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VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: UM 1667—PacifiCorp's Reply Comments

PacifiCorp d/b/a Pacific Power provides the following reply comments in response to comments from Commission Staff (Staff) and the Oregon Department of Energy (ODOE) in regards to PacifiCorp's 2017 Annual Smart Grid Report (Report) filed with the Public Utility Commission of Oregon on August 1, 2017.

I. Stakeholder Process

The Commission adopted non-substantive smart grid reporting requirements to ensure that "utilities are systematically evaluating promising smart-grid technologies and applications, that the Commission is kept apprised of utilities' progress, and that stakeholders, Commission Staff, and the Commissioners have an opportunity to provide input into utility evaluations of smart-grid technologies and applications, as well as their plans for smart-grid investments."[1] Recognizing that "smart grid is comprised of many technologies, in different stages of development and affordability," the Commission has expressly declined to require utilities to submit comprehensive "smart grid plans."[2]

On July 17, 2017, PacifiCorp held a stakeholder workshop to receive feedback, comments and questions from stakeholders with regard to the company's draft 2017 Smart Grid Report that was distributed to stakeholders on June 1, 2017. PacifiCorp appreciates the time and attention of the stakeholders attending these workshops and the questions and comments. These interactions, along with the written comments provided by parties on the draft report provided valuable feedback to assist PacifiCorp in preparing a thorough and robust 2017 Smart Grid Report.

On August 1, 2017, PacifiCorp submitted its 2017 Annual Smart Grid Report in compliance with Order No. 12-158,[3] incorporating feedback from stakeholders. In November, 2017, Staff and ODOE provided comments on the Report from PacifiCorp. PacifiCorp provides these reply comments in response to the comments from Staff and ODOE.

[1] *In the Matter of Public Utility Commission of Oregon Staff Recommendation to Use Oregon Electricity Regulators Assistance Project Funds from the American Recovery and Reinvestment Act of 2009 to Develop Commission Smart Grid Objectives for 2010-2014,* Docket No. 1460, Order No. 12-158 (Order No. 12-158) (May 8, 2012).
[2] Order No. 12-158 at 2.
[3] Order No. 12-158 at 1.

II. PacifiCorp's Response to Informal Written Comments from Staff and ODOE

The final Report, filed on August 1, 2017, included Appendix A that provided a high-level table summary of the comments received from Staff and ODOE and PacifiCorp's corresponding responses and a cross-reference to the location of the discussion of these responses in the Report.

III. PacifiCorp's Response to Staff's Formal Comments

PacifiCorp's reply comments are organized by responding to Staff following the structure outlined in its comments. Staff's comments are repeated and provided in italics, with the company's response in regular font.

Recommendation 4: *Company to continue to apprise the Commission of the success, or lack thereof, of its remedial action scheme in the form of redundant relays.*

In the 2017 report, the Company states that the remedial action scheme of installing redundant relays as an alternative to a combination of a thermal replicating relay and dynamic line rating is in service and functioning as designed, and no future action is anticipated.

Staff requests that the Company state in its reply comments under what circumstances a thermal replicating relay and/or dynamic line rating would provide benefits that outweigh the considerable cost difference in relation to a redundant relay scheme.

PacifiCorp Response

Dynamic line rating and/or thermal replicating relay installations are more systematically complex installations with more in-depth maintenance requirements and are more prone to failure compared against redundant relays. However, these systems do provide increased transmission capacity when weather is more favorable than the standard line rating conditions. For the Soda Springs installation, PacifiCorp stated redundant relays in a remedial action scheme were expected to be over $1.2 million dollars less expensive than the dynamic line rating and/or thermal replicating option. PacifiCorp will build the most cost effective option for customers, so a dynamic line rating and/or thermal replicating installations must provide benefits that exceed the substantial difference in cost and maintenance obligations, and in reliability between the installed options.

The main goal of dynamic line ratings and/or thermal replicating relays is to transmit substantially more power across the line than would otherwise be allowed with the traditional static line rating. Generation rich areas, which regularly reach the thermal constraints of lines, could receive operational benefits in excess of the substantial cost difference between system designs. Theoretical examples of this cost savings could be dynamic line ratings and/or thermal replicating relays for transmission paths in wind generating areas of Wyoming or solar generating areas of Utah to move more power when the ambient conditions are cooler or wind speeds are higher than the conservative line rating conditions the base case allows.

