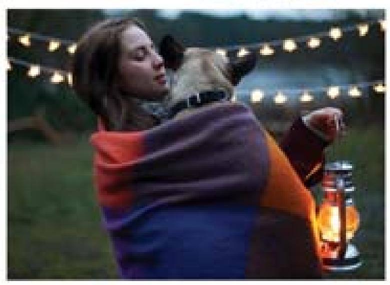
PacifiCorp Smart Grid
Biennial Report – Oregon




August 1, 2019

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List of Acronyms

AC ....Air Conditioning
AMI..Advanced Metering Infrastructure
AMM..Advanced Metering Management
AMR ....Automated Meter Reading
AOC ....AMI Operations Center
BES ....Bulk Electric System
CAES ....Compressed Air Energy Storage
CES ....Centralized Energy Storage
CFCI...Communicating Faulted Circuit Indicators
CGR ....Connected Grid Router
CIS ....Customer Information System
DA ....Distribution Automation
DER..Distributed Energy Resource
DDR ....Dynamic Disturbance Recorder
DFR..Digital Fault Recording
DLC..Direct Load Control
DLR..Dynamic Line Rating
DMS ....Distribution Management System
DSM ....Demand-Side Management
DR ....Demand Response
EIM ....Energy Imbalance Market
EMS..Energy Management System
EPC..Engineer, Procure and Construct
ESS...Energy Storage Systems
ETR..Estimated Time of Restoration
EV ....Electric Vehicle
EVSE..Electric Vehicle Supply Equipment
FAN..Field Area Network
FDIR ....Fault Detection, Isolation and Restoration
FLISR...Fault Location, Isolation and Service Restoration
FR...Fault Recording
IEEE...Institute of Electrical and Electronics Engineers
IRP ....Integrated Resource Plan
ISO ....Independent System Operator
IT..Information Technology
IVVO..Integrated Volt/VAR Optimization
kW..Kilowatt

kWh..Kilowatt-hour
M&V ....Measurement and Verification
MDMS ....Meter Data Management System
MW ....Megawatt
MWh ....Megawatt-hour
NERC ....North American Electric Reliability Corporation
NIST...National Institute of Standards and Technology
NREL ....National Renewable Energy Laboratory
O&M ....Operations and Maintenance
OMS ....Outage Management System
PDC..Phasor Data Concentrator
PHES..Pumped Hydroelectric Energy Storage
PMU ....Phasor Measurement Unit
RAS..Remedial Action Scheme
RBM...Regional Business Manager
RE ....Range Extender
RTU..Remote Terminal Unit
SER ....Sequence of Events Recording
SCADA ....Supervisory Control and Data Acquisition
SOC2..Service Organization Controls
TOU ....Time-of-Use
UL ....Underwriters Laboratories
WECC ....Western Electricity Coordinating Council

I. Executive Summary

This 2019 Smart Grid Report (Smart Grid Report or Report) provides PacifiCorp's biennial update on grid modernization, smart grid initiatives, and projects in response to the Public Utility Commission of Oregon's (Commission's) Order No. 12-158 and Order No. 17-290 in Docket UM 1460, as well as Order No. 18-045 in Docket UM 1667.

Grid modernization is the application of advanced technology, communications, and controls to the power system, from generation, through transmission, and distribution to the customer. This Smart Grid Report focuses on technologies and processes that can be readily integrated within the existing electrical grid infrastructure.

While "grid modernization" projects may not fall explicitly within the context of the Smart Grid Report, such projects or initiatives are considered essential to realizing a strong and robust smart grid. For this reason, PacifiCorp d/b/a Pacific Power (Pacific Power or PacifiCorp) continues to focus on effective enhancements to form an affordable and proven foundation for existing and future smart grid projects.

The deployment of Advanced Metering Infrastructure (AMI) has been a key effort at the PacifiCorp the past several years, consistent with the AMI roadmap outlined in 2017. In 2019 the company will complete AMI deployment in the state of Oregon, and leveraging that technology is one of the core elements in its advanced technology deployment.

Additional key PacifiCorp efforts that are intended to provide benefits within the state of Oregon include:

- Developing tools which allow the customer or the company to leverage data that result from PacifiCorp's AMI deployment;
- Participating in the Energy Imbalance Market (EIM);
- Application of PacifiCorp's "Non-wires" facilities assessments, i.e. the process which supports consideration of distributed energy resources (DER) as a proxy for legacy "wires" system reinforcement projects;
- Deployment of distribution field area networks (FAN) to enhance intelligent electric devices (IED) siting;
- Distribution automation (DA) pilot projects;
- Installation of real-time monitoring equipment for the Portland Secondary Network; and
- Installing transmission synchrophasor locations, as well as modeling criteria consistent with MOD-033-1 and PRC-002-2.[1]

[1] Expand MOD and PRC drop down menus at: https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States.

PacifiCorp's investments in grid modernization and smart grid technologies are explored in this Report. PacifiCorp has completed, is monitoring, or is developing grid enhancement initiatives that include:

- **Advanced Metering Infrastructure** – network and metering infrastructure that improves customer service and provides a platform for future smart grid applications
- **Transmission Enhancements** – transmission system investments that improve grid reliability and monitoring
- **Substation Enhancement** – substation investments that increase the flexibility of distributed energy resource integration
- **Distribution Field Communication** – initiatives to deploy field area network to support AMI, DA, CYME modeling, and information exchange
- **Distribution Automation** – DA investments in hardware and software that enable remote or automatic configuration of the distribution network
- **Demand Response** – non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating parties.[2]
- **Distribution Network Enhancements** – distribution system investments in technologies that improve targeted system efficiency through demand side management, host centralized renewable integration and expand distributed energy resource programs.

As part of the company's commitments to provide safe, reliable and cost effective service to its customers, it continues this smart grid journey, as outlined within this document.

[2] https://www.nwcouncil.org/energy/energy-advisory-committees/demand-response-advisory-committee.

II. Staff's Recommendations for the 2019 Smart Grid Report

In response to PacifiCorp's 2017 Smart Grid Report, the Commission adopted Commission staff's recommendations for the 2019 Smart Grid Report in Order No. 18-045. Table 1 provides staff's recommendations alongside the page numbers where the recommendation is incorporated. A high-level summary of informal comments and company responses is included in Appendix F.

Table 1 - Summary of Order No. 18-045 Recommendations

Recommendation Description	Page
1. PacifiCorp should continue to include a high-level table summary of all stakeholder informal comments and corresponding Company responses as an appendix in future smart grid reports.	Appendix F
2. PacifiCorp should continue to update the AMI Roadmap using the stated tracking methods. The Company should also specify a method for tracking customer engagement. The Company should also develop a system by the next Smart Grid report to perform and report on the Impacts of financial modeling on AMI action prioritization and solution comparison among different applications.	9-15, 31-33, Appendix C
3. The Company should provide updates and results of its expanded PMU installation project and provide additional information in future smart grid reports on the evaluation process used by the company in choosing deployment locations for the synchrophasors that will provide the data critical for compliance.	16-18
4. The Company should provide results from its 2017 RFP for load control services, and what projects, if any, were installed. The Company should provide its assessment of the pilot in regards to the future of the load control program.	42-44
5. PacifiCorp should update their progress of linking distributed devices to its OMS, EMS, DMS, and each other, if applicable, in its 2019 Smart Grid Report. The Company should also provide an overview of its adherence to the IEC 61968 standard.	26-27
6. PacifiCorp should provide an update on any field area network or communication functionality implementation.	27-30
7. PacifiCorp should continue to keep the Commission apprised of demand response developments in future smart grid reports and should track and update in its next report the market development for DR technology, customer demand for DR products and services, and assess the impact of DR on Smart Grid initiatives, including but not limited to renewables integration.	41-43
8. PacifiCorp should summarize any projects screened using the DER tool where DER projects were found to be a cost effective alternative to traditional solutions, and describe any DER projects that were or will be installed due to positive results. In addition, the Company should share in its next report the evaluation of the eight separate values found in the Utility Applications and Value streams, how those values may stack, and more information on the modeling the Company is using to value energy storage and any impacts from this modeling on project evaluation.	46-47
9. PacifiCorp should summarize its findings of its smart inverter analysis project, and what projects or infrastructure involving smart inverters, if any, have been initialized.	48-50

10. The Company should provide detail of the distribution automation project in the Lincoln City area and any other deployments, as well as any results observed from project deployment.	34-38
11. The Company should provide an update and results of the Portland network monitoring system installation, as well as plans for future deployment.	38-39

III. Smart Grid Strategies, Objectives and Goals

The purpose of the Smart Grid Report is to detail the philosophy and scope for PacifiCorp to deliver, develop, and outline the strategies, objectives, and goals that are part of the company's smart grid road map. PacifiCorp's road map will align the relative start dates of various components to convey the progress required to reach greater smart grid deployment. The starting date and schedule of progression of any effort must be driven by the fundamental economics laid out in a financial analysis designed to protect customers' best interests.

A. Strategies

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

- Ensure that smart grid investments provide service at a reasonable cost by comparing products and solutions using a financial model highlighting 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;
- Leverage broad resources at PacifiCorp's disposal, including lessons learned through existing analysis and work from Berkshire Hathaway Energy cross-business initiatives; and
- Increase customer awareness and understanding of how the electric system works and how energy usage impacts and drives company investments and operations.

B. Objectives

PacifiCorp identified the following short-term objectives as part of the company's smart grid efforts:

- Provide customers with tools and understanding that will better enable them to make beneficial changes to their energy usage;
- Continually improve the customer experience through valued customer communications; and
- Optimize PacifiCorp's electric system through the implementation of cost-effective smart grid technologies.

C. Goals

By implementing the objectives mentioned above, PacifiCorp is on track to achieve the following smart grid goals:

- Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution network;
- Enhance customer service and minimize the cost of utility operation;

- Enhance customer ability to save energy and reduce peak demand; and
- Enhance the ability to develop renewable resources and distributed generation.

PacifiCorp seeks to utilize smart grid technologies to optimize 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. PacifiCorp will meet these goals by utilizing strategies that analyze the total cost of ownership, performing well-researched cost-benefit analyses and focusing on customer outreach. In opening docket UM 2005, which included a whitepaper titled "A Proposal for Electric Distribution System Planning"[3], the Commission outlined a list of its proceedings with broad categories of the niche that proceeding fulfilled, reframed below, in Figure 1.

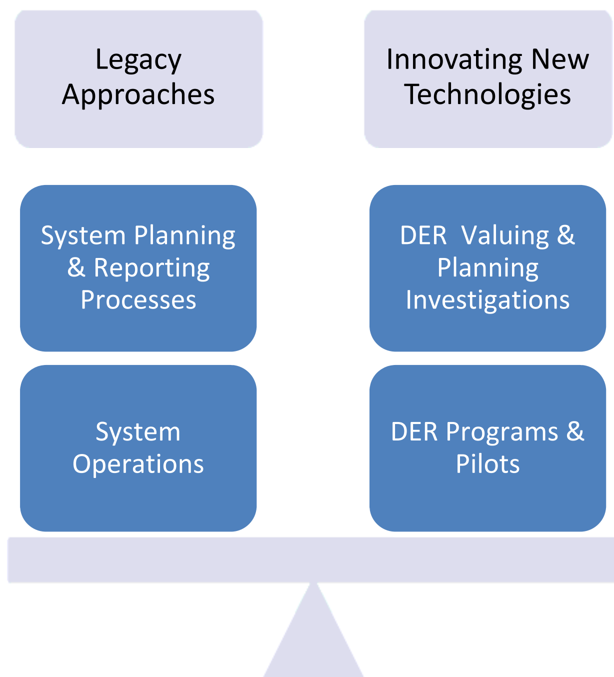


Figure 1 – Commission Proceedings

[3] https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.

IV. Projects Overview

PacifiCorp has implemented a number of grid modernization and smart grid-related projects and programs. Section V describes the individual projects, programs and efforts in detail. Figure 2 shows projects included in the 2019 Report as well as projects included in prior-year reports. These projects are chosen based on analysis of their ability to cost-effectively improve service to customers. These projects can apply to any sector of the power system, which support the smart grid concepts as depicted in Figure 3. The full benefit of many smart grid applications are dependent upon full deployment of preceding technologies.

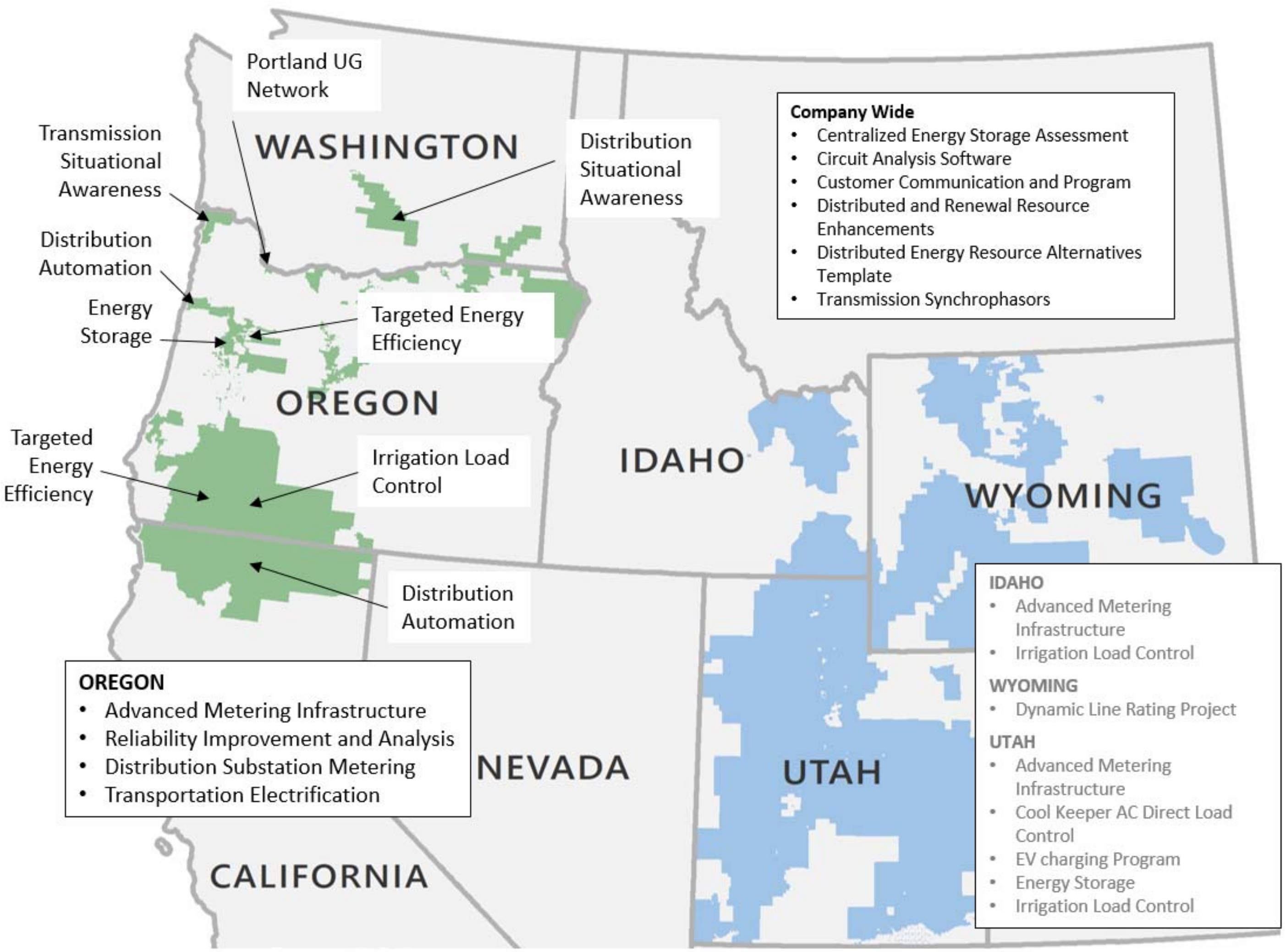


Figure 2 – PacifiCorp Oregon Grid Modernization Projects

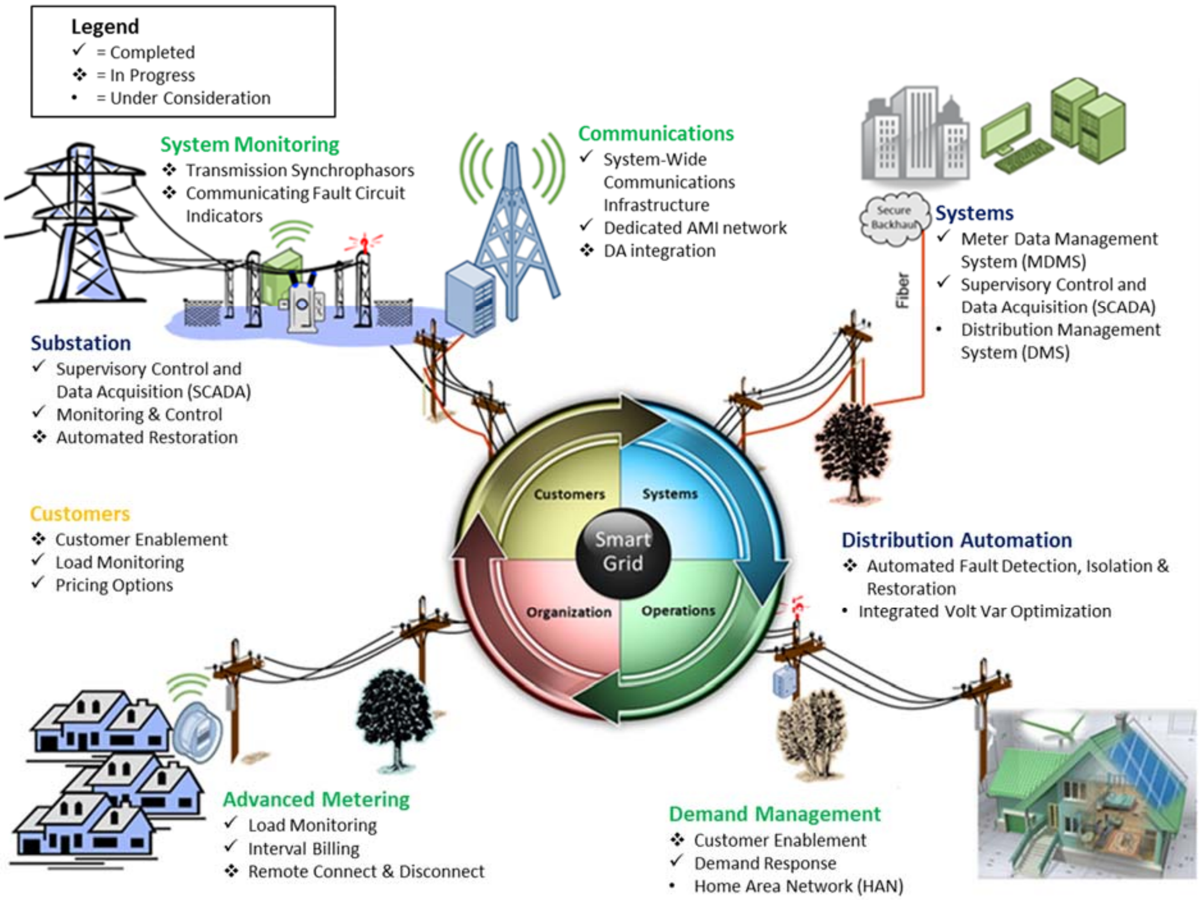


Figure 3 – Select Smart Grid Concepts

V. Status of Grid Modernization and Smart Grid Investments

A. Advanced Metering Infrastructure

PacifiCorp is installing AMI across the company's Oregon service territory. The system consists of head-end software, FAN, and approximately 589,000 meters. Itron, formerly Silver Springs Network, is the vendor providing the system, including meter installation services. Energy Usage web and mobile pages have been built for use in sharing interval consumption data with customers.

The project is on schedule and on budget. The Oregon roll out is on track to be complete in 2019. PacifiCorp is in the early stages of quantifying savings identified in the 2017 Smart Grid Report because the meter installs are two-thirds complete. The tables in Appendix D provide an update on the delivery of business case savings. As of March 31, 2019, over 440,000 smart meters have been installed in the areas listed in Table 2.

Table 2 - Summary of AMI Installation & Functional Phases

Area	Notices to Customers	Meters Deployed	Pinging	Disconnect - Reconnect	Customer-Facing Aids
Willamette Valley	x	x	x	x	x
Klamath Falls	x	x	x	x	x
Medford	x	x	x	x	x
Grants Pass	x	x	x	x	x
Roseburg	x	x	x	x	x
Coos Bay	x	x	x	x	x
Astoria	x	x	x	x	x
Portland	x	x	x	x	x
Hood River	x	x	x	x	x
Central Oregon	Underway	Underway	Underway	Q3 2019	Q2 2019
Eastern Oregon	Underway	Underway	Underway	Q3 2019	Q2 2019

1. Functionalities

Outage communications

Meter pinging and last gasp functionalities are in place for most of the 440,000 meters installed. Dispatch and operation organizations are using meter ping functionality during outage restoration efforts. They are also utilizing last gasp messages to augment customer calls and create outage tickets in PacifiCorp's outage management system once they pass analysis. PacifiCorp is implementing business process changes to facilitate outage management functionality.

Remote connections/disconnections

Remote connect functionality is performing as expected; in certain instances PacifiCorp can restore power while the customer center representative is still on the phone with the customer, while in other cases service can be disconnected when rental properties have tenant changes (with appropriate landlord communication).

Customer reconnects have been automated and are triggered by payment of an amount that has been quoted to a customer. The average time for a service reconnect is less than four minutes from the time the payment information is received.

Very few remote connects fail. Local power outages and temporary meter obstructions may occur that can cause remote operations to fail. Remote operations are monitored and failed operations are retried. If the remote operation is still unsuccessful, the request is routed to a field employee for manual completion.

Operational Efficiencies

Meter reading and collection workforce reductions are on schedule. PacifiCorp is also reducing vehicles numbers. Concurrently, a centralized department responsible for monitoring AMI system performance has been established.

Meter outage notifications and "pinging" of meters are actively being utilized in power restoration efforts. Outage trouble orders are being generated from meter outage notices in the Willamette Valley, Klamath Falls, and Northern California areas and will be expanded to other areas as network optimization is completed. The impact on outage management processes and reliability metrics can be better determined after more areas are incorporated and more operational data is available; however, the benefits are apparent as we are often aware of an outage prior to the customer reporting it.

2. Customer Engagement

AMI Deployment Communication

PacifiCorp uses a variety of media (radio, TV, paper, social media) in each area to notify customers before meter installs. PacifiCorp also directly notifies its customers of the meter replacements. Postcards are mailed to customers approximately 30 days ahead of installation. Customers receive a letter describing the installation process two weeks in advance of receiving a new meter and a phone call is placed one to two weeks prior to installation. Installation technicians knock on each door prior to accessing a meter to notify customers of their presence and afford them the opportunity to disconnect electronics ahead of a brief power interruption which occurs when the meter is exchanged. The technician leaves a door hanger once the new meter is installed. If the technician is unable to install the meter, for any reason, they leave a door hanger requesting the customer call to make an appointment. Approximately two to four weeks after the meter is exchanged, customers receive a postcard encouraging them to log on to their account to view interval consumption data, etc.

PacifiCorp holds community workshops to address customer concerns, specifically around radio frequency (RF) exposure, privacy and accuracy. Participation levels have varied from community to community. The information has generally been well received. PacifiCorp has also met with community leaders across Oregon to answer questions and better prepare them to respond to constituents' concerns. Input regarding opt-out fees received during these workshops has been incorporated into recent opt-out tariff[4] design.

Educational materials have been developed and are being made available for customers. They include a small quarter-fold card that addresses basic questions on smart meters. A more detailed smart meter packet, which delves further into health, privacy, accuracy and safety topics, is also available for customers. The packet includes several white papers from non-company sources that focus on RF exposure and also addresses the customer's ability to opt-out. The education material has helped keep the opt-out rate for Oregon below 1.28 percent as of mid-July 2019.

PacifiCorp is coordinating with the city of Independence to schedule a follow-up community meeting to discuss the value customers are deriving from smart meters. This was one of the first areas completed, with meters in-service for over a year. PacifiCorp will consider customer input from community meetings which will be used to inform changes in presentation of interval data in web applications.

