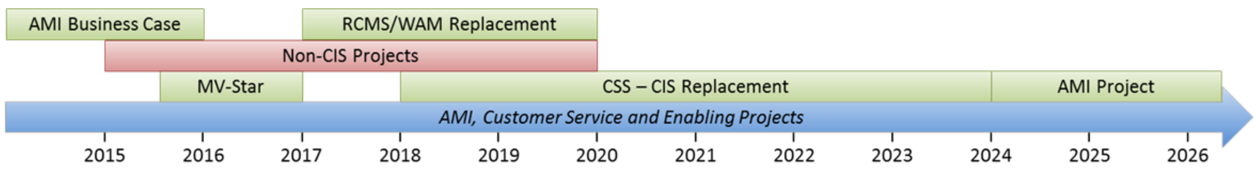

Figure 6 – AMI and Enabling Project Timeline

Each major project included in the illustration has several distinct projects that may be dependent on a prior project. For example, the MV-Star replacement project is dependent on the implementation of a meter data management system (MDMS). The MDMS was completed in 2014 and stabilization is ongoing. MV-Star would add the capability to harvest and store larger amounts of interval data. This capability can be leveraged by the AMI project. The scoping effort and project planning, along with a request for proposal will be completed in 2015 and the full implementation completed during 2016. The other major projects and their distinct projects are shown in Figure 7.

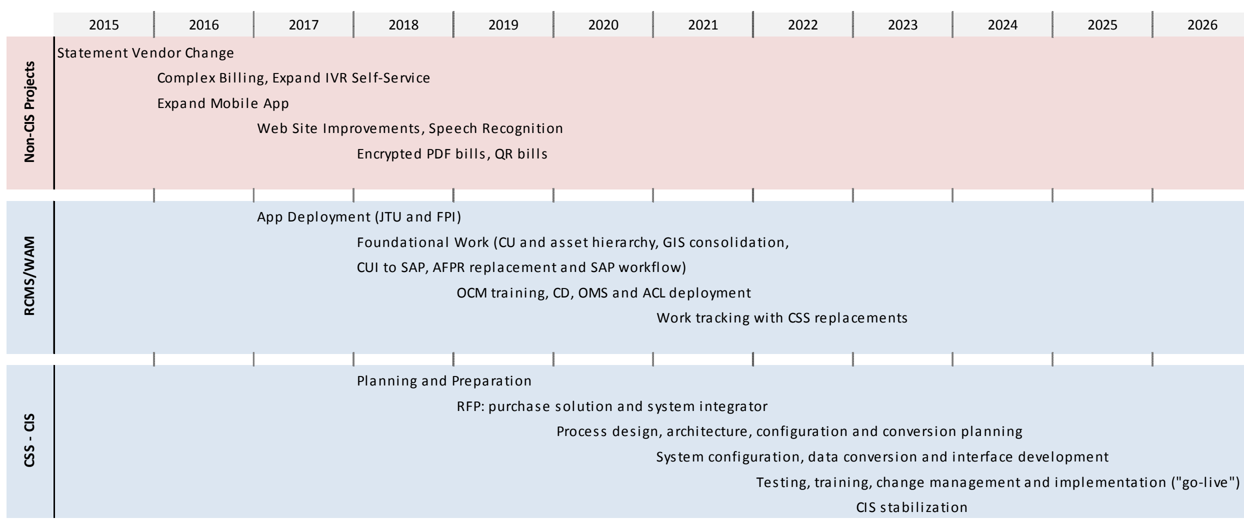

Figure 7 – Major Projects

In 2012, Pike Research estimated that 40% of customers would have smart meters by 2014. They forecasted this number to increase to 65% in 2020. During the review it was noted that at the end of 2014 the U.S. Energy Information Administration[8] estimated 43% of customers had smart meters. This aligns well with the Pike Research study. The presented timelines are in line with the industry, forecasted to utilize the resources in an efficient manner and will be continuously monitored to ensure maximum customer value is attained.