Recommendation 5: *Company to provide a comprehensive narrative explaining its developments, or lack thereof, both past and present, with Peak Reliability and WECC and its decision to stop its transfer of PMU data to Peak Reliability. The Company should also follow through with its commitment to address ODOE's interest in seeing a discussion of lessons learned from identifying and analyzing system vulnerabilities and disturbances. ODOE was also interested in information in future smart grid reports on synchrophasor data being used to increase real-time situational awareness for transmission operations.*

The Company detailed its decision to stop transfer of PMU data to Peak Reliability explaining that it has robust EMS and SCADA systems that offer real-time system data every two seconds for maintain situational awareness. PacifiCorp goes on to state that after several years in the program, the tools have yet to produce timely data that can be used to make real-time decisions for PacifiCorp's transmission operations. The program also faced interface and communication issues connecting to Peak Reliability. PacifiCorp stated that its biggest lesson learned about working with PMU's was that quality data is difficult and costly to maintain. The Company states that it may restart the data stream to Peak Reliability in the future depending on tools available.

The Company plans to continue to collect PMU data at its central office, and has plans to expand PMU coverage as part of the NERC standard MOD-033-1, and includes a table of locations identified for equipment in Appendix C. PacifiCorp also plans to install PMUs at large wind, hydro, and natural gas generating facilities. The scope and estimate were estimated to be complete in July 2017, and design and construction of the systems is planned for completion in 2018.

Staff requests that the Company update these plans in reply comments, and provide the scope and cost estimates for expanded PMU coverage, if available.

PacifiCorp Response

The overall MOD-033/PRC-002 plan PMU/Phasor Data Concentrator (PDC) bids were not due back until December 7, 2017, from the PDC vendors, so the final planned solution will not be known until the end of the year. The Report has a list of the locations of the PMUs located in Appendix C. A new employee has been hired to perform the data mining once the data is streamed to the PDCs, but PacifiCorp's expectation is that the streaming will not begin until second quarter 2018. The originally forecasted date for estimate returns was in July 2017; however, due to some scope changes, this date was pushed out to December 2017. An updated list of sites will be included in the 2018 Smart Grid Report.

The current scope for sites are the installation of SEL-2240 Axion PMU system with protection class CT/PT modules. Every location is time synced with a GPS clock. PacifiCorp is not using local PDC and therefore the maximum storage size on the device is 2GB for storing dynamic based event COMTRADE records.

Site costs for currently installed sites (currently six sites complete, all generation assets) total (equipment, drafting, engineering, and install) approximately $150,000, or approximately $25,000/site. PacifiCorp is currently installing the same PMU design for the four bulk-electric-system-connected hydro plants (Merwin, Swift, Yale, and JC Boyle) and it will be close to the same cost. PacifiCorp's complete project cost estimate for MOD-033/PRC-002 completion is $7.3 million, inclusive of communications system upgrades in order to retrieve local PMU data as well as both Pacific Power and Rocky Mountain Power service areas.

Recommendation 6: *Company to provide an update to its irrigation load control pilot and update the table on page 37 of the 2016 Smart Grid Report including Oregon data when it is available.*

In 2017, no new customers will be added to the pilot program. However, one customer who signed up for the program in 2016 was not enabled until 2017. One two-hour event occurred since the last Smart Grid Report, on August 19, 2016, where 281 kW of available capacity was called on with 100% participation from the customers.

The Company will issue a Request for Proposals (RFP) in 2017 for load control services. Following the 2017 season, the Company will reassess the pilot to decide the future of the load control program.

Staff requests that the Company state in its reply comments why no new customers will be added to the program in 2017. Staff also requests that the Company elaborate on the criteria that will be assessed in determining the future of the program, and how the RFP may or may not influence that assessment.

PacifiCorp Response

A key finding from 2016 program delivery was that there is a disconnect between the cost to deliver this small scale pilot and the existing pricing structure with the program vendor. Enrolling and enabling new customers generates additional administrative costs. Schedule 105 contains language to manage participation, which PacifiCorp used to manage 2017 costs while additional delivery options were assessed. The program criteria that will be assessed in order for the program to move forward includes: grower acceptance, delivery costs, effectiveness of the current program design and availability of alternate program designs including ability to expand customer counts or geographically. Information from the RFP, specifically customer responses, will provide information relevant to one or more of these criteria through revealed preferences.