Each quarter, PacifiCorp utilizes Market Strategies, Inc. to survey residential customers to determine levels of satisfaction. Market Strategies is provided with a list of zip codes for areas that have recently had a smart meter installed. Based on the zip codes and focusing in on seven key questions asked of customers (Overall Satisfaction, Overall Feelings, Overall Trust, Concern and Caring towards Customers, Friendly and Courteous Employees, Knowledgeable Employees, and Information on reducing Costs) a score is provided on percentage of satisfaction. The goal is to review satisfaction in areas with smart meters installed versus areas that have not had a smart meter installed. Seven key areas of satisfaction have been tracked since installs started in 2017 and will continue through the end of the project. Following is the results for 2019.

[4] https://www.pacificpower.net/ya/smart-meters/faq0.html#opt.
https://www.pacificpower.net/about/rr/ori.html (See Schedule 300).

Table 3 - 2019 Market Strategies Survey Results

		PACIFIC POWER - Residential Customers					
		Q1 2019		Q2 2019		Q1 2019 Difference	Q2 2019 Difference
		Inside SM Zips	Outside SM Zips	Inside SM Zips	Outside SM Zips	Inside SM Zips - Outside SM Zips	Inside SM Zips - Outside SM Zips
	n=	860	393	855	196		
Q1. First, thinking about your experiences with Pacific Power as your electric utility, how satisfied are you with Pacific Power?	%6-10	90%	93%	93%	95%	-3%	-2%
	%8-10	71%	**79%**	75%	**80%**	**-8%**	**-6%**
Q2. Please rate your overall feelings toward Pacific Power in general.	%6-10	88%	**94%**	92%	**94%**	**-5%**	**-3%**
	%8-10	73%	**78%**	76%	**80%**	**-5%**	**-4%**
Q8. Being a company you can trust	%6-10	79%	**84%**	81%	**87%**	**-5%**	**-6%**
	%8-10	64%	**70%**	67%	**72%**	**-6%**	**-5%**
Q28. Showing concern and caring toward customers	%6-10	77%	82%	81%	84%	-5%	-3%
	%8-10	64%	**70%**	67%	70%	**-6%**	-4%
Q32. Having friendly and courteous employees	%6-10	84%	84%	85%	86%	0%	-1%
	%8-10	73%	72%	75%	75%	1%	0%
Q33. Having knowledgeable and well-trained employees	%6-10	81%	82%	82%	85%	-1%	-3%
	%8-10	71%	71%	71%	73%	0%	-2%
Q60. Providing information on how to control your electricity costs	%6-10	75%	79%	77%	**83%**	-4%	**-6%**
	%8-10	55%	57%	55%	**64%**	-2%	**-8%**

** red text indicates significant difference between Inside and Outside SM Territory*

For 2019, focus has been on communicating with customers via earned media in order to emphasize the availability of smart meter functionality; namely access to interval use date. Customers are encouraged to create an online account which will allow them to see and manager their energy consumption.

Proactive Tracking of AMI Remote Operations

Remote functionality includes the ability to ping a meter and connect/disconnect a meter remotely. These functionalities are activated once meter installations are largely complete in a given area and sufficient mesh connectivity levels have been reached.

Remote connects and disconnects are monitored by a centralized group of Metering Business Systems Support (MBSS) employees who operate the AMI system during normal work hours. Monitoring is handed off after-hours to PacifiCorp customer care centers. Actual remote reconnect times are tracked for reporting purposes. Business processes are in place to monitor and respond to the one-off instances where remote connect functionality fails. Between the first of January and mid-July of 2019, twenty-eight failures out of 21,341 remote connect operations had to be routed to the field to be manually worked due to remote connect failures. The failures were due to loss of communication with the meter and/or tampering that resulted in the meter being inoperable.

3. Customer Centric Tools and AMI Features

The usage of online energy management tools is being tracked to determine the level of customer engagement. As previously mentioned, follow-up community meetings will be held to discuss customer perceptions and value proposition.

Energy Usage Graph

Customers have access to energy usage graphs online. The graphs depict near real-time hourly, daily, weekly, and monthly consumption typically within two to four weeks of receiving their new meter.

The following graphic in Figure 4 depicts an example from the Pacific Power website where a customer can view energy usage. This same data is also available on the Pacific Power mobile application and via billing notifications.

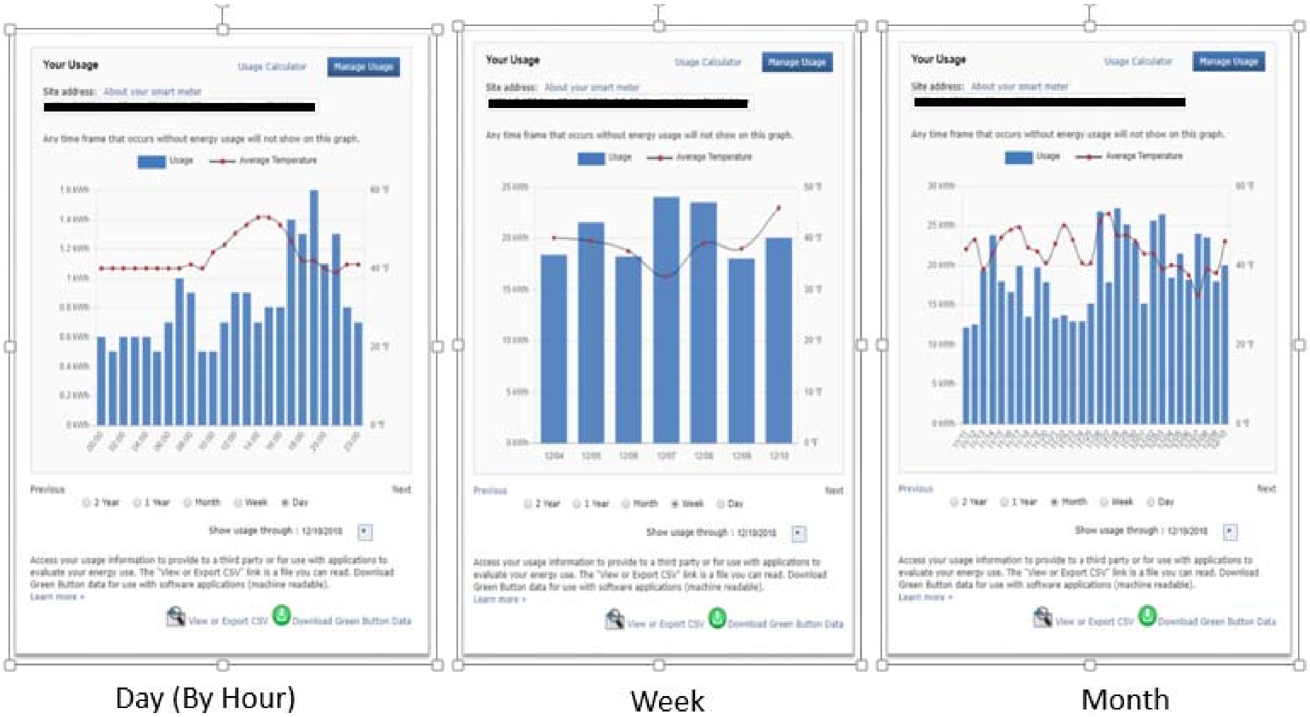


Figure 4 – Energy Usage Graphs

Bill Projections

Functionality that projects customer electric usage bills is currently in place for customer use. Customers also have the ability to establish a billing threshold, entering a target dollar amount online in a very simple manner. If a billing projection exceeds the target amount, the customer is notified via text or email. Subsequent communications continue to occur weekly in order for the customer to see if their energy consumption decisions are moving their bill projection downward. Less than one percent of Oregon customer accounts have set bill notification thresholds as of mid-July, 2019.

The following graphic in Figure 5 depicts an example from the Pacific Power website where a customer can set up bill projection notifications, as well as their other communications preferences.

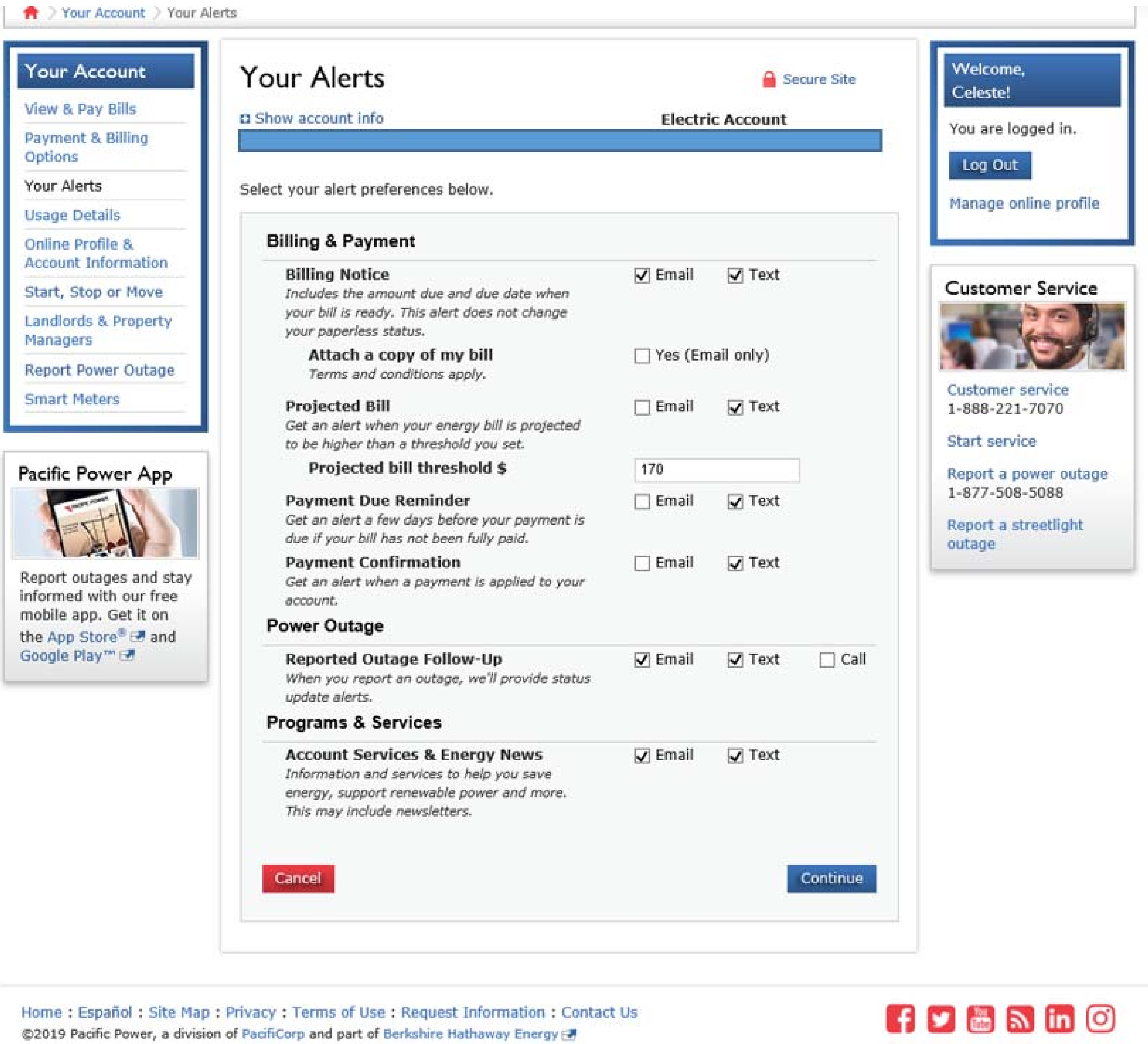


Figure 5 – Bill Projection and Outage Follow-Up Options

4. <u>Mitigating Technology Obsolescence Risk</u>

Itron, Inc. acquired Silver Spring Networks, Inc. in January 2018. Itron has stated they intend to merge the Itron and Silver Spring Networks head-end AMI systems in the near future. They have also stated that they will provide an executive level roadmap by December 31, 2019.

PacifiCorp remains current with network application upgrades for the AMI head-end system and will complete a 4.10 to 4.14 version upgrade by the fourth quarter 2019 to stay current with Itron's standard support model.

AMI meters have a 25-year useful life, however some technologies can become unsupportable five to 10 years after commissioning. To mitigate these risks, PacifiCorp is adopting the following strategies:

- Vendors provide support commitments;
- Open-protocol network;
- An AMI road map that includes hardware and software updates; and:
- AMI hardware and software maintenance by component:
  - Annual operational meter testing,
  - FAN access points and relays are continuously monitored,
  - FAN access points and relay batteries are on a replacement cycle,
  - AMI head-end servers are on a replacement cycle, and
  - AMI head-end applications are upgraded by the vendor.

B. Transmission Network and Operations Enhancements

1. Transmission Situational Awareness

A three-phase monitoring system utilizing Cleaveland/Price's LineScope includes a feature to operate as a Communicating Faulted Circuit Indicator (CFCI). LineScopes have been piloted on the transmission system in Oregon which, through the Energy Management System (EMS), have increased transmission situational awareness. PacifiCorp plans to install additional sets of the LineScope monitors for Oregon 69 kilovolt (kV) and 115 kV lines; as the device's capabilities matures it will consider expanding that deployment to additional locations for additional awareness. The LineScope devices are being enhanced to indicate direction and distance of a line fault in EMS, see highlighted circle in Figure 6. The pilot installation in Astoria was found to have resulted in more rapid line restoration during the fall and winter of 2018/2019[5].

[5] Generally, the company considers at least five years of data to establish transmission outage trends. PacifiCorp has observed that on at least one location where LineScopes were installed, grid operations identified a faulted segment and restore power in 14 minutes. Previous to their installation, restoration would have required callout of response personnel, followed by patrolling the line, which is 78 miles, much of which is difficult to access from roadways.

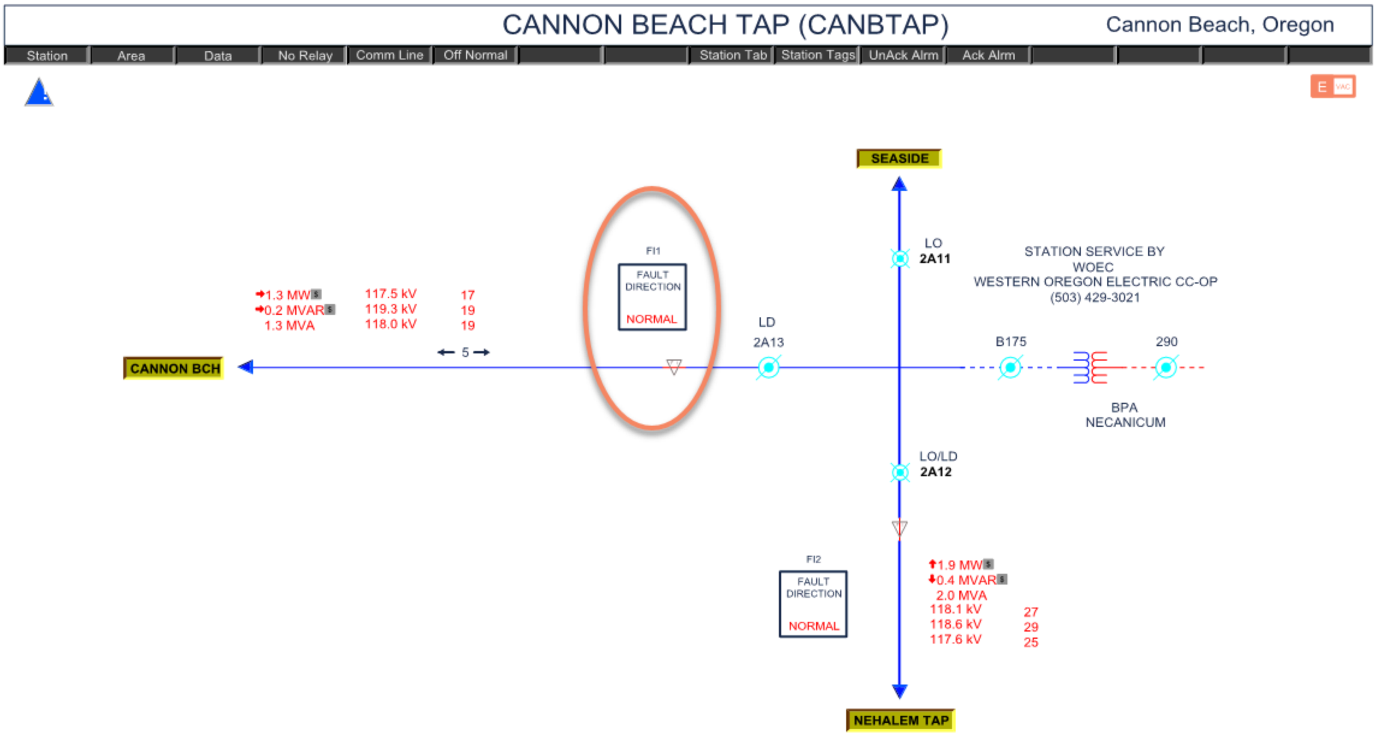


Figure 6 – Transmission CFCIs Pilot – EMS Screen

2. <u>NERC Reliability Standard MOD-033-1 and PRC-002-2</u>

Definitions

The North American Electricity Reliability Corporation (NERC) standard MOD-033-1, *Steady-State and Dynamic System Model Validation*, establishes consistent validation requirements to facilitate the collection of accurate data and the building of planning models to analyze the reliability of the interconnected transmission system. MOD-033-1 became effective in 2017.

NERC standard PRC-002-2, *Disturbance Monitoring and Reporting Requirements*, ensures adequate data is available to facilitate analysis of Bulk Electric System Disturbances.

Digital Fault Recorders (DFR)/ Phasor Measurement Unit (PMU) Deployment

To meet compliance with NERC MOD-033-1 and PRC-002-2 standards, PacifiCorp has installed over 100 Multifunctional DFR which include PMU functionality. The installations are at key transmission and generation facilities throughout its six-state service territory, generally place on WECC critical paths. PMUs provide sub-second data for voltage and current phasors, which can be used for MOD-033-1 event analysis and model verification. DFRs have a shorter recording time with higher sampling rate to validate dynamic disturbance modelling per PRC-002-2. Of the 100 total PMU installations, 22 are installed among 13 generation facilities with individual or aggregate capacities of 75 MW or larger. Since 2017, PacifiCorp has also required all new generation facility interconnections meeting the 75 MW threshold to install PMUs as part of the interconnection. Although there are several active queued requests larger than 75 MW with the PMU installation requirement, including some that have executed Interconnection Agreements with the company, none of the projects with this new requirement have been placed into service as of July 2019.

DFR/PMU Placement

The placement of PMUs is not proscribed by the MOD-033-1 standard. PacifiCorp developed an internal placement philosophy:

- First, at large generators at 75 megawatts (MW) or larger.
- Second, at city center loads or where transmission lines converge.
- Third, all 500 kV, 345 kV, and 230 kV busses were considered.

The placement methodology of DFRs is in accordance with Attachment 1 of PRC-002-2 which requires monitoring on Bulk Energy System (BES) buses and BES Elements for which sequence of events recording (SER) and fault recording (FR) data is required. The placement included locations where Dynamic Disturbance Recorder (DDR) data is required based on the Reliability Coordinator's DDR List.

DFR/PMU Next Steps

Data from the PMUs will be delivered to a centralized Phasor Data Concentrator storage server where offline analysis can be performed by transmission operators, planners, and protection engineers. Installation of the communications and data transfer systems between the individual PMUs and the PDC is underway and planned for completion by the end of 2019. Additionally, DFR data is planned to be downloaded manually at substations.

Transmission planners will use the phasor data quantities from actual system events to benchmark performance of steady-state and transient stability models of the interconnected transmission system and generating facilities. Using a combination of phasor data from the PMUs and analog quantities currently available through Supervisory Control and Data Acquisition System (SCADA), transmission planners can set up the system models to accurately depict the transmission system prior to, during and following an event. Differences in simulated versus actual system performance will then be evaluated to allow for enhancements and corrections to the system model.

Model validation procedures are being evaluated, in conjunction with data and equipment availability, to fulfill MOD-033-1. Creation of a documented process to validate data that includes the comparison of a planning power flow model to actual system behavior and the comparison of the planning dynamic model to actual system response is ongoing.

Sub-second PMU data has not been shown to substantially increase situational awareness or grid operator action beyond current four second SCADA data. PacifiCorp's System Operations is not utilizing PMU data in its real-time operations. PacifiCorp has a robust transmission EMS with SCADA over 179,000 status points and 116,000 analog points which provide system operators with real-time system data every four seconds for maintaining situational awareness.

PacifiCorp will continually evaluate potential benefits of PMU installation and intelligent monitoring as the industry considers PMU in Special Protection, Remedial Action Scheme, and other roles that support transmission grid operators.

3. Energy Imbalance Market

PacifiCorp and the California Independent System Operator (ISO) launched the EIM November 1, 2014. The EIM is a voluntary market and the first Western energy market outside of California. See Figure 7. The EIM now includes Companies from a Canadian province and eight states in the Western US: British Columbia, Arizona, California, Idaho, Nevada, Oregon, Washington and Wyoming—which uses California ISO advanced market systems to dispatch the least-cost resources every five minutes. For a list of existing and pending EIM participants see the Western EIM website[6]. PacifiCorp continues to work with the California ISO, existing and prospective EIM entities and stakeholders to enhance market functionality and support market growth.

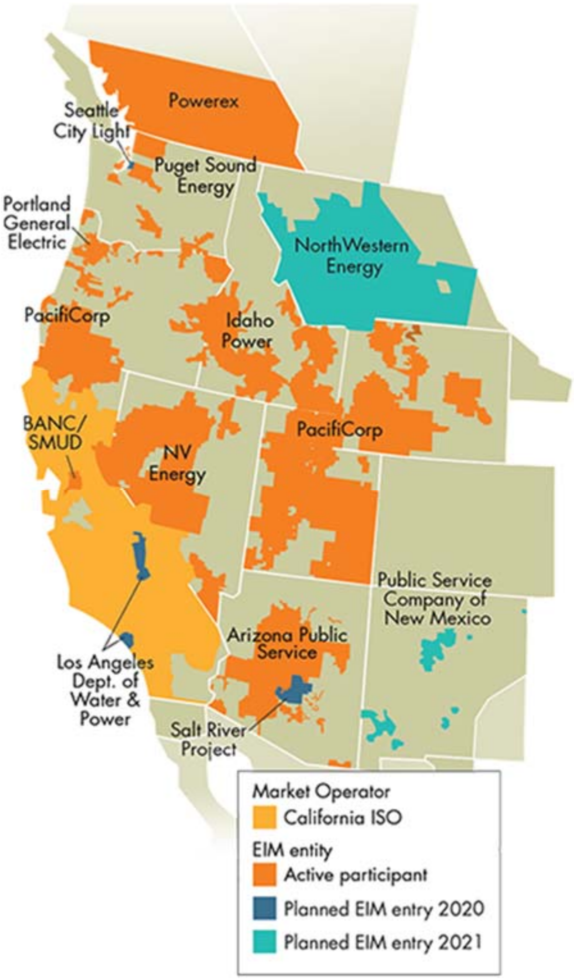
The EIM has produced significant monetary benefits for its participant members ($650.26 million total footprint-wide benefits as of March 31, 2019, accumulated since November 2014), quantified in the following categories:

- More efficient dispatch, both inter- and intra-regional, by automating dispatch every 15 minutes and every five minutes within and across the EIM footprint;
- Reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and

[6] https://www.westerneim.com/Pages/About.

- Reduced need for flexible reserves in all EIM balancing authority areas, also referred to as diversity benefits, which reduces cost by aggregating load, wind and solar variability and forecast errors within the EIM footprint.

Figure 7 – EIM Market Participant Map



A significant contributor to EIM benefits are transfers across balancing areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the ISO to serve California load. As such, the transfer volumes are a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the five- and 15-minute market dispatch intervals.

4. Cybersecurity

Potential cybersecurity threats to the utility industry range from energy theft customer to a foreign nation-state attack. In particular, smart grids may be vulnerable to three primary threats: customer or public attacks, insider attacks, and terrorist or nation-state attacks. To defend against these vulnerabilities, PacifiCorp has implemented a comprehensive, layered approach to cybersecurity, which has been extended to incorporate those elements part of the smart grid.

Project Description

PacifiCorp uses a multi-tier approach to smart grid security, including compliance with National Institute of Standards and Technology (NIST) security guidance, audits, penetration tests, technical controls, and security monitoring. NIST publishes a comprehensive set of security controls (NISTIR 7628, *Guidelines for Smart Grid Cyber Security*) for smart grid systems. PacifiCorp and its AMI vendor have aligned with these security controls.