[8] U.S. Energy Information Administration Form EIA-826 "Monthly Electric Utility Sales and Revenue Report with State Distributions." http://www.eia.gov/electricity/data/eia826/

PacifiCorp will continue to evaluate automated and advanced metering systems to identify any changes in the technologies and additional costs or benefits that can be realized. Any identified changes may result in adjustments to the timeline shown above. Solutions are available that may provide a bridge to an AMI system and provide economic meter reading solutions for Pacific Power's rural-based customers and not adversely impact customer rates.

Customer Communications and Programs

No update since last report.

Demand Response

PacifiCorp's direct load control programs include Cool Keeper air conditioner (AC) load control and irrigation load control, which is categorized as Class 1 demand-side management under the PacifiCorp integrated resource plan. PacifiCorp also offers Class 3 demand-side management programs, which are time-of-use programs offered to specific customer classes. These demand-side management programs may have the potential to become more robust as better system communication and controls become available.

Demand response programs are used to reduce the peak load, when electricity is generally much more expensive. The PacifiCorp summer peak of 2014 was measured at 10,314 megawatts on July 14. System daily peaks for this time period are shown in Figure 8.

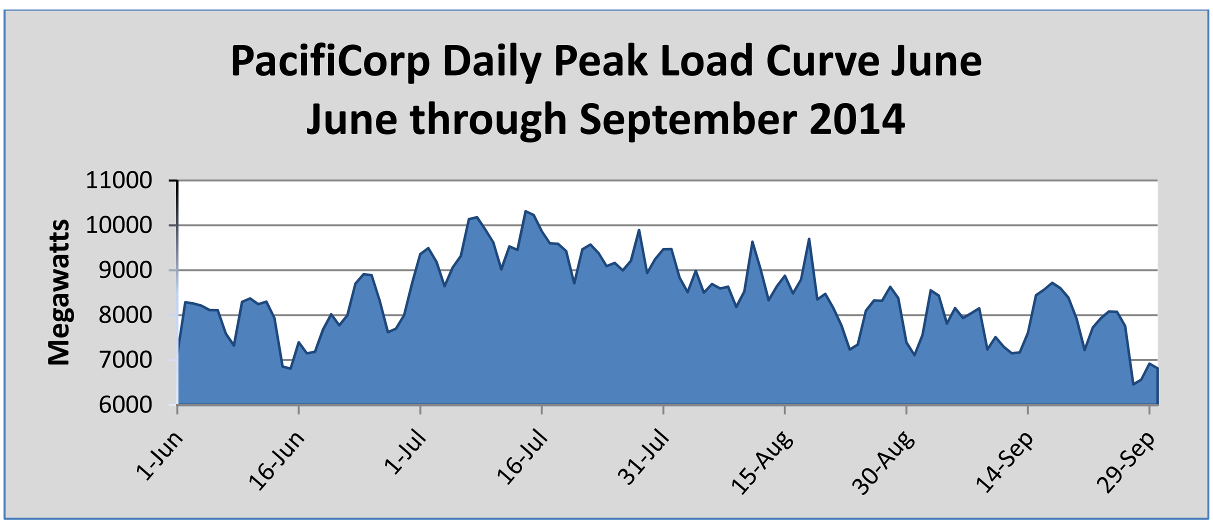

Figure 8 – PacifiCorp Daily Peak Load Curve

Home area network implementation is being explored along with advanced metering. A home area network may better enable customers and loads to participate in demand response by giving customers access to their real-time usage and by delivering pricing signals. However, while the advanced metering system may be used to transmit data to the customer, many utilities are finding that their advanced metering system does not have the bandwidth to incorporate additional applications, such as demand response programs. Increasingly, the trend for the transmission of information to the customer is not through the meter, but through other communication channels, such as the internet or application-specific networks.

The Public Utility Commission of Oregon has recommended "that a full financial analysis of direct load control demand response programs be included…, including not only the existing Cool Keeper program but also water heating, commercial cold storage, and other commercial and industrial applications." A financial analysis of direct load control demand response was conducted as part of the 2015 integrated resource plan with supporting analysis from "PacifiCorp Demand-side Resource Potential Assessment for 2015-2034 Volume 3[9] lists the Class 1 demand-side management levelized costs[10]. However, costs vary by region. For example, costs are lower in states such as Idaho and Utah with substantial irrigation potential. Achieving savings through Irrigation Load Control in California, Oregon, and Wyoming is likely to be more difficult due to crop patterns, shorter irrigation seasons and smaller pump sizes.

Table 3 – Class 1 DSM Levelized Costs for Utah ($/kW-year)

	Direct Load Control	Curtailable Agreements	Irrigation Load Control
Rocky Mountain Power	Cost ($/kW-year)	Cost ($/kW-year)	Cost ($/kW-year)
Utah	$62	$77	$52

PacifiCorp's 2015 integrated resource plan modeling results did not select new direct load control demand response until 2022 in the preferred portfolio.[11] This indicates that Utah direct load control demand response is not a least-cost resource until that date or later.

In its integrated resource plan, PacifiCorp implements least-cost, least-risk planning principles to arrive at a preferred resource portfolio and associated action plan. The preferred portfolio selection process begins by developing resource portfolio alternatives using System Optimizer. System Optimizer selects from a broad range of resource alternatives, including direct load control (i.e., Class 1 DSM), taking into consideration the cost, performance, size, and location of each resource alternative and taking into consideration how each resource alternative would affect costs when added to PacifiCorp's integrated system. The cost to acquire or build a resource is only one factor that influences the selection of a given resource type in least cost resource planning. PacifiCorp's 2015 integrated resource plan preferred portfolio does not include either

[9] Applied Energy Group, PacifiCorp Demand-side Resource Potential Assessment for 2015-2034. [Online] Available:http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSM_Potential_Vol_3_Class_13_Report_FINAL_Jan30-2015.pdf
[10] Table 4-6, page 4-6 of 2015 potential assessment.
[11] PacifiCorp, *2015 Integrated Resource Plan Volume I* [Online]. Page 196. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf

new direct load control or simple cycle combustion turbine plants until 2022 of the planning horizon.

With a reduced load forecast in the 2015 integrated resource plan as compared to the 2013integrated resource plan, Class 1 demand-side management resources did not surface in the 2015 integrated resource plan preferred portfolio, until 2022. Through the front seven years of the integrated resource plan 20-year planning horizon, PacifiCorp's least-cost, least-risk preferred portfolio is comprised of Class 2 demand-side management resources (energy efficiency) and front office transactions, which are representative of short-term firm forward market purchases. The cost of these resource alternatives (Class 2 demand-side management and front office transactions), net of the system benefits that these resources provide in PacifiCorp's system, are simply lower-cost alternatives than acquiring direct load control resources, given current projections of resource need, through at least the first seven years of the planning horizon. Given that Class 2 demand-side management and front office transactions are lower-cost alternatives to direct load control, using direct load control to offset firm forward market purchases would only increase portfolio costs.

PacifiCorp included in its 2015 integrated resource plan a flexible resource needs assessment.[12] This analysis identifies the need for flexible resources over the 20-year integrated resource planning horizon and subsequently assesses this need in relation to supply. The analysis clearly demonstrates that PacifiCorp has sufficient flexible resources to serve its needs through the planning horizon. Moreover, PacifiCorp's integrated resource plan modeling framework accommodates the flexible operating characteristics of resources when resource portfolios are analyzed in the Planning and Risk (PaR) model. PaR studies are performed in each integrated resource plan to analyze the relative stochastic risk among portfolios, which influences the selection of the least-cost, least-risk preferred portfolio. Inasmuch as portfolios include direct load control programs that can offer operating reserve capabilities, the operating reserve benefits for those resources are captured in the PaR results.

Other potential system benefits of demand response, such as "programs that increase specific loads during periods of high wind generation and low overall load" are not specifically considered; however, the identification of resources and reserves through integrated resource planning addresses this need.

[12] PacifiCorp, *2015 Integrated Resource Plan Volume II, Appendices* [Online]. Page 87. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

Time-based Pricing

Project Summary
PacifiCorp has existing time-of-use rates for specific customer classes within each state.