PacifiCorp engaged a third-party security firm to audit both the company and its AMI vendor against the NIST smart grid security controls as part of the Oregon AMI project. In addition, the AMI vendor must undergo an annual service organization controls audit covering the scope of services under the contract and provide the results to PacifiCorp. The AMI system was also subjected to penetration testing to ensure the audited controls are performing as expected.

The AMI-specific audits and penetration tests were useful exercises to revalidate and reinforce lessons learned from our company-wide penetration tests and audits, conducted by a separate firm. The results corroborated each other, increasing our confidence that our remediation efforts were appropriate and thorough. The penetration test also helped validate plans and schedules to replace legacy technology. In many cases our legacy asset replacement and upgrade schedules were appropriate based on the risk level, and in a few cases the results justified accelerating certain scheduled upgrades. Specific findings and details are highly sensitive in nature and are protected accordingly.

PacifiCorp's information security team was actively involved in the system design process to ensure that appropriate technical controls were implemented. Controls include:

- KeySafe and critical operations protector hardware devices that protect meter encryption and provide a fail-safe against large-scale disconnect operations;
- Multi-factor authentication;
- Network segmentation to prevent unauthorized access to smart grid systems;
- Web application firewalls to inspect web traffic for potential attacks.

The AMI vendor operates a 24/7 security operations center that is responsible for monitoring the meters, access points and vendor-provided systems. Its security infrastructure includes comprehensive log monitoring, threat prevention and detection systems, malware detection, network traffic capture, anomaly detection, and vulnerability management.

C. Substation Operations Enhancements

Substation operations enhancement projects include, but are not limited to, centralized energy storage and meter replacement.

Centralized energy storage includes large centralized storage resources, such as electrochemical batteries, Pumped Hydroelectric Energy Storage (PHES), compressed air energy storage (CAES) 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 reliance on environmental conditions, such as wind or sun. The generation output of these resources cannot be increased and has high opportunity costs when generation is decreased unexpectedly. Providing service to the electric grid becomes progressively more challenging as the amount of the grid's energy requirements are increasingly served from these intermittent resources. Two methods to fill this generation gap without the use of dispatchable resources are demand response (DR) programs and energy storage, whether local or centralized.

1. Energy Storage

Integrated Resource Plan

PacifiCorp retained Burns & McDonnell Engineering Company to evaluate various renewable energy resources[7] in support of the development of the 2019 Integrated Resource Plan (IRP) and associated resource acquisition portfolios and/or products. Preliminary Summary Tables (IRP Assessment) were presented at a workshop[8]. The full 2019 IRP was not available at the time of this report. The IRP Assessment is screening-level in nature and includes a comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy, storage, and combined renewable energy/storage technologies:

- Single Axis Tracking Solar
- Onshore Wind
- Energy Storage:

[7] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Renewable_Resources_Assessment_for_the_2019_Integrated_Resource_Plan.pdf.

[8] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Table_6.1-6.3-TRC_for_Supply-Side_Resource_Options_19_IRP_for_PDF.pdf.

  - PHES
  - CAES
  - Li-Ion Battery
  - Flow Battery
- Solar + Energy Storage
- Wind + Energy Storage

Each renewable and storage resource is defined within the IRP Assessment which includes general and technology specific assumptions as well as explanation of cost inclusions and exclusions.

The IRP Assessment contains preliminary information in support of the long-term power supply planning process. Any technologies of interest to PacifiCorp shall be followed by additional detailed studies to further investigate each technology and its direct application within long-term plans.

Oregon Legislation HB 2193

On June 15, 2015, the Oregon legislature passed House Bill (HB) 2193. HB 2193 requires electric companies to submit energy storage project proposals to the Commission and, if authorized by the Commission, procure one or more qualifying energy storage systems (ESS) with the capacity to store at least five (5) megawatt-hours (MWh) of energy by January 1, 2020.

Project #1 – Utility-Owned Distributed Storage Pilot

Background

On December 29, 2017, PacifiCorp filed the Energy Storage Potential Evaluation and Energy Storage Project proposals with the Commission. Further, in alignment with PacifiCorp's strategy and vision regarding the expansion and integration of renewable technologies, the company proposed a utility-owned targeted ESS pilot project.

A phased pilot approach evaluates a unique opportunity with a single customer to study distributed storage applications alongside a blend of renewable and conventional generation. This project can inform future investment and test how energy storage can be used as a distributed resource within the PacifiCorp network.

Phase I

Install a single, utility-owned energy storage device to address historic outage characterization on a specific feeder, validate modeling through field test data, create a research platform, and optimize energy storage controls and integration on PacifiCorp's network.

PacifiCorp has contracted an owner's engineer to aid in project development and is progressing on the Phase I project to build an ESS on circuit 4M182, fed from the Hillview substation in Corvallis, Oregon. The current topology of 4M182 consists of a 20.8 kV radial distribution system with a peak load of 20 MW. The intent of this project is to integrate the ESS into the existing medium voltage distribution system with the capability and flexibility to potentially extend into a future micro grid system that would connect into the 20.8 kV network. The minimum system size is:

- Energy Requirement of six (6) megawatt-hours,
- Power requirement of two (2) megawatts.

The current timeline for completion of the project:

- Project Authorization — September 2018 (complete)
- Issue and Award RFP for OE — December 2018 (complete)
- Land Acquisition/Lease — August 2019*
- Develop OE Tech Specs — October 2019
- Jurisdiction Permits — November 2019*
- Issue and Award RFP for Engineer, Procure and Construct — December 2019
- Initiate Construction — January 2020
- Construction Complete — September 2020
- Complete Interconnect — April 2021
- Project In Service/Commissioned — May 2021

* Medium-high risk of delaying construction start

Phase II

Add an additional energy storage device to pilot distributed storage, optimize use cases per Phase I results, explore tariff structure and ownership models and continue research.

Project #2 – Community Resiliency Pilot

In 2018, PacifiCorp's application was approved by the Commission under UM 1857 through a settlement agreement. As part of the application PacifiCorp proposed a Community Resiliency Pilot (Pilot) with customer-sited energy storage. The Pilot aims to expand upon PacifiCorp's existing understanding of energy storage within the communities it serves in Oregon. PacifiCorp recently issued a request for proposal (RFP) to identify a qualified consultant that has robust knowledge of customer-sited energy storage and is capable of conducting onsite technical assistance for the company's customers. Through the RFP, PacifiCorp seeks to explore available technologies to address resiliency needs of specific facilities critical to emergency response or disaster recovery, while allowing the company to learn about the technologies, costs, benefits, use cases, and feasibility associated with customer-sited energy storage.

PacifiCorp is currently in the final stages of contracting with a consultant, selected through a competitive RFP, to perform the technical assessments for Phase 1 of the pilot. PacifiCorp anticipates site visits starting in September 2019, with studies completed by the end of the year.

PacifiCorp has developed a list of potential sites; outreach to community representatives and facility managers will begin in earnest once the consultant is on board. PacifiCorp intends to coordinate with the ETO to identify potential sites for technical assessments to avoid duplicating efforts, as the ETO is exploring similar programs in PacifiCorp's service territory.

2. Distribution Substation Metering

Substation monitoring and measurement of various electrical attributes is seen as a necessity due to growing levels of distributed energy resources. Enhanced monitoring helps to resolve limited visibility about loading levels as well as provide information on load shapes, customer usage patterns as well as inform about reliability and power quality events.

Project Summary

The Oregon meter replacement project has begun installation of enhanced meters. A preliminary wave of approximately 20 meter replacements will be fully deployed by the end of 2019.

The project is utilizing Electro Industries/Gauge Tech Shark 250 meters (Shark 250) as a low cost solution for replacing existing JEM1 and GE analog meters. The Shark 250, with potential cellular communication, is being evaluated for non-SCADA connected areas of the grid. The project will also continue to evaluate if the Shark 250 provides cost effective situational awareness and control.

SCADA has been the preferred form of gathering load profile data from distribution circuits, however SCADA systems can be expensive to install and additional equipment is required to provide the data needed to perform analysis to diagnose waveform and harmonics issues; when system data, rather than data and control is important, SCADA is no longer the best option for accessing this information. The advanced substation metering pilot is intended to provide an affordable option for gathering required substation data. PacifiCorp's current work plan includes:

- Purchase and install advanced substation meters at distribution substations with limited or no communications;
- Ensure all substation meters installed as part of this program are enabled with remote communication capabilities; and
- Implement a data management system to automatically download, analyze and interpret data downloaded from all installed substation meters.

Future Action

PacifiCorp is at the early stages of considering additional Shark 250 features that can act as a system control point without the installation of a more expensive remote terminal unit (RTU).

The Shark 250 microcomputer hardware allows the digital meter to report power quality and line loading information electronically to both real-time data historian databases and dispatch systems, however, the current cell pack communication infrastructure restricts the data pull frequency to every 2 hours. Data is currently stored locally. Data retrieval for EMS requires a technician to collect and import the data to PI in person.

As the volume of data created by equipment monitoring sensors, power quality substation meters, customer revenue meters, and protection equipment increases, the value of the data diminishes unless an effective diagnostics tool is part of the implementation. Acquisition and implementation of a software called PQView provides users a refined view of power quality information pertinent to their location. Figure 8 shows PQView's web dashboard called PQWeb which focuses on feeder level metering and:

- Lists power quality events,
- Shows abnormal wave forms,
- Geographically maps the issue by meter location.

PacifiCorp's Regional Business Managers (RBMs), who act as customer representatives to large power customers, will be able to research detailed power quality logs every 2 hours.

As part of the Energy Storage Potential Evaluation Plan under UM 1857, PacifiCorp will provide notice to the Oregon Commission if a near-term non-wires solution is competitive with the cost of a facility upgrade.

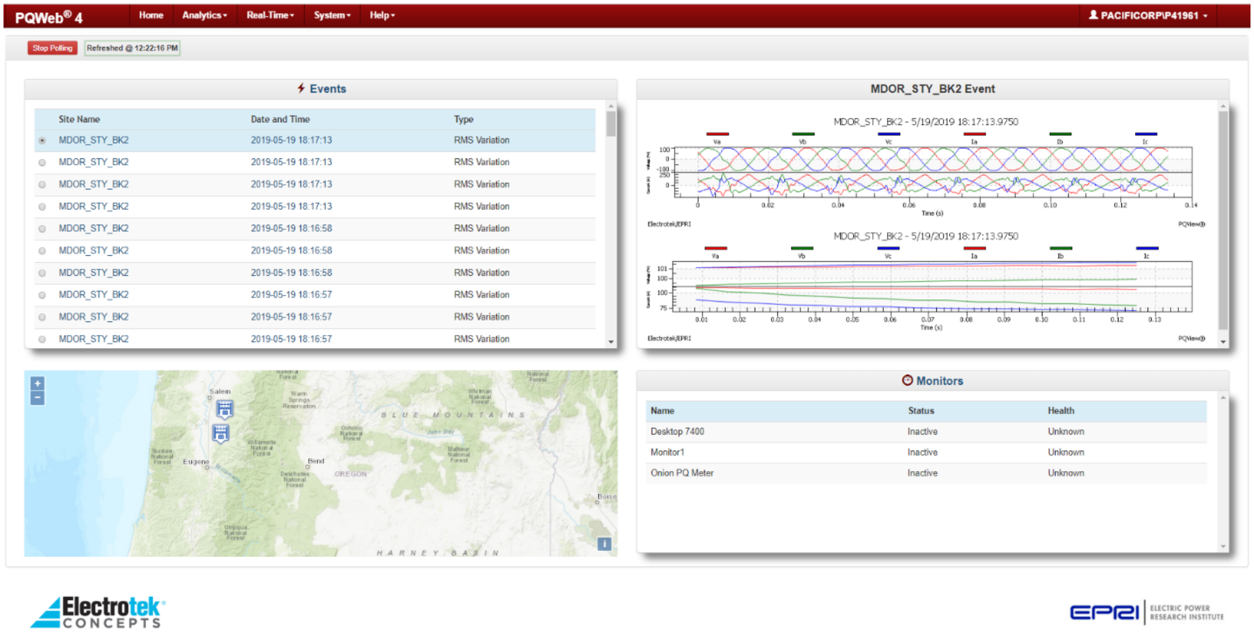


Figure 8 – PQWeb[9]

PQView is planned to provide faster response times to power quality events that adversely impact customers. Two notable aspects of PQView are:

- Breaker Trip correlation to power quality events.
- RBM online access with email notification of power quality events.

PQView has access to all Shark 250 substation meters. PacifiCorp plans to further integrate non-company customer revenue meters which will allow assessment of power quality events occurring on the customer's side of the interconnection. As the coordination of breaker trips and power quality events is solidified, PacifiCorp will be able to identify the magnitude, source, and time of the event, and work with customers proactively to resolve their power quality concerns.

D. Distribution Field Communication

1. Modeling and Information Exchange

PacifiCorp is in the early stages of integrating advanced data sources (such as AMI) with its planning and engineering models. Methods to identify overloaded service transformers and apply customers' non-billable demand values to system models (e.g. CYME) are in their infancy due to the ongoing AMI rollout.

[9] http://www.pqview.com/pqweb/

PacifiCorp continues to evaluate distribution management systems (DMS) and has informally incorporated elements of the IEC 61968 best practice standard for exchanging information between electrical distribution systems. For example the AMI head-end architecture uses a service oriented architecture (IEC 61968-1) utilizing an enterprise service bus as an integration bus to communicate between these company systems:

- Customer Information System (CIS)
- Itron Meter Data Management System
- Outage Management System (OMS)

PacifiCorp included NIST security standards in its AMI architecture, similar to IEC's security approach.

There are a large number of hurdles which must be overcome to implement the concept underpinning IEC61968. These include, at a minimum, 1) determining which automation functions are contained at the device or at a central processor, and determining the logical mixture of both to effectively improve reliability and operational needs at the lease cost; 2) identification of systems and operational data retention in support of the device functionality, including data governance and retention policies such as SCADA system and/or containment as an event registrar in an Advanced Distribution Management System; 3) evaluating the need for reliable and pervasive communications systems including proper security and controls to support critical infrastructure operations; 4) development of proper security protocols and controls; 5) establishment of device backup and failover procedures in the event of a failure of any part of an automated system; 6) identification of obsolescence management strategies; 7) establishment of a Common Information Model to support extensions for Distribution; and, 8) development of training programs with properly trained engineering and operational staff to support the advanced systems being deployed.

2. Field Area Network

Numerous FAN consisting of approximately 900 pole-mounted devices, for the AMI system, have been put in place across the State of Oregon. Figure 9 shows a diagram of a deployed AMI FAN.

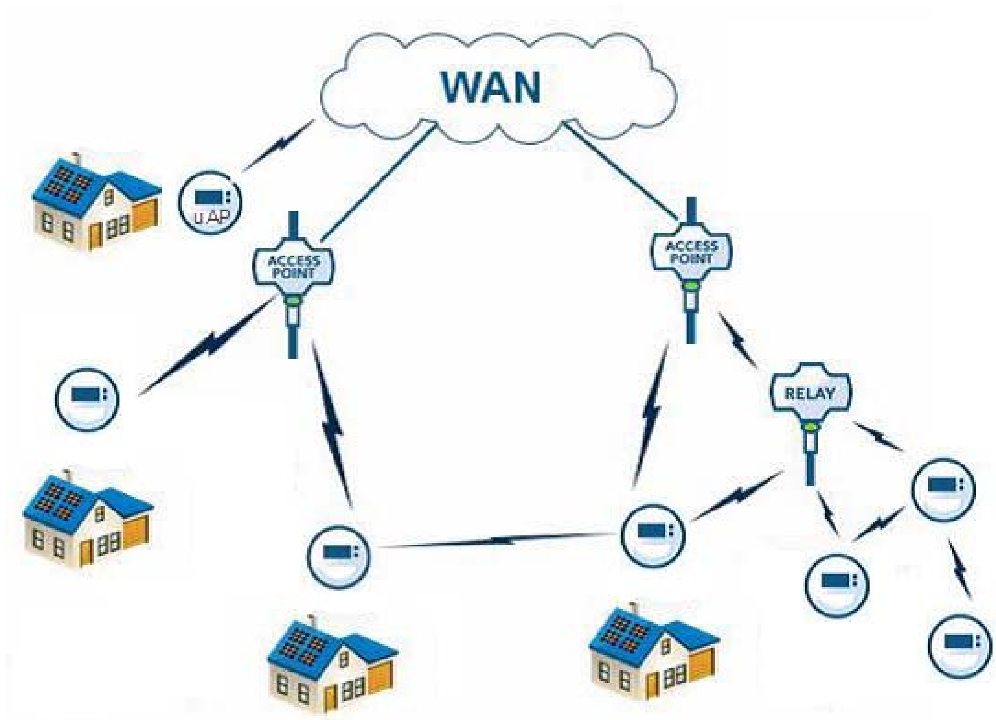


Figure 9 – Representation of AMI FAN

Figure 9 shows that AMI meters in a FAN speak to pole-mounted access point devices in order to relay consumption and meter data back to main databases. Multiple FANs link to create a wide area network. Communication can go either direction in the network. The customer operation system can speaks to the meters via the field area network in order to complete remote commands, including reconnects, disconnects, and service status.

Micro-access points are installed in areas where the FAN needs reinforcement or communications with a FAN is not feasible, see Figure 9. A micro-access point is essentially a meter with cellular capability. These micro-access points take the place of pole-mounted devices and can be used to mitigate access to meters that are difficult to connect to a FAN.

Figure 10 shows the proposed DA FAN uses the common deployed AMI access.

With all FAN deployments, PacifiCorp will continue to look for opportunities to increase its resiliency and operational integrity. Some of these currently being considered include deployment such as DA as well as advanced or dynamically reconfigurable protective coordination settings (such as modifying device settings for fire risks).

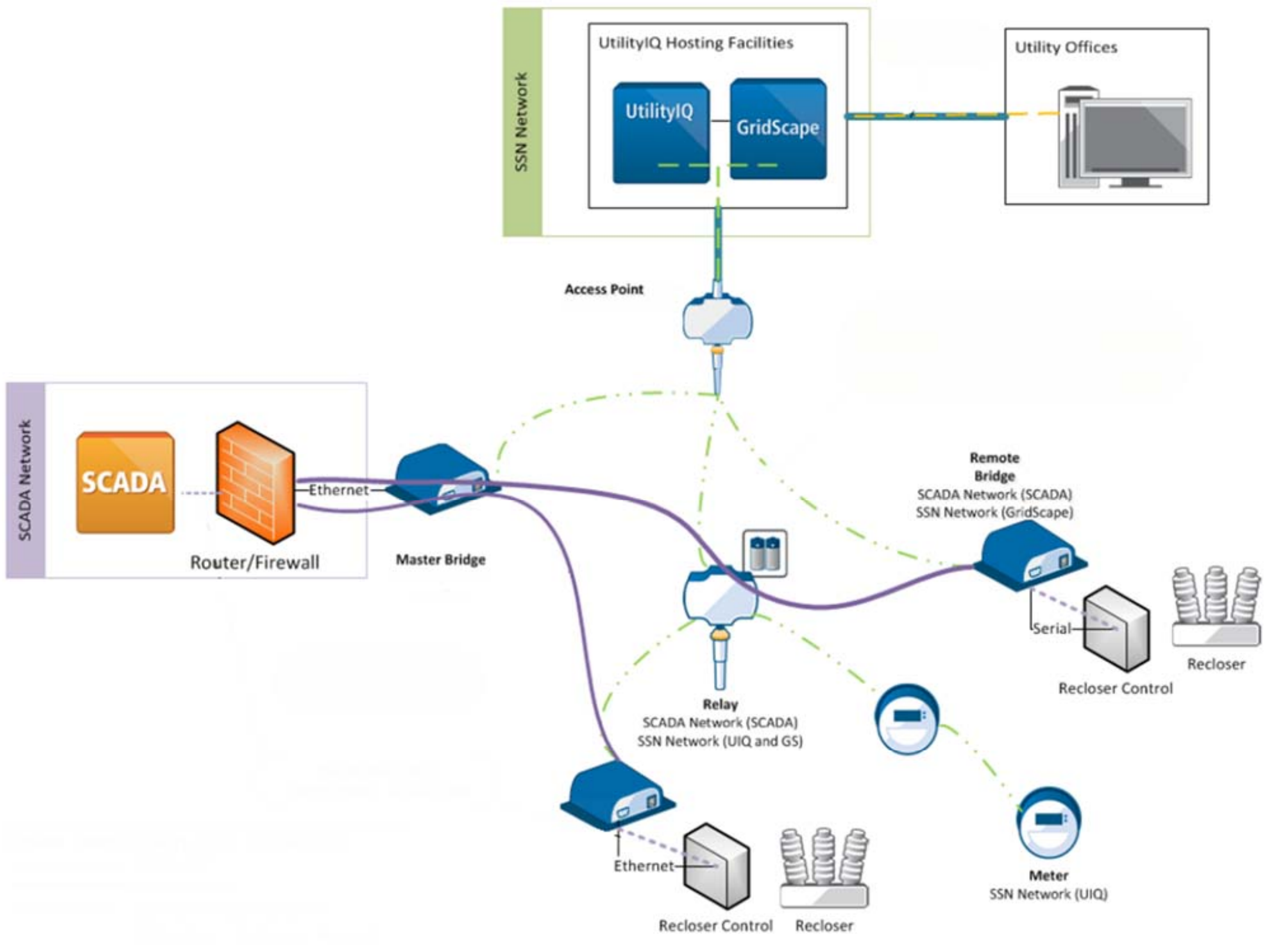


Figure 10 – Representation of DA FAN

3. <u>Trouble Call Initiation Intelligence</u>

PacifiCorp's customer call centers now receive ad hoc affected-customer notifications based on EMS or OMS status. The OMS platform differentiates between outages received by the call center and those reported by AMI. Customer call center tools initiate automatic power outage notifications which link EMS and OMS systems. Customers can setup communication preferences or opt-out.

Appendix D shows the system logic which automatically alerts customers effected by outages. A 15 minute outage notification delay allows operators to screen automated communications, limiting the communication of "false positive" signals.

The online customer preference center in Figure 5 allows the customer to select optional automatic power outage notifications. These notifications were implemented in 2018 and can provide estimated time of restoration and repair crew status to customers. Benefits include:

- Dispatch knowledge of effected customers.
- Proactive phone calls, texts, or email communication dependent on customer preference[10].
- Online outage maps[11] that are updated in real time.

4. Distribution Situational Awareness

a) Network Monitoring

The VaultGard Portland Low Voltage Secondary Network Project has been deployed with new network monitoring points. See Section V.E.2. for details.

b) RTU Pilot

Field information is being brought back to a SCADA connected RTU point at the Union Gap Substation (in Yakima, WA). The additional communication is planned to reduce the time required to recover from system disturbances by providing useful and timely information to region operations. Appendix B has details. Figure 11 shows an enhanced EMS screen with enhanced 'distance to fault location' from field recloser relays.

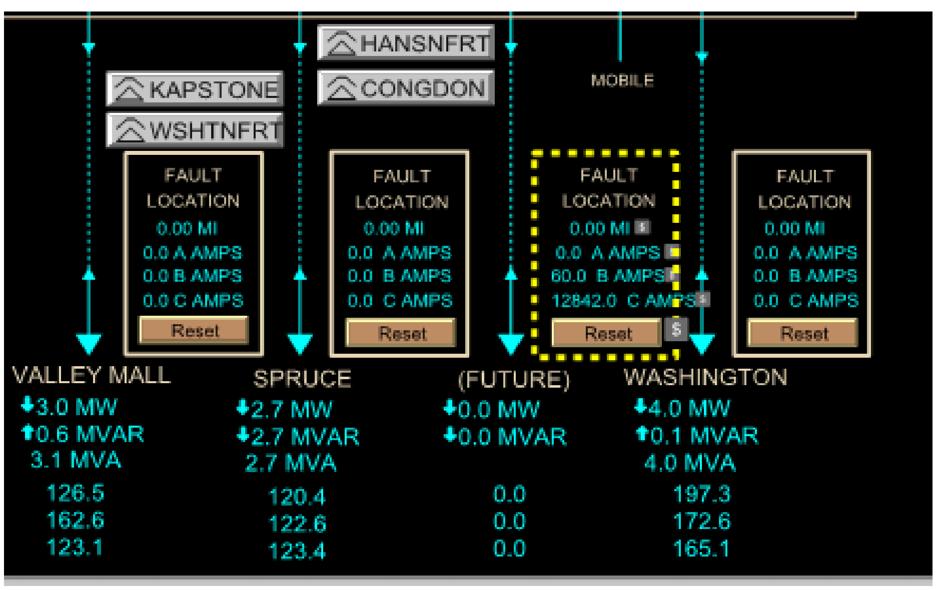


Figure 11 – Pilot VaultGuard EMS with Enhanced SCADA

[10] Phone calls are not made between 11:00 p.m. and 7:00 a.m.