Project Description
Time-based pricing can encourage customers to change energy usage patterns. The most common price signals in the industry today are time-of-use, critical peak pricing and critical peak rebate programs.[13] A combination of time-of-use and critical peak pricing, or time-of-use and critical peak rebate pricing programs, are the most prevalent and, if designed and implemented appropriately, can present opportunities for creating reductions in energy usage during critical periods when system peaks are present.

A two year pilot program in Oregon was placed in-service beginning with the 2014 irrigation season and implemented on-peak energy surcharges and off-peak energy credits. A report on the pilot was filed with the OPUC in December 2014. The report can be viewed at http://www.pacificorp.com/es/irp/irpsupport.html.

[13] U.S. Department of Energy. *Time-Based Rate Programs* [Online]. Available: http://www.smartgrid.gov/recovery_act/deployment_status/time_based_rate_programs

Table 4 is an updated summary of PacifiCorp's price schedules by state and shows current levels of participation in voluntary program**.**

Table 4 – Summary of Price Schedules by State

Description	State	Schedule	Participating Customers (Dec. 31, 2014)	Eligible Customers	Participating Eligible Customers	Voluntary or Mandatory
Residential TOU Pricing	Utah	2	414	737,060	0.06%	Voluntary
	Oregon	4/210	1,169	481,744	0.24%	Voluntary
	Idaho	36	13,230	59,633	22.19%	Voluntary
General Service (*Business Sector and Irrigation*) TOU Pricing, Either Energy or Demand	Washington	47T	1	1	100%	Mandatory
	Washington	48T	67	67	100%	Mandatory
	California	AT48	17	17	100%	Mandatory
	Idaho	35/35A	3	10,283	0.03%	Voluntary
	Wyoming	33	10	10	100%	Mandatory
	Wyoming	46	81	81	100%	Mandatory
	Wyoming	48T	28	28	100%	Mandatory
	Utah	6A/6B	2,394	97,279	2.46%	Voluntary
	Utah	8	253	253	100%	Mandatory
	Utah	9/9A	160	160	100%	Mandatory
	Utah	10	246	3,063	8.03%	Voluntary
	Utah	31	7	7	100%	Mandatory
	Oregon	23/210	262	76,166	0.34%	Voluntary
	Oregon	41/210	59	5,510	1.18%	Voluntary
	Oregon	41/215	6	50	12.00%	Voluntary (Pilot)
	Oregon	47	7	7	100%	Mandatory
	Oregon	48	197	197	100%	Mandatory

Cool Keeper AC Direct Load Control

Project Summary

PacifiCorp has an existing direct load control demand response program, known as Cool Keeper, in Utah.

Project Description and Analysis

PacifiCorp continues the Cool Keeper program in an effort to manage summer peaks in the Wasatch Front area. Residential and small commercial customers participate in the program, which allows the Company to manage air conditioning loads. Customers are provided with credit on their bills for their participation. The Cool Keeper program directly controls customers' air conditioners with a radio-enabled device that cycles the compressors off and on. With the current number of Cool Keeper load controls installed the Company has control of up to 110 megawatts of power during critical peak events.

Future Actions and Timeline

Research indicates that over the next 20-year period a total potential of 189 megawatts may be available in the Rocky Mountain Power territory and 37 megawatts may be available in the Pacific Power territory.[14] For the 2014 summer season, PacifiCorp upgraded the existing Cool Keeper system to improve the remote devices and enable measurement and verification of savings during events. This upgrade is expected to further increase the overall efficiency of the direct load control system through the use of a two-way communication network.

Irrigation Load Control

Project Summary

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.

Project Description

Starting in 2013, PacifiCorp selected EnerNOC to manage a ten year irrigation load control program through a pay for performance agreement. EnerNOC's responsibilities include enrollment, equipment installation, dispatch management, performance calculations, and customer service. Importantly, under this construct PacifiCorp only pays for capacity available during program hours, as measured by EnerNOC's energy monitoring technology and adjusted through a performance factor to account for those sites which opt not to participate during specific dispatch events. In order to achieve this incentive structure, interval metering was necessary. EnerNOC's equipment solution provides 55-minute interval energy monitoring as well as remote irrigation equipment control. EnerNOC's web-based portal provides irrigators and PacifiCorp with near real-time energy usage data.