[11] Oregon Outage Map: https://www.pacificpower.net/ed/po/oom.html.

5. AMI

a) AMI Mesh Restoration Lesson Learned

Shortly after deployment of the AMI outage management interface dispatchers noticed occasional small groups of last gasp messages coming into their system while meter pings and field checks showed no outage actually existed. PacifiCorp analyzed this issue using an event that occurred in Lincoln City in June 2018. The root cause was found to be due to the new capacity of the AMI meters to report large-scale momentary outages and power quality events. Prior to AMI, such events would only be captured in the real-time EMS system and would not present as an OMS outage. With the advent of AMI, anything that causes the meter to detect a voltage loss generates a last gasp and needs filtering.

The lesson learned was that large-scale outage events which effect the AMI mesh occasionally take longer to self-heal than expected. Meters that were expected to be online but had not re-connected sent out false outages. The white arrows in Figure 12 show the meters that sent false outages at the Lincoln City event. The Figure also shows a correlation between false outage and distance from the access points. The frequency of these events is less than 2% and well within the design tolerance for the mesh network. This is being addressed on multiple fronts:

- Business processes have been updated, to ensure Operators ping AMI meters to confirm outages.
- New AMI service territory locations are not enabled for outage detection until the network is optimized.
- Time-based filtering settings for AMI last gasps have been increased slightly to reduce the likelihood of delayed events.

The outage filtering occurs in the "AMI Head-End System" box in Figure 13 and delays customer notification by at least 15 minutes for internal processing. PacifiCorp has a cross-platform team that reviews and correlates momentary outages or power quality events. The goal of the review is to understand where opportunities for further tuning the mesh network by adding access points or micro access points exists. This review is done on a case-by-case basis across the service territory. After new AMI deployments, it takes a couple of months to collect enough data to pinpoint and optimize the area issues.

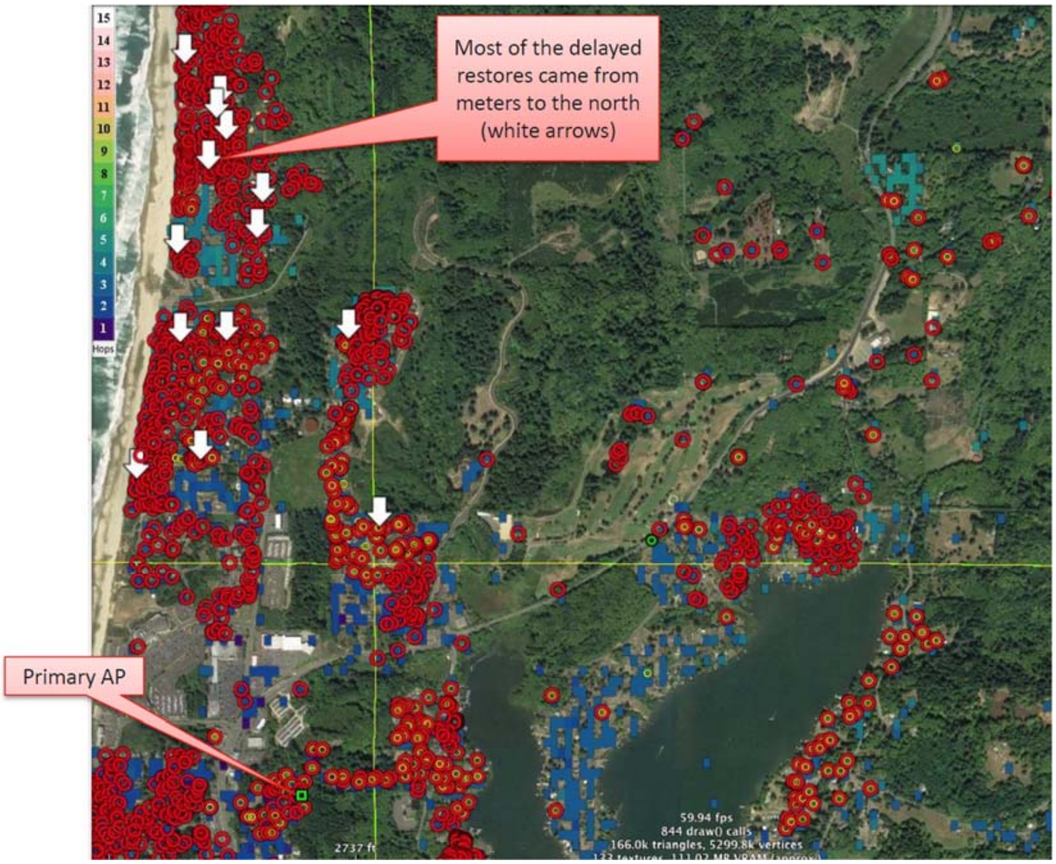


Figure 12 – Lincoln City AMI Mesh Restoration Issue

b) AMI Power Quality Awareness

With the deployment of AMI a system was developed to fill several solution gaps. The AMI Operations Center (AOC) operated by the MBSS group provides a user interface to manage the following functions:

- Track and report data creation and modification between CIS, AMI head-end system (Itron/Sliver Spring Networks) and the Itron Enterprise Edition data warehouse and provide error handling.
- Track and report processing of over air commands and provide error handling.
- Ping a single meter.
- Manage collection disconnect processing.
- Graphically view meter usage details.

System operators deployed an OMS feature called REFERRAL which can issue work orders for power quality, non-outage, issues reported by AMI meters. A new AOC cross-team business process has been developed with PacifiCorp's metering department for these work orders and field confirmation of issues. Figure 13 is a graphical representation of this process.

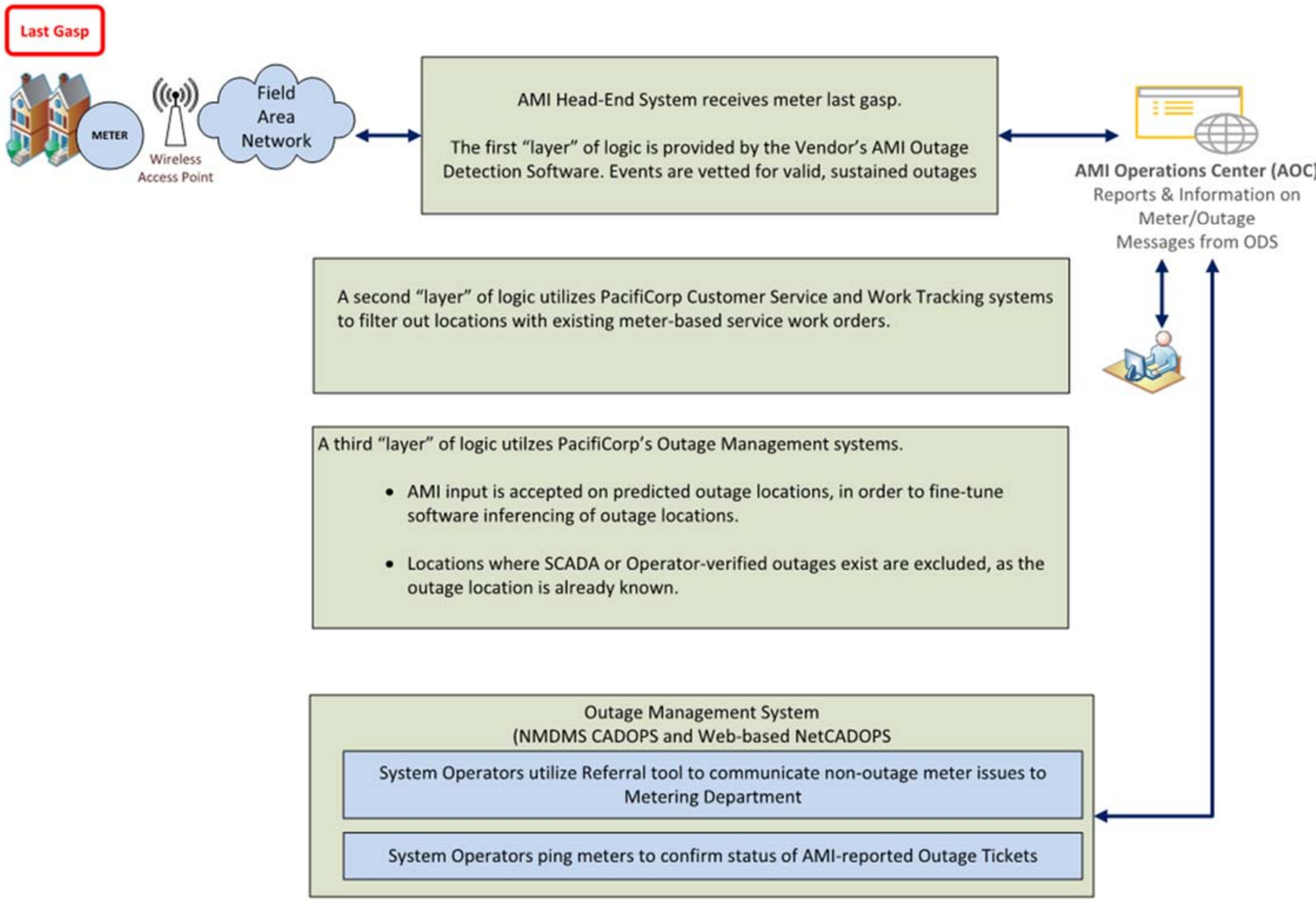


Figure 13 – Outage Detection and REFERRAL System

c) AMI Late-Night Awareness

The ability to ping individual meters from the outage management system was implemented in 2017. In combination with the AMI last gasps implemented in 2018, these tools are extremely useful for situational awareness. Two areas where distribution system operators note efficiencies are on feeders that have limited SCADA communications and late-night outage tickets where limited customer call information is available.

d) AMI Storm Assistance

System operators and support staff heavily utilized AMI meter pinging functionality during a recent large scale winter storm outage event in PacifiCorp's Roseburg district. Pinging proved critical to restoration efforts by allowing system operators to complete and close out already restored calls while identifying locations to send crews resulting in fewer and more organized truck rolls.

E. Distribution Automation and Reliability

DA is a comprehensive term that includes fault location, isolation, and service restoration (FLISR). It uses substation relays, reclosing devices and CFCIs, strategically placed, to automate restoration. These systems enable PacifiCorp to remotely or automatically reconfigure the distribution network in response to an outage. The devices can either: communicate their status to a centralized system (DMS) or use a peer-to-peer system. A feeder level or enterprise-DMS can determine the fault location and then signal to open or close devices to restore the maximum number of customers in areas outside the faulted section. A peer-to-peer system can communicate among itself using field-level intelligence. It determines the optimal switching strategy to restore customers. In a peer to peer system field device controllers determine the switching as opposed to a centralized DMS. A peer to peer system is utilized for power quality purposes to seamlessly switch between power sources at the Salt Lake City Airport. The pilot FLISR project in Lincoln City, OR will use a feeder level DMS controller. Either can be centrally operated by PacifiCorp system operators.

In order to make the most efficient reliability decision, PacifiCorp evaluates cost effectiveness for each area where reliability performance is not meeting local expectations. As these areas are evaluated, a determination is made whether local improvements should incorporate elements of a pilot that would be consistent with Smart Grid or Grid Modernization goals. Over the last four years, certain areas have resulted in advancement of projects consistent with smart grid concepts.

The Commission and PacifiCorp track reliability using certain standard metrics in the determination of the effectiveness and efficiency in the operation, maintenance, and repair of the distribution system. PacifiCorp is cautious about potential unforeseen consequences caused by overly broad incorporation of smart grid goals and projects into the company's distribution system on these metrics, i.e. cost per customer minute interrupted for reliability improvement targets. While PacifiCorp believes that reliability and security will improve customer experiences, the potential changes to how reliability is measured are unknown.

1. Distribution Automation

PacifiCorp continues to analyze the integration of DA and AMI networks. PacifiCorp is currently evaluating different DA strategies to help determine which method is the best fit for a typical distribution system based on cost, cybersecurity and scope of the DA effort.

Pilot Project Description

PacifiCorp is in the process of deploying a pilot DA FLISR scheme to improve system reliability in the distribution loop out of Devil's Lake substation in Lincoln City, Oregon. PacifiCorp is establishing a pre-deployment lab environment to create an open discussion across internal end-users including operations, service crews, and technicians. The DA scheme will use existing AMI access points deployed in Lincoln City. To improve service to this area, the DA system will automatically reconfigure the network with a substation based real-time automation controller which operates nine reclosers on two 20 kV distribution feeders. The DA system will respond to outage with the goal of reducing the duration of customer outages. PacifiCorp used a December 17, 2018 Lincoln City outage as a case study to estimate customer outage improvement after system deployment. Table 2 and Figure 14 shows a step by step explanation of the improvement. Figure 15 shows the December 17th outage overlaid on a distribution circuit map.

Table 4 - Predicted DA Reliability Improvement - Lincoln City

Restoration Scenario	Step	Time Stamp	Outage (min)	Cust. Out (#)	Cust. Restore (#)	(CMI)	Restoration Activity
Actual Event	1	12/17/18 11:53 PM	0.00				Tree hits mainline with sub CB lockout.
Actual Event	2	12/18/18 12:27 AM	34.00	4384	978	149,056	Wireman opened 4A376 switch. Sub re-energize to 4A376.
Actual Event	3	12/18/18 12:42 AM	15.00	3406	3252	51,090	Wireman opens 4A437 switch and closes 4A320 tie. Critical hopspital load restored.
Actual Event	4	12/18/18 2:54 PM	852.00		154	131,208	Crews remove tree, rebuild, and re-energize between 4A376 and 4A437.
					Total	331,354	

Restoration Scenario	Step	Time Stamp	Outage (min)	Cust. Out (#)	Cust. Restore (#)	(CMI)	Restoration Activity
DA Estimate	1	12/17/18 11:53 PM					Tree hits mainline with sub CB lockout
DA Estimate	2	12/17/18 11:53 PM	0.03	4384	4384	0	Automatic fault location, isolation, and restoration
DA Estimate	3	12/18/18 2:54 PM	900.97		154	138,749	Crews remove tree, rebuild, and re-energize between 4A376 and 4A437.
					Total	138,749	

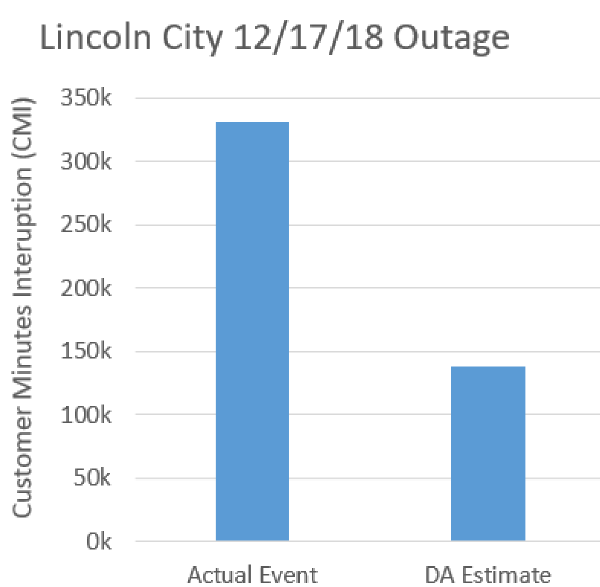


Figure 14 - Predicted DA Reliability Improvement - Lincoln City

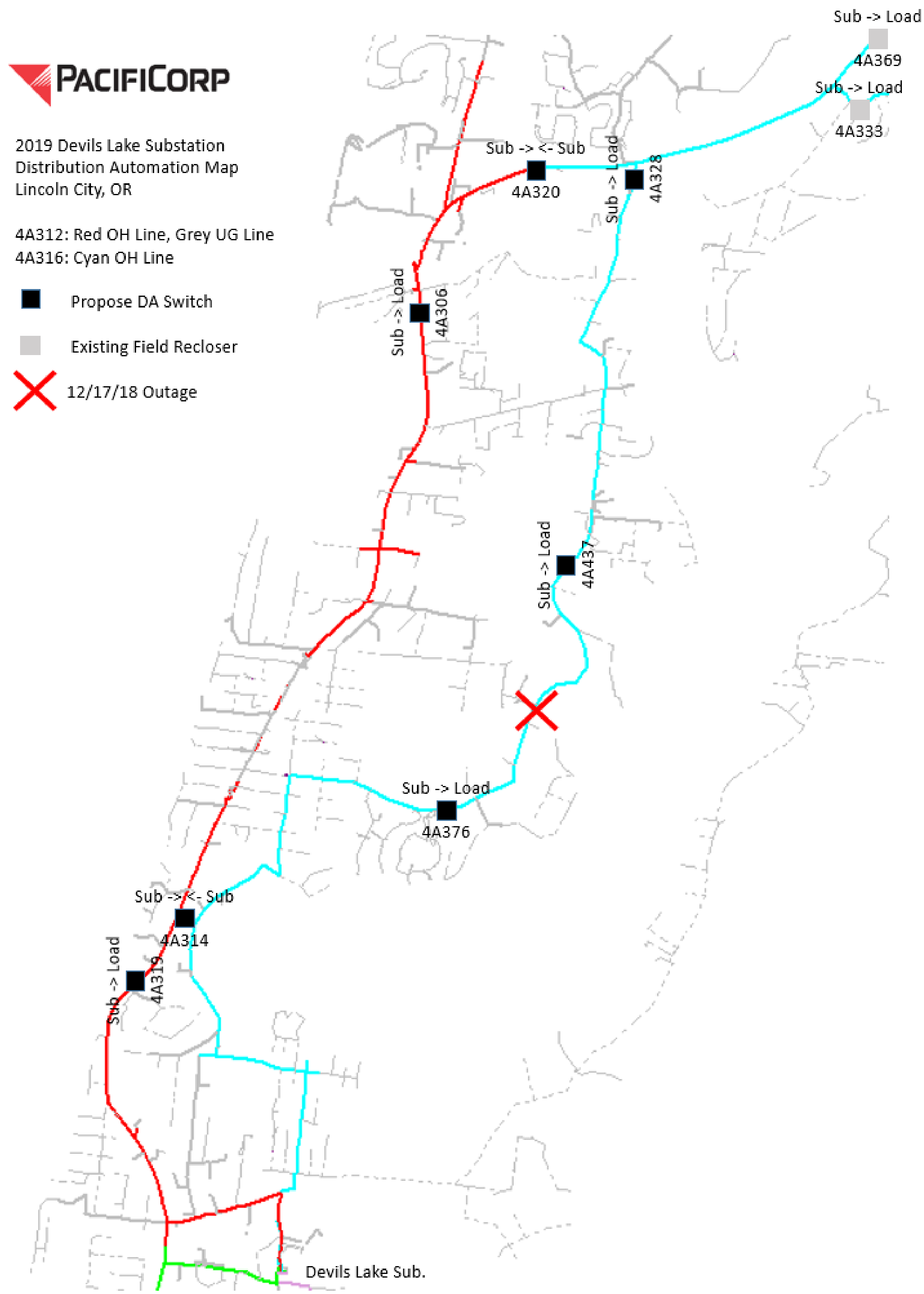


Figure 15 – DA Map – Lincoln City

Future Action

PacifiCorp plans to implement the Devil's Lake project in Lincoln City, Oregon by the fall of 2019. The success in its operability, integration into operations' practice, reliability improvement and associated costs will inform the decision to improve upon and implement future DA deployment. The company has started a lab hardware mockup utilizing the Lincoln City DA equipment that will be deployed. The lab is to aid in technology adoption and product development across engineers, technicians, service crews, and dispatchers.

2. <u>VaultGard Portland Low Voltage Secondary Network Project</u>

Project Summary

In the first quarter of 2019 PacifiCorp installed a network monitoring system on the downtown Portland portion of the underground distribution system fed from Lincoln and Albina substations, see Figure 16.

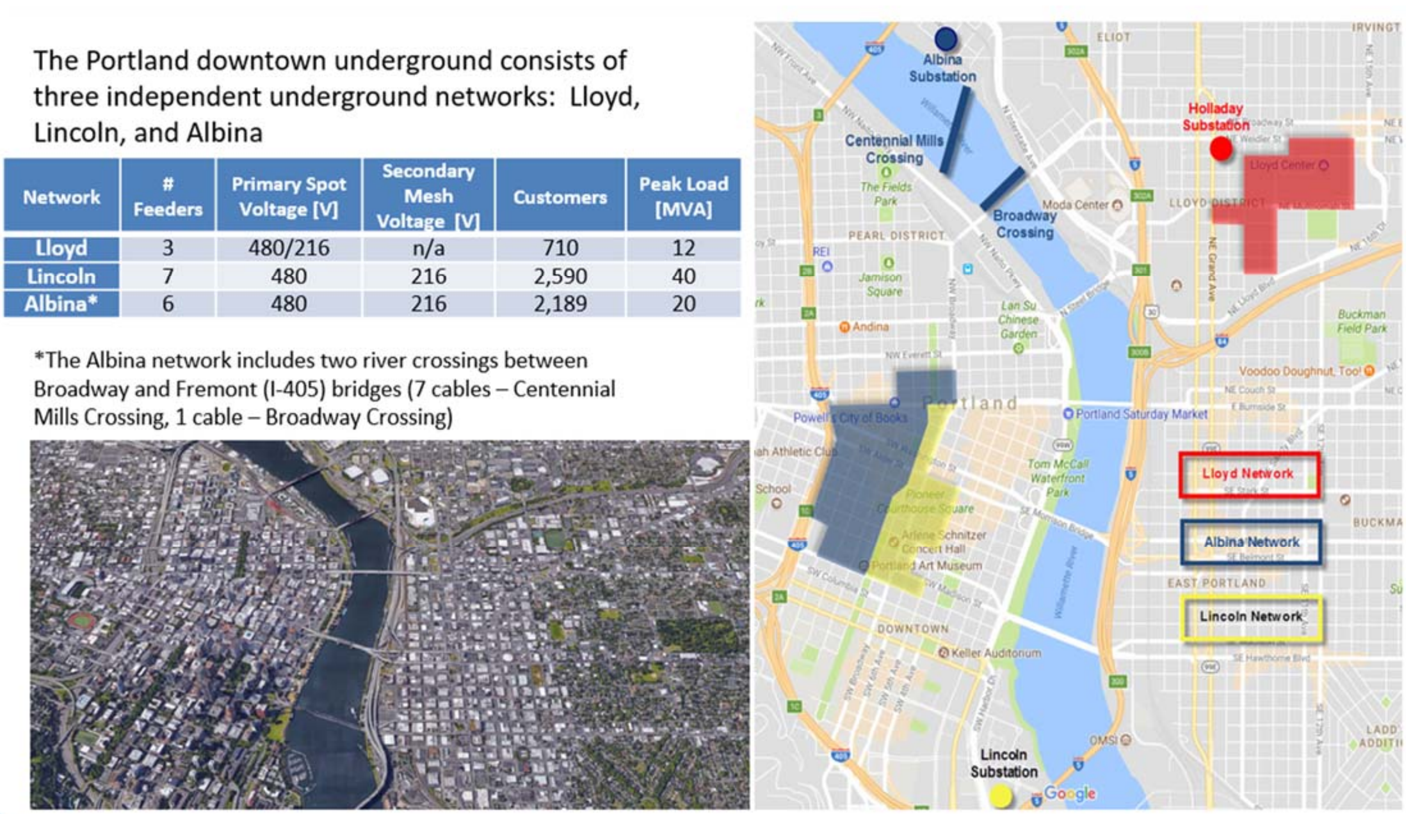


Figure 16 – Portland Underground Network Description

The scope of work was to install remote monitoring equipment in 76 vaults located within roughly 70 blocks of downtown Portland, from SW 5th Avenue to SW 13th Avenue and from NW Davis Street to SW Jefferson Street.

The communication design consists of installing two Real Time Automation Controllers at Lincoln Substation and utilizing distributed network protocol over a communication fiber ring to transmit the data from the network monitoring device back to the substation. From the substation the data would then be transferred and displayed on EMS for dispatchers and system operators. The network monitoring device receives all data from the network protector relay that is installed on the secondary side of the transformer. This relay is the "brains" and controller for the network protector operation and protection.

The downtown Portland Low Voltage Secondary Network (LVSN) is composed of 277/480V spot and 125/216V grid network systems. The lack of real-time monitoring left PacifiCorp vulnerable to equipment damage as many of the components are aging including primary switches, transformers, network protectors, and primary/secondary cables. This increases the risk of equipment operating incorrectly and creates the potential for abnormalities in the system to occur. Previously, there was no SCADA or other remote means of real-time monitoring to verify the operational status and loading data of the network equipment other than by bi-annual vault inspections or if an outage occurred. Table 5 compares predicted 2017 benefits to actual installed benefits.

Table 5 - Predicted vs Installed LVSN Monitoring Benefits

Predicted Benefit	Installed Benefit
Improved safety for the underground crews with less vault inspections	Ongoing Evaluation
Improved safety for underground crews with remote power disconnect before vault entry	Yes
Improved control capability	Yes
Ability to identify system deficiencies	Yes
Detect under/over voltages	Yes
Real-Time Monitoring to identify equipment abnormalities	Yes

Operation and Communication

The network monitoring device provides remote operation, communication, and monitoring capabilities to produce improved awareness on the LVSN. This awareness is used to support any future LVSN reconfiguration for existing load or new load, system operation, and power quality issues which can cause end-user equipment damage and service complaints.

Monitoring capabilities of the network monitoring device allow for improved system operation and restoration. An example of improved system operation would be when an N-2 or greater contingency occurs on the LVSN, the loading on the system increases significantly and overloading of equipment occurs which can result in damage or failure of the equipment. In this scenario the network monitoring device allows PacifiCorp to examine the system loading to determine if the network system needs to be de-energized to prevent damage or failure of the equipment.

Status of the network protector (open or closed) is also an important monitoring capability of the network monitoring device. This indication is useful when a black start restoration of the network system is required since it allows PacifiCorp to determine which protectors need to be opened or closed. Additionally, when a circuit breaker on the network system opens all network protectors on the feeder should open automatically. If one protector does not open this would indicate a mechanical issue or relay settings issue that should be fixed to prevent misoperation in the future.

Remote operation capabilities are used for maintenance of equipment installed on the network system. These capabilities include remote open block open, Protective Remote Close (PRC), and Adjustment of protector relay settings.

Network Protector

Each network protector actively monitors the direction of power flow to protect the system from fault events. All network protector operations determine power flow direction with a voltage phasor when open or current phasor when closed. The protectors open if real power is detected flowing out (reverse) of the network independent of reactive power, see an example phasor plot in Figure 17. A traditional system protection scheme is not possible given the variable input flow of a multi-source network.

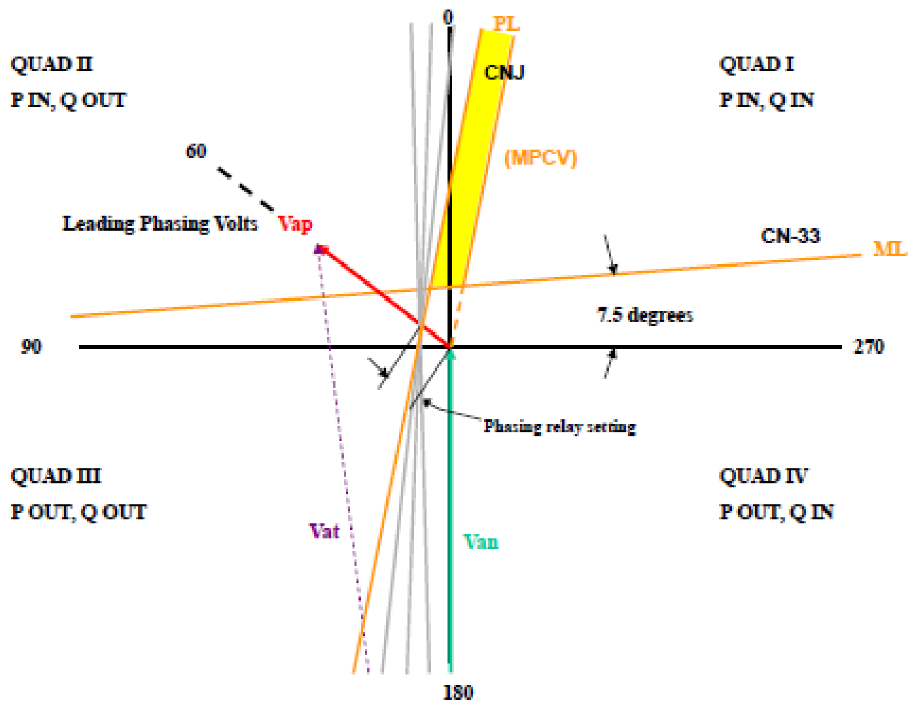


Figure 17 – Phasor Plot of LVSN Protector Relay Close Criteria[12]

Future Action

Over the next five years it is expected that the detailed secondary system model will be created. Many of the necessary system details do not yet exist in the GIS, which necessitates careful manual entry. Secondary networks systems are very complex and cannot be studied effectively without a high level of model accuracy. A comprehensive CYME model will facilitate better secondary network planning and alternative comparisons, and help with troubleshooting system anomalies such as outages and equipment overloads.

F. Demand Response

1. Recent Demand Response (DR) Developments

The *PacifiCorp Conservation Potential Assessment for 2019–2038*[13] (CPA), performed by Applied Energy Group, investigated the potential for, and cost of, summer- and winter-focused demand response (DR) options. PacifiCorp determines the need for new demand response through its CPA. The Northwest Power and Conservation Council defines demand response as a non-persistent intentional change

[12] Referenced from Eaton's "MPCV Relay Theory and Operation Fundamentals" literature.
[13] The full study is available on PacifiCorp's website. See Volume 3 for demand response inputs, methodology and results. http://www.pacificorp.com/es/dsm.html.

in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating parties.[14] The results of the CPA are used to evaluate demand response resources against supply-side alternatives in PacifiCorp's IRP. The 10 DR options that were included for analysis (listed below) represent the most cost-effective options for PacifiCorp's system. The results of the CPA are incorporated into IRP modeling, which evaluates the DR resources (along with other DSM) against supply side alternatives.

The following demand response options were analyzed in the 2019 CPA:

- Central Air Conditioners*[15]
- Domestic Hot Water Heaters*
- Space Heating*
- Smart Thermostats*
- Smart Appliances*
- Room Air Conditioners*
- Irrigation Load Control*
- Ice Energy Storage
- Curtailable Agreements
- Electric Vehicle Smart Chargers*

The 2017 IRP identified increased need for demand response, but the need occurred later in the planning period, with the first new demand response resources selected in 2028, as compared to 2022 in the 2015 IRP. More DR information will be available once the 2019 preferred portfolio is available.

2. Irrigation Load Control

Project Summary

On May 3, 2016, the Commission approved PacifiCorp's request to implement a pilot irrigation load control program for customers within the Oregon portion of the Klamath Basin. The Irrigation Load Control Pilot Program was filed to test the design characteristics of the company's existing irrigation load control program for its Oregon customers.

[14] https://www.nwcouncil.org/energy/energy-advisory-committees/demand-response-advisory-committee.
[15] * denotes Direct Load Control (DLC).

In 2018, the same group of customers participated as in 2017. The existing EnerNOC provided switches were replaced with Connected Energy-provided switches as part of the transition to the new delivery provider. Efforts were made to enroll the one customer with medium voltage equipment that was identified but not enabled during the prior seasons. Four events were called in August of 2018: three three-hour events and one four-hour event for a total of 13 event hours.

Customer Communication

Grower interest and engagement was maintained between the second and third year of the pilot and through the transition to the new load control provider. The small number of initial participants remain engaged and willing to participate in 2018 even when being asked to sign replacement participation agreements and have replacement switches installed on their equipment. The 2018 program year included four events. Three events were called in one week, which provides additional insight into the propensity for growers to opt-out of events. The growers participated in all events and fulfilled their commitment to curtail irrigation usage. Similar to the 2017 season, participants did not indicate concerns about water availability for the current season.

Future Action

On March 29, 2019, PacifiCorp submitted its annual compliance filing[16] in Advice 16-04 and recommended expanding and increasing the irrigation load control program for various reasons including its potential to defer traditional investments in substation upgrades, realize greater economic value in the energy markets, and maintain the flexibility to respond to any future demand response legislation.

PacifiCorp received four proposals for delivering the Irrigation Load Control Pilot Program. Two proposals did not meet the minimum technical requirements. The first proposal failed to pass the technical requirements and was for equipment only, and program delivery services were not included. The second proposal failed the technical requirements and indicated a lack of current irrigation load management delivery capability. Two proposals passed the technical screening, including the Connected Energy proposal which was selected by PacifiCorp. Connected Energy's proposal was the least cost option of the two that passed. The future of the load control programs was provided under the heading Post Year Three Recommendation in the 2018 Irrigation Load Control Pilot Program filed on March 29, 2019, under Advice 16-04. Information on three other irrigation load control programs is provided in Appendix H. The information in Appendix H is specific to irrigation customers and focuses on selected programs within PacifiCorp's territory in Idaho and Utah.

[16] https://apps.puc.state.or.us/edockets/docket.asp?DocketID=20031

On July 22, 2019, PacifiCorp filed Advice 19-008 that:

- Proposes to extend the pilot through the 2023 season,
- Expands the geography beyond the Klamath Basin to Central Oregon and south of Medford,
- Provides a higher incentive if customers can respond to hour ahead event notification (while still maintaining the current day ahead offer,
- Extends the season from August 15 to September 1,
- Extends the last hour for events from 8 p.m. to 10 p.m., and
- Enables events to be called on all days during the season (not just weekdays).

G. Distributed and Renewable Resource Enhancements

1. Transportation Electrification

In accordance with Senate Bill (SB) 1547, PacifiCorp filed its initial transportation electrification applications on December 27, 2016, proposing three pilot programs anticipated to accelerate transportation electrification in PacifiCorp's Oregon service territory. In February 2017, Commission staff requested additional information to expedite the review process. In response, PacifiCorp filed a supplemental application on April 12, 2017. On May 31, 2017, PacifiCorp hosted a settlement conference where intervening parties expressed support for, concerns with, and suggestions for improvement of various aspects of PacifiCorp's proposed pilot programs. This resulted in a stipulation that was filed on August 11, 2017, that resolved all matters in the proceeding (Stipulation). All but one intervening party agreed to the terms of the Stipulation. The Commission modified, adopted, and approved the Stipulation on February 27, 2018.

The lengthy proceeding resulted in the stipulation and order naming specific dates that did not align with the proposed three-year period of implementation. To align timing expectations, PacifiCorp filed a Motion to Amend Order No. 18-075 on February 25, 2019. On March 14, 2019, the Commission amended the order to modify the dates included in the Stipulation. The amended language also modified the Stipulation to require progress updates to the Commission by March 31, 2019, and March 31, 2020, with a report on pilot activities due by June 30, 2021.

PacifiCorp's electric vehicles (EV) brochure recommends off-peak charging and is a step towards pricing electricity based on time value (see Appendix E). For residential customers, an online electric cost calculator is available and provides information about off-peak EV charging, helping customers to understand when it is advantageous to charge their vehicle. PacifiCorp has created two EV residential electric pricing options.

See Appendix G for the more details on PacifiCorp's Transportation Electrification Pilot Update submitted to the Commission March 27, 2019. Since the March filing, additional progress has been made on the programs.

Public Charging Pilot

The construction timeline has been adjusted. Table 1 of Appendix G is updated as follows:

Location	**Estimated Construction Start**
Madras	Q3 2019
Otis	Q3 2019
Bend	Q3/Q4 2019
Mill City	Q1 2020
Klamath Falls	Q2 2020

Education and Outreach Pilot

The online cost comparison tool, WattPlan went live on PacifiCorp's website in the second quarter of 2019. Two ride and drive events were held in Oregon with at least two more planned for 2019. Technical assistance is now available to nonresidential customers and 11 customers have enrolled in the program.

Demonstration and Development

Twenty five grant recipients have been awarded up to $709,226 in grant funding. If all projects are completed they will add an additional 90 charging ports for drivers to use across the state.

2. Net Metering

PacifiCorp monitors customer generation and net metering customers throughout its service territory in an effort to ensure participation figures and generation capacities correspond with projected trends. PacifiCorp saw sustained annual net metering enrollment in 2018 sustained across its service territory. A monthly net metering and customer generation report for December 2018 is provided in Appendix A.

3. Centralized Renewable Resources

Numerous 10 MW solar generation facilities are now online in PacifiCorp service territory. The generation is connected to distribution substations by overhead and underground primary mainline. Reverse power flow occurs through distribution transformers. For instance, three 10 MW systems connected at the Pilot Butte Substation cause reverse power flow; load tap settings have been adjusted to accommodate. Restricted load tap changer settings can cause need for additional field regulation. Such frequent modifications and tuning of the system are expected to be part of standard operations as PacifiCorp adopts more Smart Grid technologies.

4. Distributed Energy Resources (DER) Deployment

PacifiCorp recognizes the role that DERs may play in the deferral or offset of traditional poles-and-wires infrastructure investments. DER is defined by the Commission Staff to include:

- Distributed generation resources,
- Distributed energy storage,
- Demand response,
- Energy efficiency, and
- Electric vehicles

As mentioned in prior smart grid reports, PacifiCorp deployed a DER screening tool for transmission and distribution planners to utilize in comparing alternative DER solutions to traditional solutions. The tool screens for solar, energy storage and demand-side management.

Project Description and Analysis

A DER alternative evaluation tool was created that, given a few input parameters common to traditional solution analysis, provides a feasibility assessment and cost comparison for solar, battery storage, and demand response solutions. The screening tool utilizes input parameters such as hourly facility load data, annual solar data obtained from National Renewable Energy Laboratory's (NREL) PVWatts Calculator[17] and cost estimates for battery storage and demand response solutions. The User Guide for the tool used to calculate projects and summarizes how the evaluation tool is used is attached as Appendix I. Costs in the alternatives template for solar installations are based on the results of recent PacifiCorp requests for proposal. Costs for battery storage were updated in November 2017 in the screening tool based on

[17] NREL. *PVWatts Calculator*. [Online]. Available: http://pvwatts.nrel.gov/.

studies performed by an external contractor to inform the IRP process[18]. The battery storage costs can be located in table 5.4, page 62, of the 2017 IRP update. The 2019 IRP (not yet released) will be supported with updated energy storage costs from a new energy storage study procured in 2018[19]. On an annual basis as part of the 10-year capital planning process, PacifiCorp identifies distribution feeders, distribution substations and local transmission lines with anticipated thermal or voltage constraints driven by load growth and recent load additions. For each of these constrained transmission and distribution facilities, the costs and benefits of facility upgrades such as replacement of equipment or increasing wire size are evaluated against the costs and benefits of various non-wires solutions including demand side management, energy storage and solar generation.

Pilot Targeted Energy Efficiency Projects

PacifiCorp has identified two potential locations through its DER alternative evaluation tool where alternative solutions may provide a cost effective means to defer the traditional capital investment solution to a substation or feeder capacity deficiency. In 2017, based on the results of the 2017 DER alternative evaluation tool review, PacifiCorp collaborated with the Energy Trust of Oregon (ETO) to implement a targeted load management pilot in the North Santiam Canyon. The goal of that pilot was to test the quick deployment of energy efficiency in a targeted area. The implementation phase of the pilot began in June of 2017, and continued through December 2018. The pilot resulted in 174 efficiency projects and 3,554 MWh saved.

In 2018, based on the results of the 2018 DER alternative evaluation tool review, PacifiCorp and ETO began designing a second targeted load management pilot in the Medford area. This pilot will build off the learnings of the North Santiam Canyon pilot and test new initiatives such as the need to align measures to resource peak and tracking marketing efforts. Specifically, the pilot aims to test the flexibility of Energy Trust's energy efficiency and solar program offerings and delivery strategies, and the efficacy of additional tactics to achieve demand reduction objectives. One example is integrating and promoting pilot measures that have the potential to achieve greater peak savings and provide increased incentives up to the maximum incentive allowed under current avoided costs to achieve pilot goals. The implementation phase of the pilot begins June 1, 2019, and will continue through December 2020.

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[18] The November 2017 report containing the battery storage costs developed for the IRP can be found at ***http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017%20IRP%20Update/2017_IRP_Update.pdf***.

[19] The 2018 energy storage study developed for the IRP can be found at ***http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Renewable_Resources_Assessment_for_the_2019_Integrated_Resource_Plan.pdf***

Future Action

PacifiCorp reviews proposed projects through the DER alternative evaluation tool. This activity typically occurs in the second quarter of each calendar year. Where feasible and cost-effective, DER solutions are expected to support and/or supplant traditional solutions for implementation.

H. Interconnection Standards and Smart Inverters

Inverters with advanced functionalities, referred to as smart inverters, allow for conversion of DC to AC for grid connectivity, as well as providing advanced capabilities to support the stability, reliability and efficiency of the electric grid. Such capabilities are imperative with penetration levels of inverter-based DER projected to increase through 2040[20] and necessitate standards be identified and followed to ensure a unified system.

PacifiCorp's interconnection standards and policies are based on the following standards, as well as other national, state and local jurisdictional guidelines:

- IEEE 1547 – *Standard for Interconnecting Distributed Resources with Electric Power Systems*[21]
- UL 1741 – *Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources*[22]

Background of IEEE 1547

The IEEE 1547 (2003) *Standard for Interconnecting Distributed Resources with Electric Power Systems* is a family of standards that serve as the collective interconnection standard for DER and address the technical and test requirements for systems less than 10 MW. The IEEE 1547 standard was published in 2003 and focuses on the technical specifications for, and testing of, the interconnection. The standard also provides requirements relevant to the performance, operation, testing, safety considerations and maintenance of the interconnection. The requirements are universally needed for interconnection of distributed energy resources, including synchronous machines, induction machines and power inverters/converters, and will be sufficient for most installations. IEEE 1547 was established as the national standard for the interconnection of distributed energy resources by the Energy Policy Act of

[20] U.S. Energy Information Administration (2015). *Annual Energy Outlook* [Online]. Table A16 p A-31. Available: https://www.eia.gov/forecasts/aeo/pdf/tbla16.pdf.

[21] IEEE. *IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems*. [Online]. Available: https://standards.ieee.org/findstds/standard/1547-2018.html.

[22] Underwriters Laboratories. *UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources*. [Online]. Available: http://ulstandards.ul.com/standard/?id=1741_2.

2005. Adherence to, or use of, an IEEE standard is considered an industry best practice.

The IEEE 1547 interconnection suite contains requirements pertinent to interconnection, control, operation, intentional islanding and conducting impact studies of DER interactions with electric power systems. IEEE 1547 is comprised of the following standards:

- IEEE 1547 (2003 and 2014 Amendment 1) – *Standard for Interconnecting Distributed Resources with Electric Power Systems*
  - IEEE 1547.1 (2005 and 2015 Amendment 1) – *Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces*
  - IEEE 1547.2 (2008) – *Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems*
  - IEEE 1547.3 (2007) – *Guide for Monitoring Information Exchange, and Control of Distributed Resources with Electric Power Systems*
  - IEEE 1547.4 (2011) – *Guide for Design, Operation, and Integration of Distributed Resources Island Systems with Electric Power Systems*
  - IEEE 1547.6 (2011) – *Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks*
  - IEEE 1547.7 (2013) – *Guide to Conducting Distribution Impact Studies for Distributed Resource Interconnection*
  - IEEE P1547.8 – *Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE 1547-2003*

Amendment to IEEE 1547

In mid-2013, members of the IEEE 1547 standards community initiated a "fast-track" amendment to IEEE 1547, labeled IEEE 1547a. Published by the standards organization in May 2014, IEEE 1547a was a "permissive" update to IEEE 1547-2003 whose main purpose was to permit some functionalities not allowed in IEEE 1547-2003. The amendment later initiated a full revision of IEEE 1547 in consideration of evolving technology and functionalities of modern inverter-based distributed energy resource systems.

Company Participation

PacifiCorp was an active member of the IEEE 1547 standards working group and supported the standards' revision process. The revised IEEE 1547 standard is technology agnostic with the requirements focusing on functionality. Prescriptive updates to the standard, as to how to implement a solution to satisfy the requirement, have been omitted.

Several sections of IEEE 1547 have undergone significant changes including but not limited to voltage regulation, response to abnormal voltage and frequency conditions, islanding, power quality and interoperability. The main intent of these changes is to clearly define and understand the challenges of integrating smart inverters into the suite of interconnection standards. The changes address general technical specifications, performance categories and default equipment settings. The IEEE 1547-2018 standard was published in April 2018.

In September 2016, the Underwriters Laboratories (UL) 1741 working group published UL 1741 Supplement SA to define the evaluation criteria for utility-interactive inverters with grid support functionalities. The requirements provided in the revised standard are intended to validate compliance with grid interactive functions that are not covered in IEEE 1547-2003. These grid support functions may include, but are not limited to, voltage and frequency ride-through and active and reactive power control. A few inverter manufacturers have started to test and certify inverters to the new UL 1741 standard. The IEEE standards committee is working expeditiously towards revising IEEE 1547.1, which will provide testing requirements for the new IEEE 1547 standard. Coordination between the UL 1741 Supplement SA testing and certification requirements and the new IEEE 1547.1 testing requirements is currently in process.

Future Action

The UL 1741 Supplement SA is the updated version of the UL 1741 test standard. UL 1741 Supplement SA specifies the test methods needed to build the foundation for DER to stay online and adapt their output and overall behavior to stabilize the grid during abnormal operation rather than simply disconnecting. States like California and Hawaii have implemented UL 1741 Supplement SA and require inverters to be compliant with this standard, configured with their respective source requirement documents, such as Rule 21 and Rule 14H. PacifiCorp intends to implement the advanced inverter functionality recommendations defined in the IEEE 1547-2018 standard, however the company will wait for the market to release inverters compliant with the latest standard. Since the process and requirements to test inverters' compliance with the revised standards has not yet been finalized, currently there are no inverters available in the market that fully comply with IEEE 1547-2018.

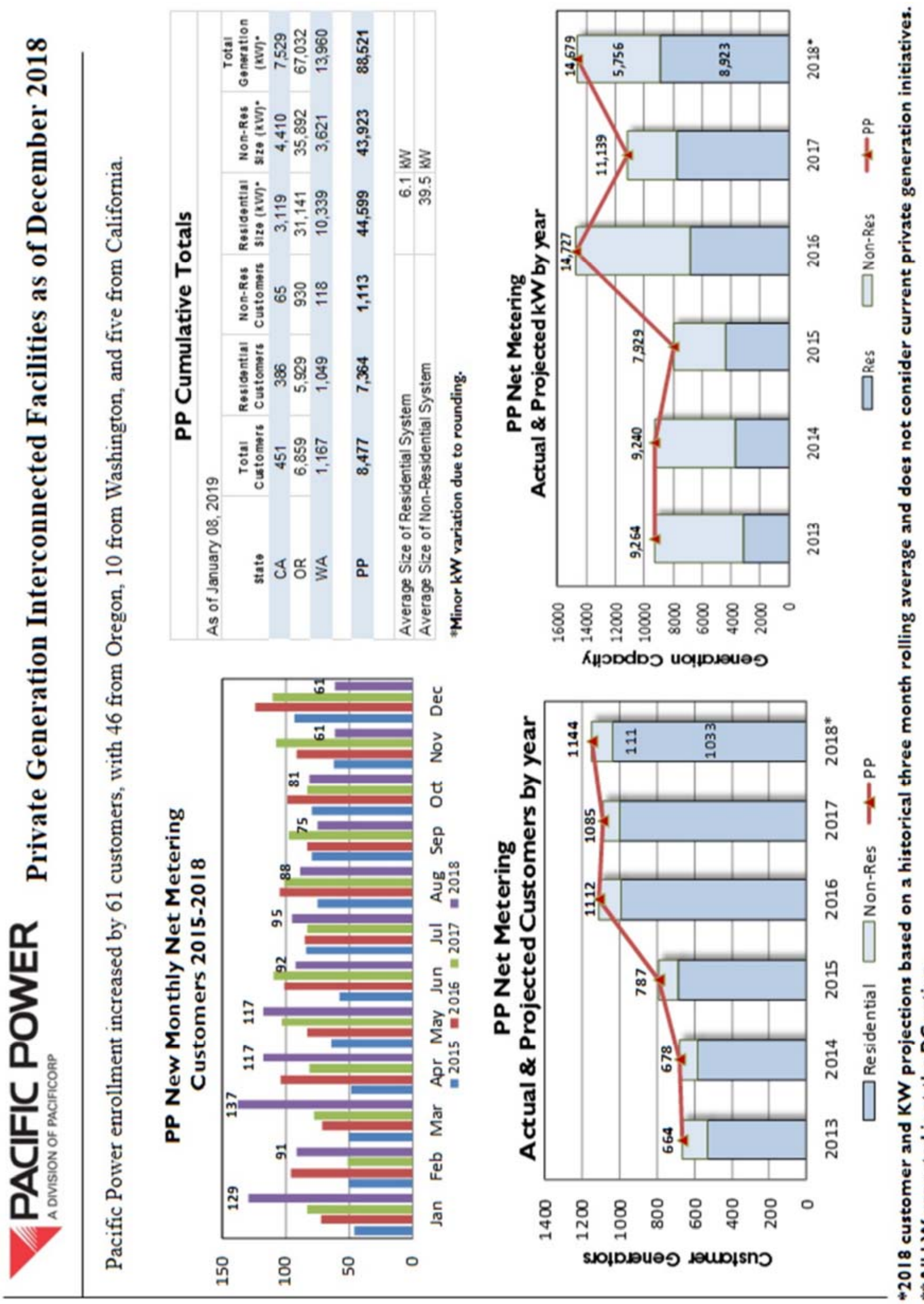
VI. Road Map to Grid Modernization

The development of an objective grid modernization road map must consider the economic value of individual components, technology maturity, and system interdependencies. Although funding levels will vary, PacifiCorp's 10-year capital plan provides for investment in the listed smart grid plans. In addition, funding is planned for smart grid technologies expected to be leveraged by the implementation of AMI, such as data analytics, outage management and DA.