The irrigation load control program is currently available to Tariff Schedule 10 customer sites in the Rocky Mountain Power Idaho and Utah service territories. Participating sites are compensated for shutting off irrigation load for specific time periods determined by Rocky Mountain Power, and are provided day-ahead notice of dispatch events. Customers always have the opportunity to opt out of (i.e., choose not to reduce load) for dispatch events as necessary for their operations. Customer incentives are based on a site's average available load during load control program hours adjusted for the number of opt outs or non-participation. The program hours are 12 to 8pm Mountain Time, Monday through Friday, and do not include holidays.

[14] Applied Energy Group (January 2015) PacifiCorp Demand-side Resource Potential Assessment for 2015-2034, Volume 3 [Online] Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSM_Potential_Vol_3_Class_13_Report_FINAL_Jan30-2015.pdf page 4-3

The 2014 program season ran from Monday, June 9 through Friday, August 15. Average weekly available load reduction as monitored through EnerNOC's equipment was 134.2 megawatts. There were four irrigation load control events, each four hours in length.

Future Actions

The agreement with EnerNoc is for 10 years. The individual curtailments are expected to range from 65-260 megawatts depending on participation, weather and crop conditions.

A seven megawatt pilot program is under consideration for California and Oregon. The Company's 2015 Integrated Resource Plan has selected capacity resources from irrigation load management in Oregon and California beginning in 2022, the Company is evaluating the feasibility of offering a pilot program to investigate whether its current program design and approach operating in Utah and Idaho will be effective. The Company will also assess whether the Pilot Program can be delivered at the price assumed in the Company's resource plan. If determined feasible, implementing a Pilot Program for the 2016-2020 irrigation seasons will provide the Company and its irrigation customers the time needed to work through barriers and implement a permanent program in 2021 in time for the 2022 resource need.

Projects 4: Distributed Resource and Renewable Resource Enhancements

These are projects related to renewable resources and distributed generation, including customer generation.

Distributed and Renewable Resources

Project Summary

PacifiCorp has significant distributed and renewable resource capacity. Renewable and non-carbon resources consist of over 25% of PacifiCorp's owned resources; other resource portfolio details are listed below.

Project Description

The upcoming 2015 integrated resource plan will provide a summary of the distributed resource level expected to be integrated into the PacifiCorp portfolio. The "Distributed Generation Resource Assessment for Long-Term Planning Study,"[15] which will be included as an appendix in the 2015 integrated resource plan, was developed "to project the level of distributed resources [that] customers might install." Key findings include state-by-state technical resource potential and market projections, suggesting a base case of approximately 25 megawatts of distributed generation in PacifiCorp's Utah service area by 2020.

PacifiCorp has an "additional 417 [megawatts] of wind projects since the 2012 [wind integration study]." This includes "222 [megawatts] of new wind projects that came online in 2012 in PacifiCorp's east balancing authority", and "195 [megawatts] of existing wind projects (Goodnoe Hills and Leaning Juniper) that were electrically moved from Bonneville Power Administration's balancing authority area to PacifiCorp's west balancing authority area."[16] The 2013 integrated resource plan included an action item to update the wind integration study for the 2015 integrated resource plan, which is ongoing.