VII. Conclusion

PacifiCorp continues to develop a strategy to attain long-term goals for grid modernization and smart grid-related activities to continually improve system efficiency, reliability and safety, while providing a cost-effective service to our customers. PacifiCorp will continue to monitor smart grid technologies and determine viability and applicability of implementation to the system.

Appendix A – PacifiCorp Net Metering and Customer Generation



State	Total Customers	Residential Customers	Non-Res Customers	Residential Size (kW)*	Non-Res Size (kW)*	Total Generation (kW)*
CA	451	386	65	3,119	4,410	7,529
OR	6,859	5,929	930	31,141	35,892	67,032
WA	1,167	1,049	118	10,339	3,621	13,960
PP	8,477	7,364	1,113	44,599	43,923	88,521
Average Size of Residential System				6.1 kW		
Average Size of Non-Residential System				39.5 kW		

Figure 18 – Private Generation Interconnected Facilities, as of December 2018

Appendix B – Union Gap Enhanced SCADA Project

The goal of the Union Gap distribution project was to reduce the time required to recover from system disturbances by providing useful and timely information to region operations.

The distribution feeder is the last system awareness device the operations center utilizes for understanding the integrity of the multi-phase and single-phase distribution power supply network. Presently, the intelligent relay equipment monitoring the outbound power source to customers provides very basic status and telemetry. Understanding the relay device has a greater potential of providing essential information, a pilot project was initiated to extract addition measurements and provide these values back into the control center for operational awareness.

The intent was to use existing collection and communication infrastructure within the substation to provide quantities from the relays directly to dispatch through SCADA system. The following quantities were selected:

- Faulted Phase indication
- Fault Magnitude available
- Distance to Fault
- Relay Targets (50, 51)
- 3-phase current analogs

T_IND	UNIONGAP	CB 5Y466 A PH FAULT		Normal
T_IND	UNIONGAP	CB 5Y466 B PH FAULT		Normal
T_IND	UNIONGAP	CB 5Y466 C PH FAULT		Normal
T_IND	UNIONGAP	CB 5Y466 INST OC FAULT		Normal
T_IND	UNIONGAP	CB 5Y466 TIME OC FAULT		Normal
T_I&C	UNIONGAP	CB 5Y466 FAULT RESET		Off

Figure 19 – Union Gap Fault Status Data for Circuit Breaker 5Y466

T_IND	UNIONGAP	CB 5Y466 A PH FAULT		Normal
T_IND	UNIONGAP	CB 5Y466 B PH FAULT		Normal
T_IND	UNIONGAP	CB 5Y466 C PH FAULT		Normal
T_IND	UNIONGAP	CB 5Y466 INST OC FAULT		Normal
T_IND	UNIONGAP	CB 5Y466 TIME OC FAULT		Normal
T_I&C	UNIONGAP	CB 5Y466 FAULT RESET		Off

Figure 20 – Union Gap Fault Analog Data for Circuit Breaker 5Y466

These quantities were in addition to those already being brought into SCADA and would be provided from all Union Gap devices capable of transferring this data. With the understanding the protective relays already were installed in the control house, the scoping focused on any additional communication configurations, relay programming and master SCADA database/display configurations which would be required to deliver these values to dispatch.

The work effort was integral of the following departments perform their respective piece of the total effort:

- Substation engineering and design
- Relay technicians
- SCADA engineering
- SCADA database administration
- SCADA data and di play commissioning system analysts

Each department would have a specific activity with a cost allocation. Time will determine the payback period of the required costs to implement increased situation data to the operations center.

Additionally, this phase fault data is under analysis to be transferred for the SCADA system to the outage management system to further enhance outage management.

The flowing displays highlights the increased system awareness that is now available at Union GAP in the SCADA system.

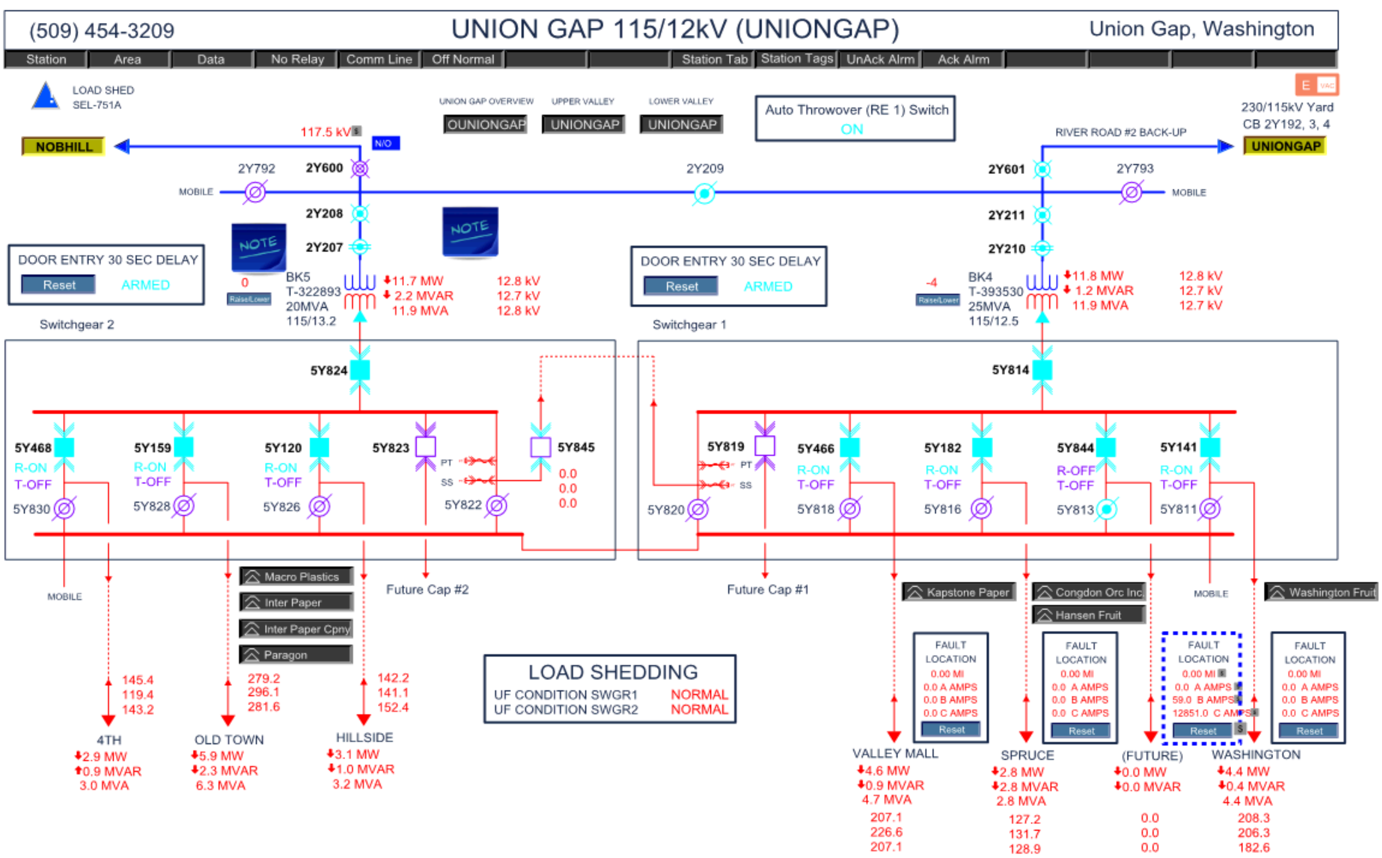


Figure 21 – Union Gap EMS SCADA Display

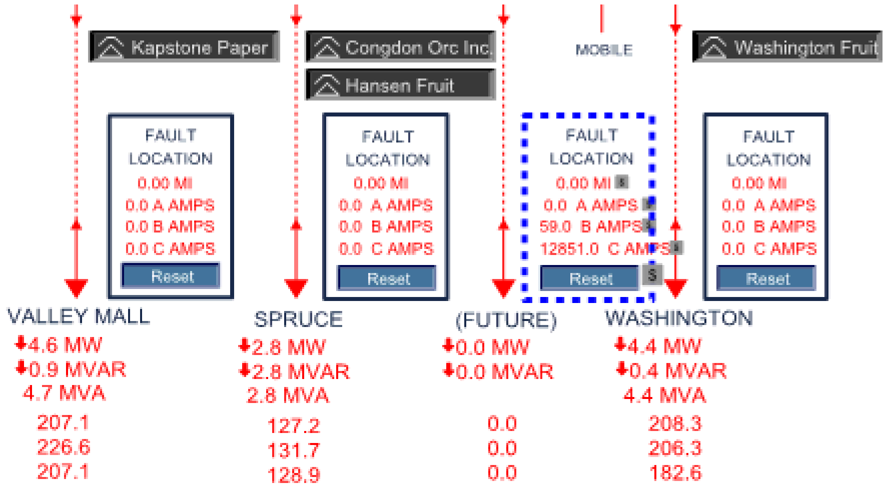


Figure 22 – Union Gap EMS SCADA Display - Expansion of Fault Data

The fault magnitude identifies the distance of the fault from the substation outbound with the phase information determining the geographical area when view on a network architecture map.

Upon a faulted line, Regional operations can efficiently determine the appropriate area in which to send the first responders for initial distribution fault troubleshooting. After studying the fault restoration activity, consideration would be given to incorporation of this valuable data into a standard design package for future distribution projects.

Appendix C – Tracking AMI Savings

Table 6 - Tracking AMI Savings

Description	Business Case Savings	Method	Status
Reduce the following operational costs: Meter Reading Collections Meter Managers Metermen Clerks	Savings will be realized through the automation of job functions and replacement of the majority of meters in Oregon.	Establish a baseline of employees who are on the payroll at the start of the project. Employee reductions will be reported against departures tied to the AMI deployment schedule.	As of mid-July 2019, there have been 104 employees leave the business on schedule, including temporary and part-time employees.
Reduce Overtime (Metering and T&D)	The ability to remotely connect service will eliminate the need to physically visit most meters after working hours to connect service.	SAP Mobility Workforce Management System After-hours connect trip volumes will be tracked as well as overtime hours. The numbers will be measured against pre-AMI costs.	Analysis of after-hour reconnection vehicle trips is underway in areas where remote connect functionality has been enabled. After-hour reconnects requiring truck rolls are down by 50% in 2019. In the Willamette Valley, Lincoln City, and Medford, the average number of after-hour connect/reconnect trips has gone from 16.5 to 1.8 per month. The estimated overtime reduction based on a two hour

Description	Business Case Savings	Method	Status
			call-out is approximately 176 hours, or $22,000 for the first six months of 2019 in these areas.
Avoided Handheld Maintenance and Repair	Meter reading handheld maintenance expense will decline as the number of handhelds decline.	Handheld maintenance expense is tracked in SAP. Post-AMI expense will be compared to pre-AMI expense.	Handhelds have been reduced by 50 units and projected to be 75 by the end of 2019. Annual maintenance for a handheld and docking station is $600 per year. Handheld maintenance reduction is $30k per year to date.

Description	Business Case Savings	Method	Status
Theft Reduction	Visiting each meter during the exchange process will enable the business to detect theft and stop it.	Establish a business process for the mass meter installer to alert utility of theft cases. Analysis will be performed to quantify value of loss.	Theft identified during the meter installation process is being tracked. Perform analysis of revenue protection work request volumes. Nineteen theft cases have been discovered to date.

Appendix C – Tracking AMI Savings

Description	Business Case Savings	Method	Status
Reduced Power Losses	The ability to disconnect service between tenants will reduce the amount of power loss.	Compare unbilled kWh between tenants post meter exchange to baseline data in the business case.	Work underway to quantify avoided loss in areas where installations are complete. In addition to disconnecting between customers, 4,451 sites without customers have been disconnected to prevent power loss.
Revenue from Added Meters with VARs	Establish VAR billing for all applicable customers.	Establish baseline data by extracting VAR billing data prior to meter exchanges. Compare post meter exchange values to determine incremental benefit.	Need to go through an irrigation season in order to quantify this benefit.
System Energy Loss Reductions	Mechanical meters require 24 watts of energy before they start and electronic meters require only 5 watts. Mechanical meters consume .70 watts of energy to operate compared to .46 watts for an electronic meter.	Perform lab testing to validate electronic meter performance in conjunction with industry and company findings.	Will quantify savings based on industry experience.

Appendix C – Tracking AMI Savings

Description	Business Case Savings	Method	Status
Revenue Recovery on Unaccounted for Energy	Electronic meters are more accurate than mechanical meters.	Perform lab testing to validate electronic meter performance in conjunction with industry and company findings.	Will quantify savings based on industry experience. External lab test information is expected to be available sometime in the second half of 2019 to determine improved accuracy and meter electricity use.
Reduction in Write-offs	Write-off expense will decline with the ability to perform collection disconnects sooner.	Write-offs are currently tracked as a percent of revenue. Collection order volumes are tracked in the Mobility Workforce Management System. Baseline data will compare the time to disconnect pre-AMI to post-AMI. Compare pre-AMI write off expense to post-AMI write off expense.	Write-off expense and collection volumes are currently tracked. It is too early to determine the impact on write-offs. However, analysis is underway on accounts receivables in areas where installations are complete. Write-offs normally occur 180 days after an account becomes inactive. Therefore, it is too early to determine the impact on write-offs. However, preliminary analysis for

Appendix C – Tracking AMI Savings

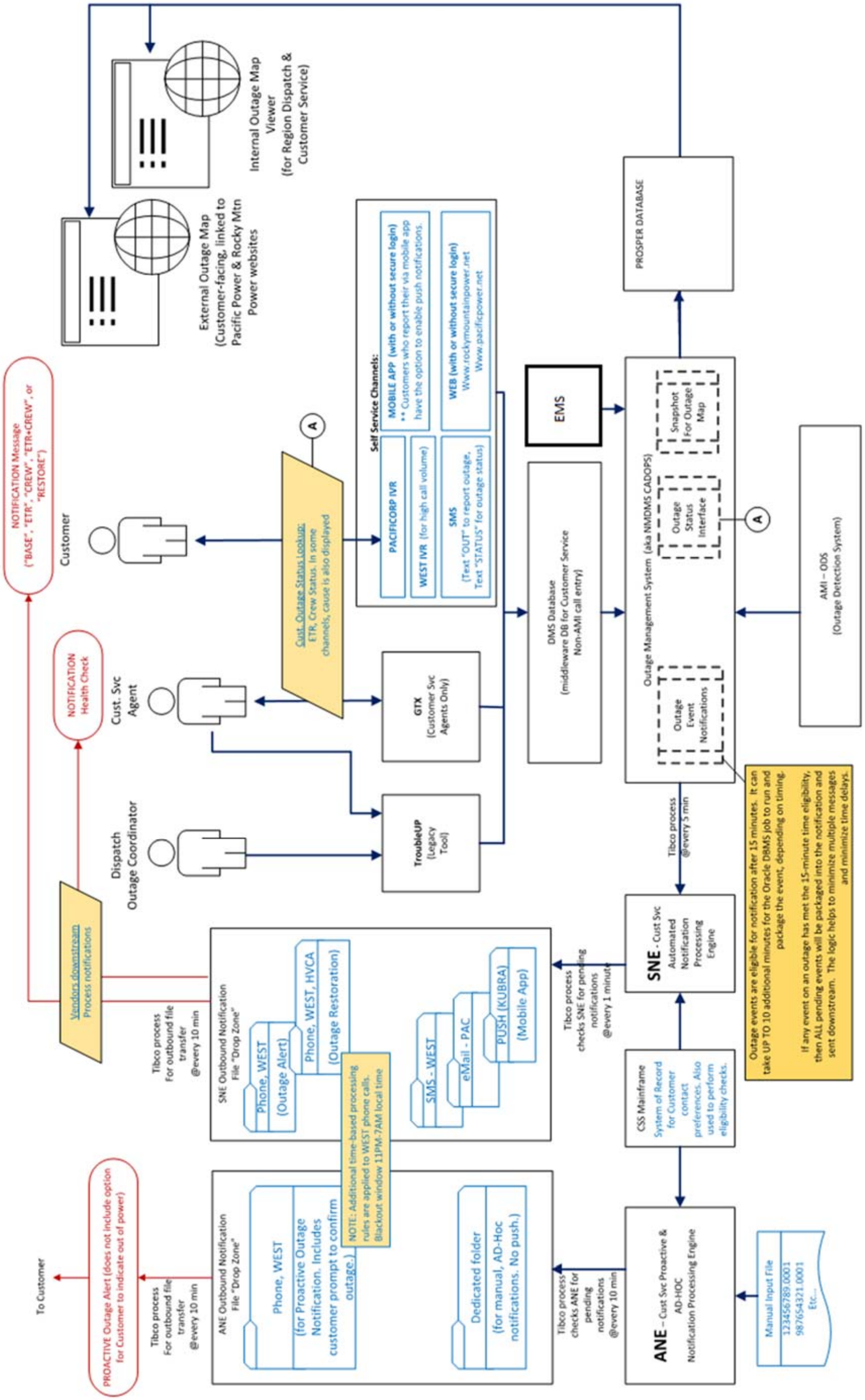
Description	Business Case Savings	Method	Status
			Willamette Valley, where installations were first completed, show a 30% drop in combined active and inactive arrears. Write-off data for areas already converted will be available in the fourth quarter of 2019 while post-smart meter install write-off analysis will occur sometime after the first quarter of 2020.
Avoided Meter Purchases	Replacing the majority of meters in Oregon will reduce meter failure rates thereby reducing the need to purchase replacement meters.	Meter purchase expense and volumes are tracked in SAP. Compare post-AMI purchase expense and volumes to pre-AMI purchase expense and volumes.	Meter purchases in 2020 will enable this benefit to be quantified.
Avoided Load Study Costs	Interval/register data provided via AMI eliminates the need to install unique meters/programs for load study purposes.	Historical data will be compared to post AMI data and quantified.	Analysis will be conducted using historical costs. Load studies will utilize interval data from installed smart meters. Residential

Appendix C – Tracking AMI Savings

Description	Business Case Savings	Method	Status
			smart meters will need to be remotely reprogrammed to change the recorded interval from hourly to 15 minutes at a cost of approximately $6 per meter. Actual cost using smart meters will be available with a load study scheduled in the first quarter of 2020.
Avoided Handheld Replacement Costs	Handheld replacement costs will decline as the number of employees decline.	Handheld replacement costs are tracked in SAP. Post-AMI replacement costs will be compared to pre-AMI costs.	Will be quantified in 2020.

Appendix D – Affected Customer Communication

Figure 23 – Affected Customer Communication



Appendix E – EV Brochure

Give yourself an energy boost by making the switch to an EV.

The benefits of driving electric:

- Cheaper to operate, fuel and maintain than gas-powered cars
- No more trips to the gas station
- No more oil changes
- No tailpipe emissions
- Less impact on the environment
- Quiet operation
- Fun to drive
- Get a federal tax credit of up to $7,500*

To further reduce your carbon footprint, enroll in our Blue Sky℠ renewable energy program.

Consult your tax advisor

Charging your EV.

While having an electric vehicle means you won't be relying on gasoline anymore, they still require charging. Here's what you need to know.

Types of chargers:

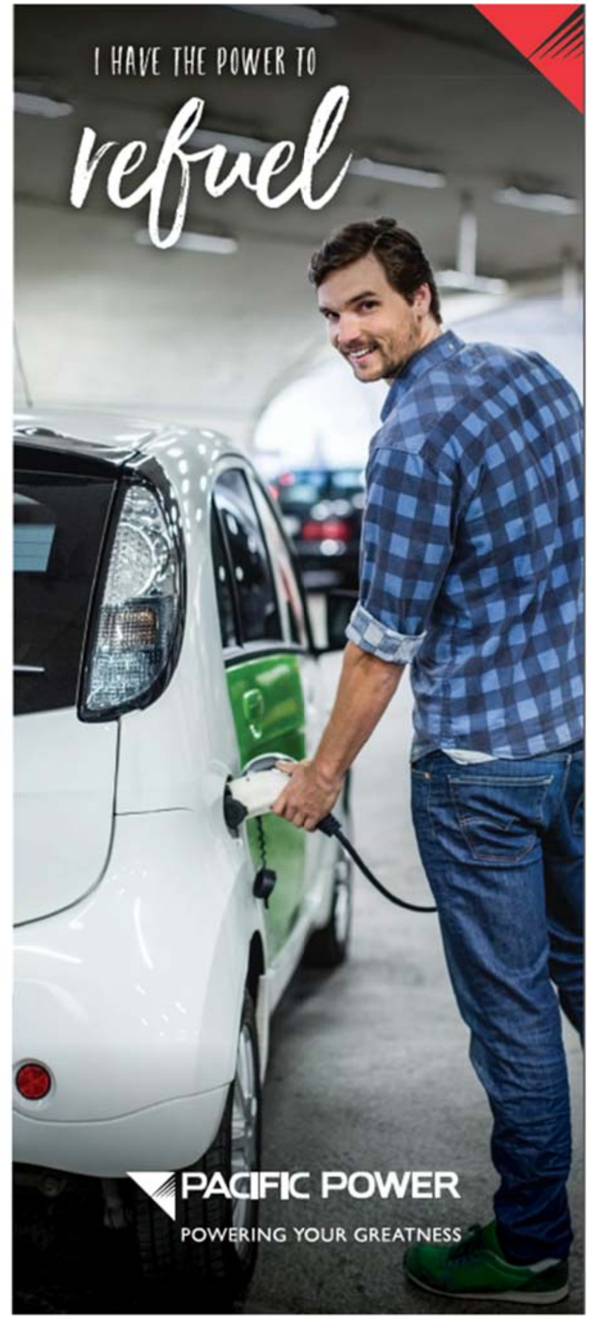
Basic
A typical household outlet (120v) provides a Level 1 charge, which takes about 8-15 hours.

Quicker
Level 2 (240v) charging takes about 3-6 hours for a full charge. Electrical upgrades may be necessary for Level 2 home charging.

Fast Charge
At shopping centers, restaurants and near highway exits throughout Oregon and the Northwest, DC fast chargers take about 20-40 minutes for a full charge.

It's best to charge your car at night and on weekends when there is less demand for electricity. You have the choice to enroll in our Time of Use program to take advantage of lower rates for charging during these off-peak hours.

PACIFIC POWER
POWERING YOUR GREATNESS



Appendix E – EV Brochure

Electric vehicles reduce emissions, improve air quality and advance innovative technology.

With Pacific Power programs and community partnerships, you will have more opportunities to get behind the wheel of an electric car and tools to determine if an EV is right for you.

Already driving an EV? You'll have more places to refuel along our highways, at workplaces and in our communities.

Electric vehicles can be cheaper to operate than gas-powered cars and help lower emissions.

You can fuel an electric vehicle for the equivalent of about **$1 per gallon*** of gasoline, which can make a big difference for your family budget. In many cases, electric vehicles cost less to maintain than gas-powered cars because they have fewer moving parts. You can wave goodbye to oil changes and the gas station.

Annual fuel, maintenance and operating details for select electric and conventional vehicles according to Kelley Blue Book:

VEHICLE	AVG ANNUAL FUEL COST	AVG ANNUAL MAINT. COST	AVG MILES PER GALLON (or equivalent)	COST PER MILE	BATTERY RANGE/ MILES PER CHARGE
2018 Chevrolet Bolt EV	$329	$433	119	$0.54	238 miles
2018 Nissan LEAF EV	$349	$387	112	$0.45	151 miles
2017 Ford Focus Electric EV	$380	$547	105	$0.48	115 miles
2017 Kia Soul EV	$389	$442	105	$0.50	93 miles
2017 Toyota Camry	$1,659	$512	25	$0.57	N/A
2017 Kia Optima	$1,473	$449	28	$0.49	N/A
2017 Mazda 6	$1,354	$438	30	$0.58	N/A
2017 Honda CR-V	$1,386	$431	29	$0.54	N/A

Source: KBB.com

To learn more about EV benefits and charging, visit **pacificpower.net/ev.**

*energy.gov eGallon; the eGallon represents the cost of driving an electric vehicle the same distance a gasoline-powered vehicle could travel on one gallon of gasoline.

Appendix F – 2018 Stakeholder Recommendations and Company Action

Table 7 - 2018 Stakeholder Recommendations and Company Action

Commission Recommendation Description	Company Action	Page
2. PacifiCorp should continue to update the AMI Roadmap using the stated tracking methods. The Company should also specify a method for tracking customer engagement. The Company should also develop a system by the next Smart Grid report to perform and report on the Impacts of financial modeling on AMI action prioritization and solution comparison among different applications.	AMI has been identified as a restoration tool in the OMS system. AMI capabilities are being explored including using real-time data for transformer loading and customer load profiles.	9-15, 31-33, Appendix C
3. The Company should provide updates and results of its expanded PMU installation project and provide additional information in future smart grid reports on the evaluation process used by the company in choosing deployment locations for the synchrophasors that will provide the data critical for compliance.	An update of installed PMUs locations and spotting criteria has been reported.	16-18
4. The Company should provide results from its 2017 RFP for load control services, and what projects, if any, were installed. The Company should provide its assessment of the pilot in regards to the future of the load control program.	A summary of the irrigation load control projected is provided. Details are available in the ADV 242 compliance filings.	42-44
5. PacifiCorp should update their progress of linking distributed devices to its OMS, EMS, DMS, and each other, if applicable, in its 2019 Smart Grid Report. The Company should also provide an overview of its adherence to the IEC 61968 standard.	Preliminary linking has occurred between OMS and EMS in the customer outage notification system. Some general elements of IEC 61968 were adopted in the implementation of the AMI IT architecture.	26-27
6. PacifiCorp should provide an update on any field area network or communication functionality implementation.	The field area network in Oregon has been completed.	27-30
7. PacifiCorp should continue to keep the Commission apprised of demand response developments in future smart grid reports and should track and update in its next report the market development for DR technology, customer demand for DR products and services, and assess the impact of DR on Smart Grid initiatives, including but not limited to renewables integration.	A summary of the irrigation load control projected is provided. Details are available in the ADV 242 compliance filings.	41-43

Commission Recommendation Description	Company Action	Page
8. PacifiCorp should summarize any projects screened using the DER tool where DER projects were found to be a cost effective alternative to traditional solutions, and describe any DER projects that were or will be installed due to positive results. In addition, the Company should share in its next report the evaluation of the eight separate values found in the Utility Applications and Value streams, how those values may stack, and more information on the modeling the Company is using to value energy storage and any impacts from this modeling on project evaluation.	The Company has identified two potential locations through its DER alternative evaluation tool where alternative solutions may provide a cost effective means to defer the traditional capital investment solution to a substation or feeder capacity deficiency. The DER tool is only a screening tool and not intended to be a final vetting of projects that may defer a T&D solution. Please refer to the Company energy storage docket for use cases of energy storage and potential of those use cases when stacked.	46-47
9. PacifiCorp should summarize its findings of its smart inverter analysis project, and what projects or infrastructure involving smart inverters, if any, have been initialized.	The Company continues to participate in the IEEE smart inverter standard development.	48-50
10. The Company should provide detail of the DA project in the Lincoln City area and any other deployments, as well as any results observed from project deployment.	The Company is in progress of deploying a pilot DA system and will evaluate performance and value. A pre-deployment lab environment is being established to create an open discussion on automated operation across dispatch, service crews, and technicians.	34-38
11. The Company should provide an update and results of the Portland network monitoring system installation, as well as plans for future deployment.	The monitoring system was placed in service Q1 2019. The report discusses system functionality and actual performance.	38-39

Table 8 – 2019 Informal Stakeholder Recommendations

Commission Recommendation Description	Page
IV. Projects Overview, Figure 3, p. 8: Break up the "Completed / In Progress" category so this image quickly identifies three separate levels of status: completed, in progress, and initiative under consideration.	8
V. Status of Grid Modernization and Smart Grid Investments, A. Advanced Metering Infrastructure, p. 9: Please include the percentage of customers who opted out.	11

Commission Recommendation Description	Page
V. Status of Grid Modernization and Smart Grid Investments, A. Advanced Metering Infrastructure 1. Functionalities, Remote connections/disconnections, p. 10: Elaborate under what circumstances PacifiCorp *can't* restore power while the customer center representative is still on the phone with the customer.	10
V. Status of Grid Modernization and Smart Grid Investments, A. Advanced Metering Infrastructure 1. Functionalities, Operational Efficiencies, p. 10: Provide more detail of the successful savings. • Explain what is blocking insight into AMI's impact "on outage management processes and reliability metrics."	10
V. Status of Grid Modernization and Smart Grid Investments, A. Advanced Metering Infrastructure 2. Customer Engagement, AMI Deployment Communication, p. 10: • Identify when and where the Independence, OR meeting will be held. • Detail Market Strategies' survey results.	11-12
V. Status of Grid Modernization and Smart Grid Investments, A. Advanced Metering Infrastructure 2. Customer Engagement, Proactive Tracking of AMI Remote Operation, p. 11: Please include how many times remote connect functionality has failed.	12
V. Status of Grid Modernization and Smart Grid Investments, A. Advanced Metering Infrastructure 3. Customer Centric Tools and AMI Features, Bill Projections, p. 12: Identify the percentage of customers who have entered a target dollar amount.	13
V. Status of Grid Modernization and Smart Grid Investments, B. Transmission Network and Operations Enhancements, 1. Transmission Situational Awareness, p. 14: Identify the outage time reduced by the Astoria pilot installation.	15, Footnote 5
V. Status of Grid Modernization and Smart Grid Investments, B. Transmission Network and Operations Enhancements, 2. NERC Reliability Standard MOD-033-1 and PRC-002-2, DFR/PMU Placement p. 16: Identify the percentage of locations at large generators of 75 MW or larger that have been upgraded.	17
V. Status of Grid Modernization and Smart Grid Investments, B. Transmission Network and Operations Enhancements, 2. NERC Reliability Standard MOD-033-1 and PRC-002-2, DFR/PMU Next Steps p. 16: Identify when data will be "delivered to a centralized Phasor Data Concentrator (PDC) storage server where offline analysis can be performed by transmission operators, planners, and protection engineers."	16-17
V. Status of Grid Modernization and Smart Grid Investments, B. Transmission Network and Operations Enhancements, 3. Energy Imbalance Market, p. 17:	N/A

Commission Recommendation Description	Page
• Identify the degree to which the Company's dispatch has become more efficient due to the EIM. • Identify the amount of the Company's renewable curtailment reduced by participation in the EIM. • Identify the amount of reduction in the Company's need of flexible reserves due to EIM participation. • Detail "the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the ISO to serve California load." • Detail any other market barriers the Company faces when transferring into the ISO to serve California load.	
V. Status of Grid Modernization and Smart Grid Investments, B. Transmission Network and Operations Enhancements, 4. Cybersecurity, Project Description, p. 19: • Identify the biggest challenge the Company faces staying in compliance with NISTIR 7628.Detail the results of the most recent audit. • Detail the results of the penetration testing.	19-20
V. Status of Grid Modernization and Smart Grid Investments, C. Substation Operations Enhancements, 1. Energy Storage, Project #1 – Utility-Owned Distributed Storage Pilot, p. 21: Update the latest timeline for this project.	23
V. Status of Grid Modernization and Smart Grid Investments, C. Substation Operations Enhancements, 1. Energy Storage, Project #2 – Community Resiliency Pilot, p. 22: Update the latest timeline for this project.	24
V. Status of Grid Modernization and Smart Grid Investments, D. Distribution Field Communication, 1. Modeling and Information Exchange, p. 25: Describe the current barriers the Company faces to full implementation of IEC 61968.	26-27
V. Status of Grid Modernization and Smart Grid Investments, D. Distribution Field Communication, 2. Field Area Network, p. 26: The draft report states: "With all FAN deployments, the Company will continue to look for opportunities to increase its resiliency and operational integrity." Identify what new opportunities are currently being looked at.	28
V. Status of Grid Modernization and Smart Grid Investments, F. Demand Response (DR), 1. Recent Demand Response Developments, p. 39: • If the 2019 IRP isn't available for citation, then the 2019 Smart Grid Report needs to separately describe the Company's latest information on this topic. • Identify any emerging DR opportunities for renewable integration the Company is looking at.	42
V. Status of Grid Modernization and Smart Grid Investments, F. Demand Response (DR), 2. Irrigation Load Control, Future Action, p. 41: • Provide details of the 2017 RFP. • Contrast this Oregon irrigation pilot with similar projects run in other states.	43, Appendix H

Commission Recommendation Description	Page
• In the workshop, some details of future expansion were mentioned: adding Medford and Central Oregon, broadening the time periods, going to an hour ahead, and operating until 2023. Please include this in the report.	
V. Status of Grid Modernization and Smart Grid Investments, G. Distributed and Renewable Resource Enhancements, 4. Distributed Energy Resources (DER) Deployment, Project Description and Analysis, p. 43: • Detail the battery storage costs from the November 2017 contracted research. • Explain when those battery storage cost numbers will be updated. • Describe in detail the formulas and parameters of the Berkshire Hathaway DER evaluation tool.	47-48
V. Status of Grid Modernization and Smart Grid Investments, G. Distributed and Renewable Resource Enhancements, 5. Interconnection Standards and Smart Inverters, Future Action, p. 47: Describe any forthcoming products the Company's suppliers have been describing.	50
Appendix C – Tracking AMI Savings, p. 53: Provide more detail of these results.	56-61

Appendix G – Transportation Electrification Pilot Update

TRANSPORTATION ELECTRIFICATION PILOT UPDATE

MARCH 27, 2019

This document provides a progress update on PacifiCorp's Transportation Electrification Pilot Programs.[23]

Background

In accordance with Senate Bill (SB) 1547, PacifiCorp filed its initial transportation electrification applications on December 27, 2016, proposing three pilot programs anticipated to accelerate transportation electrification in PacifiCorp's Oregon service territory. In February 2017, Public Utility Commission of Oregon staff requested additional information to expedite the review process. In response, PacifiCorp filed a supplemental application on April 12, 2017. On May 31, 2017, PacifiCorp hosted a settlement conference where intervening parties expressed support for, concerns with, and suggestions for improvement of various aspects of PacifiCorp's proposed pilot programs. This resulted in a stipulation that was filed on August 11, 2017 that resolved all matters in the proceeding (Stipulation). All but one intervening party agreed to the terms of the Stipulation. The Commission modified, adopted and approved the Stipulation on February 27, 2018.

The lengthy proceeding resulted in the stipulation and order naming specific dates that did not align with the proposed three year period of implementation. To align timing expectations, PacifiCorp filed a motion to amend order no. 18-075 on February 25, 2019. On March 14, 2019 the Commission amended the order to modify the dates included in the Stipulation. The amended language also modified the Stipulation to require progress updates to the Commission by March 31, 2019 and March 31, 2020 with a report on pilot activities due by June 30, 2021.

The Company began staffing and procurement for these programs after program approval. At this point, competitive requests for proposal (RFP) processes have been completed and vendors have been selected for all program elements, but most pilot elements remain in early implementation stages. There are three programs approved by the commission and summarized in this update. The three programs include:

- Public Charging Pilot
- Outreach and Education Pilot
- Demonstration and Development Pilot

Public Charging Pilot

Through the Public Charging Pilot, PacifiCorp is authorized to construct, own, and operate public electric vehicle charging stations at up to seven locations in its Oregon service

[23] In the stipulation, Pacific Power agreed to "…provide a progress update on all transportation electrification pilot programs and pilots to the Commission by March 31, 2019."

territory. To support this effort, the Company selected two vendors through competitive RFP processes:

- Tower Engineering Professionals (TEP) was selected to perform design, engineering and construction services.
- ChargePoint was selected to provide electric vehicle charging equipment, network services, and operations and maintenance.

Based on final pricing from these RFPs, the Company anticipates it will develop five locations and the Company further expects to begin construction of all sites as early as the end of 2019, however, it's likely that construction at one or more sites may extend into 2020.

The company began looking for potential locations in March of 2018, paying particular attention to areas currently underserved by existing charging infrastructure. An initial list of nine potential sites was shared in June of 2018 with Commission staff based on the criteria of convenience and anticipated use, visibility, availability of necessary electrical service, future-proofing, and permitting. Communities were engaged through PacifiCorp's Regional Business Managers to identify suitable locations to site charging stations. Potential sites were identified within seven communities. Currently the company is working with local governments and property owners in five of the identified communities to finalize locations and property agreements. On September 10, 2018, the Company announced that its first public charging station would be at a newly constructed public park in Klamath Falls. However, the city no longer considers that site viable and the Company is currently working with the city to identify a new location for the charging station.

Table 1. Planned Construction Schedule

Location	Estimated Construction Start
Mill City	Q2 2019
Madras	Q2/Q3 2019
Otis	Q3 2019
Bend	Q3/Q4 2019
Klamath Falls	Q4 2019

Note: While the current schedule is to start construction at each of the sites in 2019, it is possible that construction at one or more sites will be extended into 2020 based on changing and/or unanticipated site conditions.

In accordance with the stipulation and order, on April 19, 2018, the company held a workshop with intervening parties to discuss the objectives of the Public Charging pilot, including the use of time-varying pricing at company-operated electric vehicle charging stations. Participating parties expressed support of time-varying pricing and the beneficial integration of electric vehicle charging load onto the company's system. On July 19, 2018 PacifiCorp proposed rate schedule 60 for company operated electric vehicle charging station service. The rate was designed to align with market funding and encourage efficient equipment and electric grid use. Schedule 60 became effective for service on September 1, 2018.

Table 2. Schedule 60- Company Operated Electric Vehicle Charging Stations

Schedule 60- Company Operated Electric Vehicle Charging Stations		
Level 2 Charging Stations	On-Peak, per minute	1.4 ¢
	Off-Peak, per minute	0.6 ¢
DC Fast Charging Stations	On-Peak, per minute	28.3 ¢
	Off-Peak, per minute	17.7 ¢

Outreach and Education Pilot

The Outreach and Education Pilot primarily consists of four components: customer communications, self-service resources, community events and technical assistance. Progress updates on each component are provided below.

Customer Communications

As agreed to in the stipulation, "Pacific Power will focus Customer Communications expenses, to the extent practical, on promoting and supporting the success of the Company's transportation electrification pilot programs that are approved by the Commission in this docket." To date the majority of communications have focused on publicizing and soliciting applicants for the demonstration and development grants. As the other components of the pilot programs are just ramping up, there has been minimal activity in this area.

Self Service Resources

Through a competitive RFP process, the Company selected Clean Power Research's WattPlan tool. WattPlan performs detailed electric vehicle and home load modeling, electric utility bill, vehicle total cost of ownership and environmental impact estimates. This tool will assist customers interested in electric vehicles in better understanding total lifecycle costs through comprehensive vehicle options, utility bill impacts and incentive calculations. WattPlan is expected to go live on Pacific Power's website in the second quarter of 2019. PacifiCorp is also exploring additional self-service tools but has not yet made additional commitments.

Community Events

Through a competitive RFP process, PacifiCorp selected Forth to coordinate community events, primarily electric vehicle ride-and-drive events. Planning is underway for an estimated four ride-and-drive events throughout Oregon through 2020 along with additional event participation as budget and resources allow.

Technical Assistance

Through a competitive RFP process, PacifiCorp selected C2 Group to provide on-site technical assistance to non-residential customers interested in installing charging infrastructure. This service is offered at no cost to customers. Eligible customers will request custom analysis by submitting an online application, linked to Pacific Power's Website. The buildout of online application and processing is underway with a launch of this service planned for second quarter of 2019.

Demonstration and Development Pilot

The Demonstration and Development Pilot provides grant funding to non-residential customers to help offset the upfront costs of installing electric vehicle charging infrastructure. To make the program more easily understood by customers, PacifiCorp has branded the Demonstration and Development pilot program as the *Electric Vehicle Charging Station Grant Program*. Through a competitive RFP process, PacifiCorp selected Nexant as the independent grant evaluator

Promotion of the Grant program began in August 2018 and is ongoing. Interested customers can sign up to receive notifications about the grant cycles via the website. The Company's Regional Business Managers have been essential in promoting this program to communities and organizations around the state and building awareness about the availability of grant funding. Other organizations including the Oregon Department of Energy, Forth, and Travel Oregon have been helpful in publicizing this grant opportunity.

One full grant cycle has been completed. The first quarterly grant cycle opened to non-residential customers on October 15, 2018 with applications due November 15, 2018. The Company received eight applications and awarded grants to six of the applicants based on the criteria established in the Company's applications and as modified by the stipulation. Awardees are located in Bend, Coos Bay, Roseburg and Medford. All grant recipients plan to install Level 2 charging stations representing an estimated total 28 charging ports with a total PacifiCorp contribution of $262,547. As required by the stipulation, up to 25% of funds in the grant cycle were available to projects focused on fleet or workplace charging. Two of the six applications met the requirements of workplace or fleet charging. Of the $290,000 available in the first grant cycle $72,000, or 17%, was awarded to these two applicants. Up to 25% of funding in each grant cycle will continue to be reserved for these fleet and workplace electrification projects.

The second quarterly cycle opened on January 15, 2019, with applications due on February 15, 2019. A total of thirteen applications were received, but two did not meet the eligibility requirements. Eleven applications are currently under review by the independent evaluator.

Table 3. Remaining 2019 Grant Cycles

Remaining 2019 Cycles	Cycle Opens	Applications Due
Q2	April 15	May 15
Q3	July 15	August. 15
Q4	October 15	November 15

Potential System Impact Study

As agreed to in the stipulation, PacifiCorp developed an initial pilot study of potential impacts of residential electric vehicle adoption. The study proposal was shared with parties in September 2018 and feedback was incorporated into the study design. The study is complete and can be found as appendix A to this document.

Third Party Evaluation

Through a competitive RFP, the Company selected Navigant Consulting to evaluation the pilot programs. Navigant will prepare an evaluation report at the end of the pilot period and results of the evaluation will be used to inform potential program continuation.

Attribution Model and Cost-effectiveness Framework

As agreed to in the stipulation, PacifiCorp is supporting and funding an attribution model and cost-effectiveness framework to inform program evaluation efforts and potential future transportation electrification program development. Since that time, PacifiCorp has worked closely with Portland General Electric to develop a consistent framework for these analysis. On October 17, 2018, PacifiCorp and Portland General Electric staff led a workshop, attended by Commission staff and interested stakeholders, to review background and industry techniques and discuss options for assessing cost-effectiveness and attribution of Oregon transportation electrification programs. Results of those discussions will be incorporated into the Company's third-party program evaluations and future transportation electrification program proposals.

Appendix H.A - Potential System Impact Study

Executive Summary:

In Order 18-075, the Public Utility Commission of Oregon approved PacifiCorp's initial transportation electrification pilot programs, as modified by a stipulation supported by parties in Docket UM 1810. The stipulation includes the following provision:

> PacifiCorp will develop and conduct an initial pilot study of potential system impacts of residential electric vehicle adoption in a selected portion of the Company's Oregon service territory. Before beginning the study, PacifiCorp will share its proposed pilot study objectives, timeline and expected cost with the Stipulating Parties.[24]

In September 2018, the company shared its proposed pilot study objectives, timeline, and expected cost with UM 1810 parties and incorporated feedback received into the design of this study. Through this study, the company sought to understand the potential system impacts of residential electric vehicle (EV) adoption on the primary distribution system. The study accounts for variations in the company's Oregon service territory such as seasonality, geography, demographics and electric vehicle adoption through 2025. The system impacts studied are equipment thermal loading, voltage range and imbalance.

This study utilized a state-level vehicle adoption forecast provided by the Oregon Department of Transpiration, which considers the market share of new electric vehicles growing to 10% by 2025. The study analyzed sensitivities of 20% and 40% higher than the state- level adoption forecast (i.e., 12% and 14% market share by 2025, respectively) with random and clustered electric vehicle adoption. Each scenario was also studied with an additional 30% penetration of private solar generation to understand potential interactions between high levels of electric vehicle and private generation adoption. It is also assumed that customers installing electric vehicle charging will contact PacifiCorp regarding load additions.

The results of this study predict that in some locations, normal load growth will cause isolated system component overloading issues, which will be compounded by additional electric vehicle load. However, PacifiCorp's traditional distribution planning study process is designed to predict overload conditions that require system changes to mitigate. Barring a large increase in the installation of electric vehicle chargers in a short time period, this process will account for and prepare the system for the installation of residential electric vehicle charging.

Most overload conditions created by the installation of residential electric vehicle charging are capable of being mitigated by balancing the feeder load across all three phases. At some single phase locations, the solution to mitigate the overload condition will require the evaluation and modification of the feeder configuration and protection scheme. The addition of private solar

[24] Order 18-075 modified this requirement to include all parties, not only those that supported the stipulation.

generation equal to 30% of the existing load is not projected to significantly impact the conductor overload conditions present due to residential electric vehicle adoption.

Study Scope:

The study assessed three distribution substation transformers and their associated distribution circuits where the substation is categorized as primarily serving urban, suburban, or rural areas. The study starts with the expected loading in 2025 and then is adjusted with the additional increase from the electric vehicle loading sensitivities. The substation distribution transformers and associated distribution circuits are:

Portland (urban)
 Vernon substation, T3747
 5P394 (96% residential), 5P395 (97% residential)
Bend (suburban)
 Shevlin Park substation, T365701
 5D238 (91% residential), 5D241 (91% residential), 5D243 (79% residential)
Klamath Falls (rural)
 Texum substation, T338712
 5L112 (76% residential), 5L113 (12% residential), 5L116 (79% residential)

Methodology:

The study was performed using measured feeder loads and estimated load growth rates through 2025 as a baseline to evaluate the impacts of the ODOT projection of plausible electric vehicle increase to a 10% market share. To study potential impacts of higher levels of residential electric vehicle adoption, sensitivities representing electric vehicle market share of 12% and 14% by 2025 were analyzed. After adjusting the baseline to reflect the impacts of potential new electric vehicle adoption, power flow analysis was performed using time series analysis and peak feeder loading to evaluate the impacts of increased adoption on existing equipment, devices, and voltage delivery. The time series analysis included four one-week periods: the weeks of summer peak load, winter peak load, spring minimum daytime load, and fall minimum daytime load.

Electric vehicle penetration was studied using two different scenarios. The first scenario assumed that the electric vehicle distribution was evenly spread across the entire feeder. The second scenario assumed clusters of electric vehicles in specific areas of the feeders. The randomly spread scenario was modeled as a general load increase equal to the increase in load due to the assumed number of electric vehicle chargers. The clustered scenario was modeled as blocks of load added to feeder taps with a sufficient number of existing customers capable of sustaining the increase of electric vehicle charging. Each clustered scenario was also studied with the addition of private solar generation equal to 30% of the peak load on each feeder.

The study assumed that residents with plug-in hybrid electric vehicles (PHEVs) would use Level 1 chargers with an average peak demand of 3.5 kW and that residents with battery electric vehicles (BEVs) would use Level 2 chargers with an assumed average peak demand of 8 kW.

The assumed registered electric vehicle penetration was based on statewide penetration of electric vehicles and adjusted by individual feeder population. The assumed registered electric vehicle penetration is shown below.

Substation	Feeder	12%		14%	
		BEV	PHEV	BEV	PHEV
Portland- Vernon- Urban	5P394	79	41	95	50
	5P395	53	28	64	34
Bend- Shevlin Park- Suburban	5D238	48	37	58	42
	5D241	52	40	63	45
	5D243	28	21	34	25
Klamath Falls- Texum- Rural	5L112	1	2	2	3
	5L113	0	0	0	0
	5L116	1	3	2	4

Results

Urban:

Summary: The urban Vernon feeders are projected to experience overloaded conductors in all scenarios during normal load growth, random electric vehicle adoption ramping up to 12% market share, clustered electric vehicle adoption at 12% market share, and clustered electric vehicle adoption at 14% market share by 2025.