PacifiCorp has over 1,800 megawatts of owned and purchased wind resources, which includes over 1,000 megawatts of owned wind resources. Over 20% of PacifiCorp's owned generating capability is made of wind, hydro, geothermal, and other non-carbon resources. These resources account for about 17% of PacifiCorp's total energy output.[17] PacifiCorp owns the 2-megawatt Black Cap solar resource in Oregon, and the 34-megawatt Blundell geothermal resource in Utah.[18] Through 2014, PacifiCorp's customers have installed over 21,000 kilowatts of solar

[15] Navigant, Inc. *Distributed Generation Resources Assessment for Long-Term Planning Study* [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf

[16] *2015 Integrated Resource Plan Public Input Meeting 3*, August 7-8, 2014 [Online]. Page 71. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP_PIM03_8-7-8-2014.pdf

[17] *Our Wind Energy Resources* brochure [Online]. Available: http://www.pacificorp.com/content/dam/pacificorp/doc/Efficiency_Environment/PC_WindEnergyHandout.pdf

[18] PacifiCorp's Renewable Resources [Online]. Available: http://www.pacificorp.com/es/re.html

energy through our incentive program; customers have installed an additional 2,600 kilowatts through the Energy Trust of Oregon's solar incentives in 2014.

Smart Inverters

The Company has been actively involved in the Institute of Electrical and Electronics Engineers 1547 standard for interconnecting distributed resources with electric power systems. The group is currently investigating ways to adopt prudent smart inverter functionalities as standard features that would enable higher penetrations of distributed generation on U.S. utility networks. Recently, the California Public Utility Commission decided to adopt modifications to Electric Tariff Rule 21[19] to capture the technological advances by smart inverter. The autonomous functionalities of smart inverters include, but are not limited to, the following:

- Anti-islanding protection
- Low and High voltage ride-through
- Low and High frequency ride-through
- Dynamic volt-var operation
- Ramp rates
- Fixed power factor
- Soft start reconnection

The above-mentioned functionalities are paramount to accommodate large-scale integration of renewables on the transmission and distribution system without adversely affecting the effective and efficient operation of PacifiCorp's electrical grid.

PacifiCorp is currently in the final stages of updating its interconnection policy for distribution systems to ensure the standards are well-aligned with the latest industry standards. However, mandating some of the smart inverter functionalities may not be prudent at this time considering the inverter manufacturers are still in the process of developing and certifying the new technology. Underwriters Laboratories is currently reviewing the smart inverter specifications and will subsequently revise the UL 1741 *Safety testing of inverters including anti-islanding requirement* standard. Implementation of these advanced functionalities is in the best interest of

[19] *Rule 21 is in place for PG&E, SCE, SDG&E and BVES. Sierra also has a version of Rule 21 but without the same timeframe provision. <u>We require PacifiCorp, Sierra and MU to follow the same principles of timely review and disposition of interconnection requests as in Rule 21 for other utilities. We do this without requiring that they file either their own version of Rule 21, amend then current rules, or file another interconnection protocol.</u> We will enforce the requirement of timely review and disposition of an interconnection request, however, if a complaint is brought to our attention* . D.07-07-027 Pages 41-42.

PacifiCorp and will enforce some of these requirements as soon as pertinent standards are approved.

Electric Vehicles

Plug-in electric vehicles are expected to become more widespread as electric vehicle and battery technologies advance and electric vehicle 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 and vehicle-to-building 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.

PacifiCorp has observed a slow growth of electric vehicles being interconnected in only a couple areas of its service territory. With the current penetration levels of electric vehicles on the grid the Company is not concerned with adverse impacts of the added load on the local distribution network.

To ensure that these vehicles do not adversely impact the distribution system, 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.

PacifiCorp began studying the effects of widespread electric vehicle penetration in 2010 by tracking electric vehicle 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 results of this study 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 electric vehicles having limited negative impact on the Company's electric grid. The Company continues to work with Clean Cities Coalitions and other entities within the service territory to facilitate public charging infrastructure development, discussions and opportunities. Additionally, the Company is making an effort to analyze different rate structures that can incentivize electric vehicle owners thereby increasing adoption rates.

The Energy Information Administration has been consistently making downward adjustments to their electric vehicle sales growth forecasts to reflect slow economic growth. For instance, in

2007 the Energy Information Administration forecast[20] suggests sales of hybrid vehicles to be about 1.4 million units sold in 2020; in 2014, that figure was revised to 510,000[21], a downgrade of over 60%. This downgrade is consistent for forecasts out to 2030 and indicates that the Energy Information Administration analysts are predicting a cooling of the electric vehicle market. This cooling trend may change if the national economy picks up, petroleum prices continue to rise or battery technologies continue to improve.