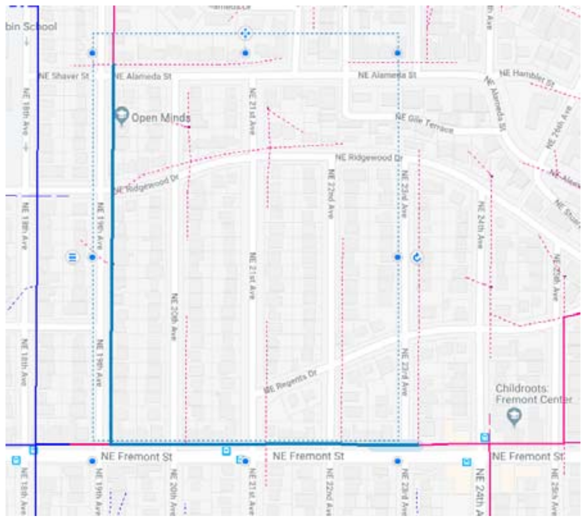
Normal Load Growth: The urban Vernon feeders are projected to experience normal load growth of up to 2.0% over the period ending in 2025. This normal growth rate is modeled to cause conductor overload of up to 118.5% on feeder 5P395 during summer loading conditions at multiple locations. There are no modeled overload conditions due to normal load growth during winter, spring, or fall loading conditions.

12% Electric Vehicle Market Share: The addition of electric vehicle charging to this feeder is modeled to increase this overload to 124.7% by 2025. Random electric vehicle adoption is modeled to overload one section of conductor on 5P395 to 100.5% during summer loading conditions. Clustered electric vehicle adoption in this scenario is modeled to overload one section of conductor on 5P395. All sections of overloaded conductor can be brought into tolerances with targeted phase balancing to move the load to under-loaded phases.

Random electric vehicle adoption in this scenario is modeled to overload the conductor between facility points 01101001.0236009 and 01101001.0236001 on feeder 5P395 to 100.5% during summer loading conditions.

Clustered electric vehicle adoption in this scenario is modeled to overload the section of #2/0 copper on feeder 5P395 beginning at facility point 01101001.0237203 and extending to facility point 01101001.0237003 to 111.3% during winter loading conditions. The addition of private solar generation is expected to decrease the overload to 109.1% in the case of 12% electric vehicle registration and 118.6% in the case of 14% electric vehicle registration. This section of conductor is shown in Figure 1.

Figure 1. Potentially Overloaded Conductor, FP 01101001.0237203 to 01101001.0237003



14% Electric Vehicle Market Share: Clustered electric vehicle adoption ramping up to 14% market share by 2025 is modeled to overload four additional sections of conductors on 5P394 and 5P395.

- The span of 336 ACSR conductor on feeder 5P395 beginning at 0101001.0236009 to 01101001.0236001 is modeled to be overloaded to 108.2% during winter loading conditions. The addition of private solar generation may reduce this overload to 106.4%. This span of conductor is shown in Figure 2.
- The section of 336 AAC conductor on feeder 5P395 beginning at facility point 01101001.0237305 to 01101001.0237202 is modeled to be overloaded to 107.1% during winter loading conditions. The addition of private solar generation may reduce this overload to 105.2%. This section of conductor is shown in Figure 3.
- The 5P394 feeder getaway of 1000 kcm aluminum is modeled to be overloaded to 102.6% during winter loading conditions. The addition of private solar generation may reduce this overload to 101%.
- The section of 4/0 copper conductor on feeder 5P394 beginning at 01101001.0236309 to 01101001.0236310 is modeled to be overloaded to 107.2% during winter loading conditions. The addition of private solar generation may reduce this overload to 105.4%. This section of conductor is shown in Figure 4.

Figure 2. Potentially Overloaded Conductor, FP 01101001.0236009 to 01101001.0236001

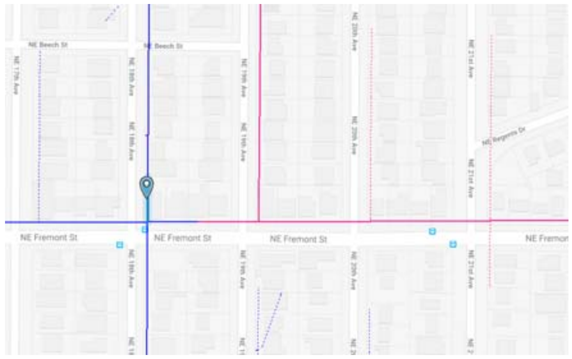
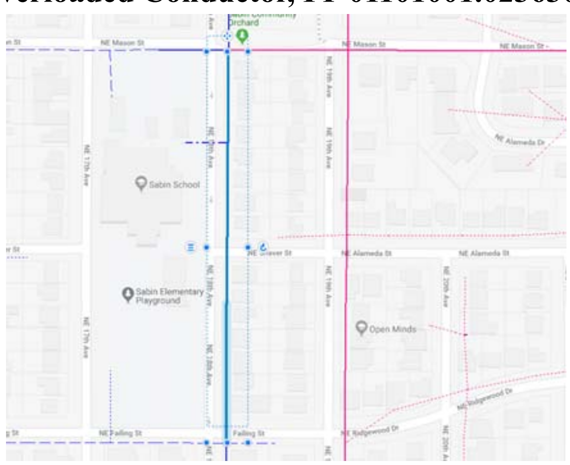


Figure 3. Potentially Overloaded Conductor, FP 01101001.0237305 to 01101001.023720

Figure 4. Potentially Overloaded Conductor, FP 01101001.0236309 to 01101001.0236310



<u>Suburban:</u>

Summary: The suburban Shevlin Park feeders are projected to experience overloaded fuse conditions during normal load growth, clustered electric vehicle adoption ramping up to 12% market share, random electric vehicle adoption ramping up to 14% market share, and clustered electric vehicle adoption at 14% market share. Overloaded elbow conditions are also projected on feeder 5D241 during clustered electric vehicle adoption of 14% market share.

Normal Load Growth: The suburban Shevlin Park substation is expected to experience normal load growth of up to 5.0% on feeder 5D243 while experiencing lower growth rates of 0.5% on feeders 5D238 and 5D241 over the period ending in 2025. The normal load growth on 5D243 is not expected to lead to overloading issues by 2025. This normal load growth is expected to lower the peak load voltage to 94.8%, which is outside of ANSI Range A. Normal load growth is modeled to cause overloading up to 128.7% at three fuse locations on 5D238 and 5D241 during summer and winter loading conditions.

12% Electric Vehicle Market Share: The random and clustered electric vehicle charging scenarios were shown to cause single phase overloading at various additional fuse and elbow locations on feeders on 5D238 and 5D241. Extreme clustered electric vehicle charging on feeder 5D238 was shown to increase load up to 150% of the rated capacity of some devices during winter loading conditions. 5D243 was not shown to have any overload issues that are the result of electric vehicle charging.

When random electric vehicle is modeled, it is shown to cause the single phase overload of the 200A elbows to 100.3% at facility point 01418012.0063782 during summer loading conditions. This is modeled to increase to 102.1% with the random electric vehicle adoption of 14% of registered vehicles. This location is shown in Fig 5.

Clustered electric vehicle adoption in this scenario is modeled to cause the single phase overload at three fuse locations.

- The 100T fuse at 01417011.0252800 on feeder 5D238 is expected to be overloaded to 118% during winter loading conditions and 130.5% with the clustered electric vehicle adoption of 14% of registered vehicles. This overload is modeled to be 109.3% during summer loading conditions with electric vehicle adoption if 12% of registered vehicles and 120.1% with electric vehicle adoption of 14% of registered vehicles. The addition of private solar generation may reduce the overload by 1.1% for each scenario. This fuse feeds a three phase tap and the overload condition can be mitigated by balancing the load beyond the fuse. This fuse location is shown in Figure 6.
- The 80E fuse at facility point 01417011.0247281 on feeder 5D238 is modeled to be overloaded to 134.4% during winter loading conditions. The addition of private solar generation may reduce the overload by 1.4% for this scenario. This fuse feeds a single phase tap that would not benefit from load balancing. An evaluation of the fuse coordination and normal open point beyond this fuse would need to be performed to determine the ideal solution to this overload condition. This location is shown in Figure 7.
- The 100T fuse at 01417012.0317502 on feeder 5D241 is modeled to be overloaded during summer loading conditions to 106.3% in this scenario. The addition of private solar generation is expected to decrease this overload by 1.8%. This fuse feeds a single phase tap that would not benefit from load balancing. An evaluation of the fuse coordination and normal open point beyond this fuse would need to be performed to determine the ideal solution to this overload condition. This fuse location is shown in Figure 8.

Figure 5. Potentially Overloaded Elbow, FP 01418012.0063782

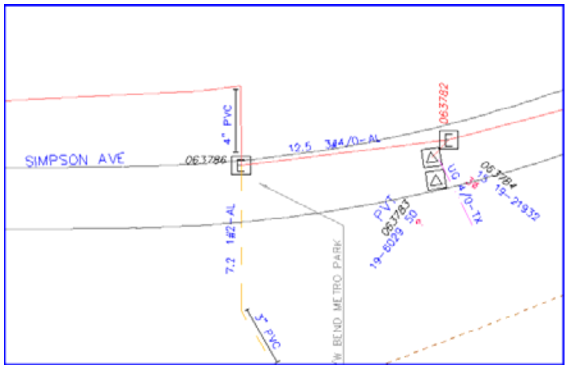


Figure 6. Potentially Overloaded Fuse, FP 01417011.0252800

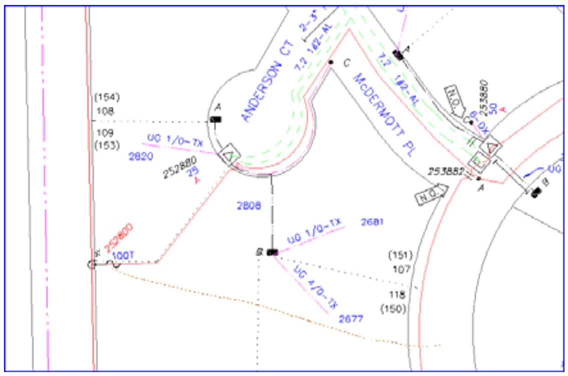


Figure 7. Potentially Overloaded Fuse, FP 01417011.0247281

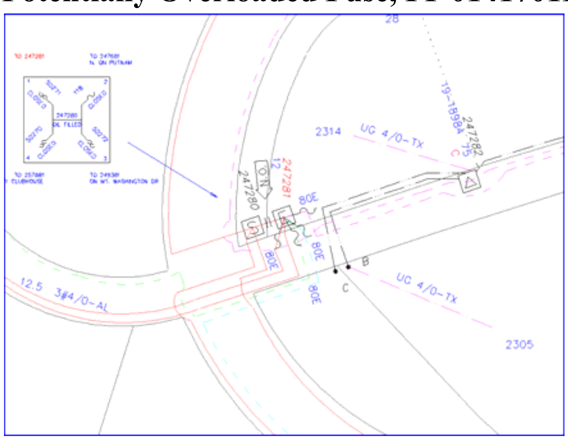
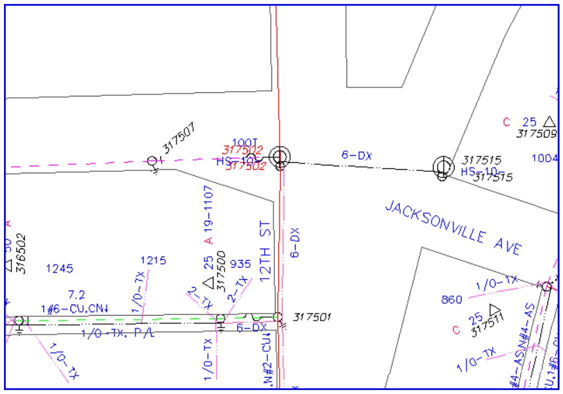
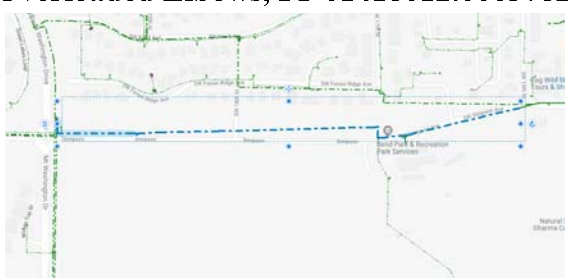


Figure 8. Potentially Overloaded Fuse, FP 01417012.0317502



14% Vehicle Adoption: Clustered electric vehicle adoption ramping up to 14% market share is modeled to cause an overload condition of up to 102.1% on 200 A elbows between facility points 01418012.0063782 and 01418011.0019782 during summer loading conditions on B phase. This overload condition would be able to be corrected by balancing the load beyond the elbows. The addition of private solar generation may reduce this overload condition to less than 100%. This section of line is shown in Figure 9.

Figure 9. Potentially Overloaded Elbows, FP 01418012.0063782 to 01418011.0019782



Rural:

The rural Texum substation load examined in this study does not expect any load growth over the period ending in 2025. The assumption of between seven and 11 residential electric vehicle chargers connected to these feeders is not expected to cause any loading or voltage issues by 2025.

Appendix H – Irrigation Load Control Information/Comparison

Program Parameters	Oregon Pilot - current	Oregon Pilot as proposed in Advice 19-008	Rocky Mountain Power – Idaho	Rocky Mountain Power – Idaho real time pilot	Rocky Mountain Power – Utah	Idaho Power Irrigation Peak Rewards
Eligible Customers	Irrigation Customers on Schedules 41 or 48 in and around Klamath Falls.	Irrigation customers on Schedules 41 or 48 in and around targeted areas posted on company web site.	Irrigation customers on Schedule 10	25 Schedule 10 irrigation sites associated with one grower	Irrigation customers on Schedule 10	Irrigation customers (rate schedule located during search of publicly available marketing materials)
Program Period	Week including June 1 through week including August 15. Voluntary period: August 15 September 30	Week including June 1 through week including September 1. Voluntary events eliminated.	Week including June through week including August 15. Voluntary events through September 30.	Week including June through week including August 15.	Week including June through week including August 15. Voluntary events through September 30.	June 15 to August 15
Program Hours	Weekdays, 12:00 p.m. to 8:00 p.m. Pacific Time.	All days, 12:00 p.m. to 10:00 p.m. Pacific Time.	Weekdays 12-8 PM Mountain time	During control season 24 hours a day for all days	Weekdays 12-8 PM Mountain time	Mon-Saturday. 1-9 PM (excludes 4th of July holiday)
Dispatch Limitations	52 hours per year, 20 events per year, up to 4	No changes	Up to 4 hours/event, 12 hours/week, 52	Up to 60 minutes, same limitations, event frequency is	Up to 4 hours/event, 12 hours/week, 52	Minimum of 3 events/season, no more than 4 hours/event,

	hours per event.		hours/season	expected to be less than regular program	hours/season	no more than 15 hours/week, not to exceed 60 hours/season.
Dispatch notification	Day ahead	Day ahead and hour ahead	Day ahead. By 5 PM day before an event	Real time notification	Day ahead. By 5 PM day before an event	Four hours' notice
Incentive Rate	Estimated at $23-$27/kw per year. The program vendor may adjust the incentive rate based upon the needs of the program.	Day ahead at $18/kW per year Day ahead (2018 participants and any new participants prior to 2019 approval) at $23/kW per year for at least the 2019 season Hour ahead at $30/kW per year	$23 - $25/kw per year	$23 - $25/kw per year	$23 - $25/kw per year	Fixed incentive payments of $5/billing kW and $0.0076/billing kWh AND variable incentive per event kWh after three events/season.
Opt-Outs	Participants may opt-out of dispatches. Opting out will lower participation payments proportionally.	No change	Participants may opt-out of dispatches. Opting out will lower participation payments proportionally.	Participants may opt-out of dispatches. Opting out will lower participation payments proportionally.	Participants may opt-out of dispatches. Opting out will lower participation payments proportionally.	Up to five times/season. Opt out fees (per kW) are applied.
Incentive Payments	The incentive	No changes in	The incentive	The incentive	The incentive	Fixed incentive

	payment is calculated at the end of the irrigation season and paid to each participant in the Fall. Participant incentives will be determined by multiplying the average load (kW) a customer can reliably shut-off during program hours by the incentive rate, adjusted for event participation (opt-outs).	payment timing or calculations. Payments will be different by Dispatch Notification option selected.	payment is calculated at the end of the irrigation season and paid to each participant in the Fall. Participant incentives will be determined by multiplying the average load (kW) a customer can reliably shut-off during program hours by the incentive rate, adjusted for event participation (opt-outs).	payment is calculated at the end of the irrigation season and paid to each participant in the Fall. Participant incentives will be determined by multiplying the average load (kW) a customer can reliably shut-off during program hours by the incentive rate, adjusted for event participation (opt-outs).	payment is calculated at the end of the irrigation season and paid to each participant in the Fall. Participant incentives will be determined by multiplying the average load (kW) a customer can reliably shut-off during program hours by the incentive rate, adjusted for event participation (opt-outs).	payments appear to be a bill credit. Variable incentive payments are paid by check within 45 days from end of program season.

Appendix I – DER Alternatives Tool User Guide Excerpt

DER Alternative Solutions Template - USER GUIDE

The user guide is a short synopsis on how to use the DER Alternative Solutions Template. Information on calculations, data, and cost estimates is available on this tab as a guide as you complete the template. Utilizing DER requirements calculated in the template, the planning engineer will also need to study and identify any needed system improvements required to integrate the DER into the system, i.e. substation/distribution improvements including improvements to mitigate any adverse effects the DER alternative and their costs. These costs can be added to the template on the solar or battery storage tabs as needed.

Results Summary

This tab is the starting point to identify the peak load and facility rating constraints that are driving the need for a potential traditional or DER alternative solution. From this information, a target loading (typically 90%) of the facility rating is determined. The next steps for analyzing the potential feasibility of a DER alternative are to proceed through the next tabs of the spreadsheet and provide information such as a projected peak daily load profile and solar output data for the site. The Results Summary tab also gathers key information from other tabs to present a synopsis of the initial screening to determine the feasibility of DER alternatives as solutions to the loading or voltage issue being investigated for a capital improvement.

Facility Load Data

This tab is used to add hourly load curve data for at least one day under "Existing Peak mm/dd/yyyy." If it is desired to review additional peak days and take an average, columns can be added to accomplish this. If you have load at other increments such as 10 min or 15 min data, use a separate Excel file to convert the data to hourly data. The load profile for Projected Peak is scaled based on % Increase compared to Existing Peak. The Projected Peak is the peak load when the load equals or exceeds the loading level that a Planning Criteria violation occurs.

PVWatts Data

This tab is used to populate the annual solar data that is obtained from running NREL's PVWatts Calculator Internet application for the site of the potential solar installation. The full annual data for the site is added to this tab. This base data is used on the following tab.

PVWatts Graph

This tab uses data from the PVWatts Data tab and averages the hourly monthly solar data for the months of July and August to create one 24 hour solar profile. If the peak for the facility being evaluated typically occurs outside the July and August window, the average calculations can be modified as needed for the specific site. (e.g. winter peaking load, fall peaking load). The graph shows output based on a percentage basis of the solar installation's MWdc nameplate. This graph is representative output for a potential solar installation and is used in conjunction with the daily load curve to determine the size of the installation needed to reduce the net load and solar output to below the target loading of the facility.

Solar Analysis

This tab is used to compare the hourly load profile and the solar output profile to determine if a solar DER alternative can result in lowering the load on the facility to the target 90% loading threshold.

1. To determine the minimum initial size of the solar installation to analyze first, it is calculated as: Min Solar Size (MW) = (Difference between Projected Peak and Target 90% Loading Threshold) x (Ratio DC Solar Panels to AC Inverter Output) / (Maximum %MWdc Nameplate Output).
2. Review the Solar Alternative graph to determine if a different size solar installation will result in the Net Load being below the Facility Rating Threshold.
3. If the Solar Alternative cannot meet the Facility Rating Threshold, then a Solar Only Alternative is not feasible.

Solar Summary & Cost Estimate
This tab is used to estimate the complete costs of a solar installation determined by the results of the Solar Analysis tab. Estimates for the solar array and inverter, land costs, and interconnection costs (substation and distribution system infrastructure required to connect the solar installation to the local utility grid) are included.

Battery Storage
1) If for some reason battery storage is not viable, regardless of cost, indicate in step one and briefly describe why it is not feasible.
2) The centralized energy storage requirements are calculated based on inputs on the 'Curve Data' tab of this workbook. The basic requirements for centralized energy storage (CES) include an MVA size for the peak discharge needed, and MVAhr for the energy needed. The MVA size is calculated by taking the forecasted load peak minus 90% of the loading constraint. The MVAhr requirement is calculated by determining the area under the forecasted load profile, bound by again 90% of the loading constraint. 90% is a management directive for the DER benefit expected. Verify the accuracy of the calculations by comparing the Loading Analysis chart and the CES requirements. Battery sizes (MVA and MVAhr) are rounded up for estimating purposes.
3) Based on the CES requirements, the template will calculate an estimate for the battery, installation, and ancillary costs. A maintenance cost is also included, as well as land costs based on typical battery sizes and information from the summary tab. The planning engineer will need to determine the scope of the distribution and/or substation interconnection costs associated with installing battery storage and its location. The scope will inform the subsequent distribution/substation costs. The planning engineer will enter those costs into their respective distribution/substation cost cells.

If the battery size is not contained in the cost summary table, no cost will be returned, and the battery storage alternative is considered not feasible. Go to step 1 and document as 'No' not feasible with reasoning that required battery size is not a viable option. In addition, if there is insufficient off-peak charging time, cell J44 will return a "NO" and again go to step 1 and document as 'No' not feasible.

Solar & Battery Analysis
This tab is used to compare the hourly load profile, the solar output profile, and the needed battery output profile to determine if a combined solar and battery DER alternative can result in lowering the load on the facility to the target 90% loading threshold.

1. This analysis starts with the same MW size solar installation as the Solar Only Alternative since that MW size reduced the facility loading when the solar output was reasonably high.
2. This analysis estimates the capacity and energy of a battery needed to offset the Solar Deficit MW and Solar Deficit MWh values that the Solar Only Alternative could not provide.

3. The MW and MWh values estimated for the battery are rounded up to the next whole MW and/or MWh size. An hour duration that the battery is needed is also estimated. These values are used to create a cost estimate on the Solar & Battery Cost tab.
4. Review the Solar and Battery Alternative graph to determine if the calculated solar and battery installations result in the Net Load (orange) being below the Facility Rating Threshold (Green).
5. If the Solar and Battery Alternative cannot meet the Facility Rating Threshold (Green) and also provide enough capacity to charge the Battery, then a Solar and Battery Alternative may not be feasible.

A copy of the tab can be made to try different sized solar and battery installations that may be feasible and at a lower estimated cost. For combined installations where the battery charging time was adequate, smaller MW solar installations with larger MW and MWh battery installations can be modeled to potentially determine a potential alternative with a lower overall cost. For combined installations where the battery charging time was not adequate, larger MW solar installations to reduce the load on the transformer can be modeled to potentially determine a potential alternative.

Solar & Battery Summary & Cost Estimate
This tab is used to estimate the complete costs of a solar and battery installation determined by the results of the Solar & Battery Analysis tab. The calculations are the same as used on the individual Solar Cost and Battery tabs and totaled for a combined estimate.

Demand Side Management
Demand Side Management - PacifiCorp
1) At PacifiCorp, given the regulatory approvals and administrative requirements surrounding typical DSM applications, at least three years is needed to plan and implement a DSM solution. If the proposed project issue year is less than three years, then the DSM alternative is considered not feasible.. If the issue year is more than 3 years, proceed.
2) Enter the requested data sets for the equipment that would be affected by a reduction in load, e.g. for a substation transformer loading issue, enter the number of customers served by that transformer, the customer class, and MW reduction needed each year to stay below the loading constraint. This information will be utilized to estimate the available MWs of DSM served by that transformer.
3) Enter data from look up tables to finish the calculation.
4) Compare the available kW on the equipment with constraint issue to the needed reduction in load to stay below the constraint. If the values are within +/- 25% at any point along the accumulation outside of three years, further evaluation will be required by the DSM team. Contact Jeff Bumgardner in Pacific Power or Clay Monroe in Rocky Mountain Power. The available kW and costs information will be transferred to the summary tab. Enter 'Yes' that this option is feasible in cell J43. If the values are greater or less than 25%, this option is not feasible, enter 'No' in cell J43.

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