Vehicle-to-Grid Technology

Vehicle-to-grid technology may offer quick-response, high-value electric services to balance load. Research institutions, including the University of Delaware[22] and a consortium[23] of IBM, DTU-CET and Risoe, have demonstrated the concept. While the concept has been proven, there are many issues to overcome before adoption in power system operations and markets. In addition, vehicle-to-grid is not a necessary system in order to leverage electric vehicles for demand response services. Demand response functionality is not limited by the inverter or battery charging concerns.

Commercial availability of electric vehicle supply equipment and batteries robust enough to implement vehicle-to-grid technology remains scarce, even though there is a rationale and economic motivation for widespread implementation. When battery costs come down enough, energy prices increase enough or technologies arise that allow electric vehicle owners to use their cars for arbitrage or emergency backup without fear of voiding warranties or the prospect of a dead car battery before their morning commute, only then will vehicle-to-grid become a viable widespread demand and frequency response tool.

The Electrification Coalition points out some of the main issues with vehicle-to-grid technology[24]:

- Applications are unlikely to appear before third or fourth generation electric vehicles evolve
- Vehicle-to-grid technology requires bidirectional chargers, which are more expensive than traditional chargers

[20] U.S. Energy Information Administration. (2007). *Annual Energy Outlook* [Online]. Figure 52, p. 81. Available: http://www.eia.gov/forecasts/archive/aeo07/,
[21] U.S. Energy Information Administration. (2007). *Annual Energy Outlook* [Online]. Figure MT-27, p. MT-15. Available: www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf,
[22] University of Delaware. *The Grid-Integrated Vehicle with Vehicle to Grid Technology* [Online]. Available: http://www.udel.edu/V2G/
[23] Danski Energi. *The Edison Project* [Online]. Available: http://www.edison-net.dk/
[24] Electrification Coalition. (2009). *Electrification Roadmap* [Online]. Section 2.4.5, Vehicle to Home and Grid. Available: http://www.electrificationcoalition.org/policy/electrification-roadmap,”

- 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 electric vehicle 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 and electric car manufacturers, 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.

Microgrids

A microgrid is a localized grouping of distributed energy resources (DERs), which can operate both in parallel with the larger distribution system and as a self-supplying island. The DERs may be any type of local generation or demand-side resource, such as natural gas, diesel, fuel cell, biofuels, solar PV, wind, battery, and demand response. While these resources may provide ancillary benefits, the fundamental purpose of a microgrid is to provide high reliability electricity for the local grid. Microgrids can be implemented on the scale of the distribution feeder, a business or university campus, or a building.

Historically, microgrids have been installed for remote communities (e.g., Alaska), while modern microgrids are generally installed on business, university, military, and government campuses. Including both groups, there have been over 100 microgrids installed since 1990[25]. Remote communities may require microgrids due to high energy costs and low electric reliability. Businesses and universities apply microgrids to high-density campuses that have critical operation loads. Historical, remote installations have typically combined renewable generation with diesel generators, while some modern installations may include batteries, which are a faster-acting resource. Distribution-level microgrids could also support disaster-prone regions. However, the high cost of microgrid assets make them impractical for typical distribution utility customers, particularly those in low-density or rural areas[26].

Some examples of microgrids are the Oregon State University (OSU) Energy Center, Portland General Electric's (PGE's) Salem Smart Power Center, the Camp Williams facility, an eBay data center, and the University of California, San Diego campus.

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[25] ABB, "Worldwide microgrid projects (2012)", Internet: http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/d442ac1a4d0a1cd0c1257afd005443ad/$file/Renewable%20integration%20global%20reference%20list_EN.pdf, 4/7/14.

[26] Robert Liam Dohn, "The business case for microgrids; White paper: The new face of energy modernization", Siemens.

The OSU Energy Center, which began operation in 2010, is a 6.5 MW cogeneration facility that supplies half of OSU's electrical needs onsite. The facility includes a natural gas-fired turbine, heat recovery steam generator, and diesel backup. The $55,000,000 facility was built to replace a retiring heat plant and provide energy cost savings for OSU, but it can also be used as a microgrid. The Energy Center has enabled a portion of the campus to remain powered during local distribution system outages.

Portland General Electric's (PGE) Salem Smart Power Center, which is part of the Pacific Northwest Smart Grid Demonstration Project, is designed to enable a distribution feeder microgrid. Neither remote nor a high-density business campus, the center demonstrates the application of a microgrid to an atypical set of customers. The system combines an existing 616-panel commercial rooftop solar installation and 5.7 MW of PGE's dispatchable standby generation system (diesel) with a 5 MW, 1.26 MWh Li-Ion battery system. The system provides highly reliable power to the 500 local customers on the feeder, which has a typical load of 2.5 MW. The $25,000,000 system was funded in part by PGE ($6.5M) and the DOE ($10M), and leverages PGE's existing dispatchable standby generation system and existing customer solar generation.

Camp Williams augmented an existing wind generation facility, consisting of one 660-kW and one 225-kW wind turbine, with a diesel generator and a load control scheme in 2013. At a cost of $795,000 this gives the Utah Army National Guard base the capability to operate the facility when local utility power is interrupted.

An eBay data center in Salt Lake City with an 8 MW load has the capability to source 6 MW from five banks of Bloom Energy fuel cell servers. These fuel cell servers use natural gas as a fuel source. While eBay plans to source the remaining 2 MW from Ormat Energy Converter generation, this will not be onsite. During a utility-caused outage situation, an intelligent load shedding scheme coupled with available generation, eBay can potentially operate as a microgrid.

The University of California, San Diego microgrid, one of the largest worldwide, generates 92% of the annual electricity used on campus, serving the campus population of over 45,000 students, faculty, and staff. The microgrid combines a 2.8 MW fuel cell, utilizing methane gas from the campus wastewater treatment plant, 2.3 MW of solar PV, and a 30 MW natural gas-fired combined heat and power (CHP) plant. A water chiller, charged at night, can be used to cool buildings during the day. UCSD is also "currently using or testing several different types of battery/chemical storage systems, an ultracapacitor-based system and a thermal energy storage system".[27]

[27] Triton (UCSD), "Microgrid: Keeping the Lights On", http://alumni.ucsd.edu/s/1170/emag/emag-interior-2-col.aspx?sid=1170&gid=1&pgid=4665, 4/7/14.

Conclusion

Presently the economics to implement a comprehensive smart grid system throughout PacifiCorp are cost prohibitive. The business case indicates that an overarching smart grid vision will not benefit our customers. Smart technologies can benefit specific issues, such as the implementation of a meter data management system for the emerging energy imbalance market, dynamic line rating for specific constraint transmission pathways, and direct load control to manage seasonal peaks in the Wasatch Front area, where direct load control is more economical and peaks are more costly. PacifiCorp will continue to monitor smart grid activities throughout the nation as more pilots and programs are implemented.

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 for each will be given in the appropriate section, if necessary.

Abbreviation	Name
AC	Air Conditioning
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
AMS	Advanced Metering System
CAIDI	Customer Average Interruption Duration Index
CES	Centralized Energy Storage
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DLC	Direct Load Control
DLR	Dynamic Line Rating
DMS	Distribution Management System
DSM	Demand-Side Management
DR	Demand Response
FDIR	Fault Detection, Isolation, and Restoration
IVVO	Integrated Volt/VAr Optimization
kW	Kilowatt
MW	Megawatt
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
TOU	Time of Use
TSP	Transmission Synchrophasor
WECC	Western Electricity Coordinating Council

Appendix B - Smart Grid Technologies at Other Companies

- Portland General Electric (PGE) is partnering with state and local government, higher education and businesses to help expand the electric vehicle infrastructure in Oregon and find ways electric vehicle owners can benefit from smart grid technology in the future. https://www.portlandgeneral.com/our_company/energy_strategy/smart_grid/initiatives.aspx