Recommendation 7: *Company to provide a summary of its review to investigate linking distribution devices to its OMS system and energy management system (EMS).*

The SCADA Monarch EMS was commissioned at PacifiCorp in April of 2016. The Company has determined that integrating the communicating faulted circuit indicators (CFCI) with the EMS is not the preferred solution. Rather, the Company believes the CFCI devices should be visible to the Company's Distribution Management System (DMS). The Company plans to upgrade its DMS to a newer version beginning in fall of 2018, which includes capability to integrate CFCI devices.

Staff requests that the Company state in its reply comments the feasibility of linking EMS and DMS systems and any advantages or disadvantages in doing so. Staff also requests that the Company address whether both systems follow IEC 61968 standards for information exchange.

PacifiCorp Response

The communication between the DMS and EMS systems could be accomplished using a current industry standard method called Inter-Control Center Protocol (ICCP or IEC 60870-6/TASE 2). ICCP allows the exchange of real time and historical power system information including status and control data, measured values, scheduling data, energy accounting data and operator messages. Functional working experience and knowledge presently exist within the company's EMS support teams. System linking would require an ICCP server to reside at each end with a dedicated communication path configured appropriately, depending if the communication path exits a controlled (CCA) electronic security perimeter (ESP). After establishing Ethernet communications, there would be mapping on both sides to a common ICCP object ID name. Status, analog data is efficiently transferred using this method. PacifiCorp is presently using ICCP for communications to all neighboring utilities, the Energy Imbalance Market and PacifiCorp's own outage management system, CADOPS.

Potential advantages of linking the systems are: an established industry standard, which is existing and in use at PacifiCorp, and experience/knowledge presently within the company. The potential disadvantage of integration: dedicated network cost, hardware cost (this cost is affected by physical separation – if systems are in the same CCA/ESP location then costs are reduced). PacifiCorp is currently reviewing IEC 61968, which is currently under development, and will define the company's adherence to the standard at a time-to-be-determined.

Recommendation 8: *If applicable, Company to provide an update on any field area network or communication functionality implementation.*

The Company is deploying Fuse Saving devices that provide two-way communication on the distribution system. The devices provide rapid detection of system functionality, which reduces momentary interruptions.

The Company has two pilot projects in development. One project utilizes FuseSavers and CFCI, and the other project utilizes LineScope. If the pilot installations show positive results in the next 18-24 months, their installations will become standard practice. The Company is also observing data from newly upgraded substation devices and line reclosers for possible expansion to other locations.

Staff requests that the Company state in its reply comments what functionalities of LineScope the Company hopes to utilize, and what positive results would lead to installation being standard practice.

PacifiCorp Response

PacifiCorp anticipates that LineScope devices will be able to be used to act as localized SCADA devices, deployable within the network areas where operators are currently "blind" to how the system is operating: such as whether energy is flowing, fault operations may have occurred, or power quality waveforms are abnormal.

With this information, operators will be able to identify when anomalies in system energy flows have occurred, rapidly reconfigure the network, and restore power where additional sources may exist. If no additional sources exist, they will be in a position to restore the network more quickly by dispatching individuals to specific locations, rather than requiring the responding individuals to patrol entire lines looking for evidence of faults. This functionality is similar to that provided through advanced relays and other devices, but have cost advantages that are expected to allow PacifiCorp to increase its usage of the devices.

As the company gains familiarity with LineScope devices, it is expected they will become the standard approach for adding visibility to the electrical transmission network, as cost schedules allow.

Recommendation 11: *Company to provide DER analysis, including how it has utilized the transmission and distribution planning tool.*

The Company deployed a DER screening tool for transmission and distribution planners to compare DERs to traditional solutions. The tool is an alternatives template created in a Berkshire Hathaway Energy cross-platform initiative that screens for solar, energy storage, and demand-side management feasibility and cost comparison. The Company is waiting for the conclusion of the RVOS (UM1716) and energy storage (UM1751) dockets to populate the tool with each technology's respective values. The Company has also partnered with ETO to determine whether customer-cited energy efficiency technologies have the ability to improve system operation during specific locational peak hours. The Company anticipates that future proposed system reinforcements will include DER solutions as part of system analysis.

Staff requests that the Company summarize exercises where DER was considered as an alternative to traditional solutions, the results of the exercises, and what hurtles, if any, there are to implementing the tool on a permanent basis.

PacifiCorp Response

PacifiCorp has implemented the Distributed Energy Resource (DER) screening tool on a permanent basis in the 10 year planning cycle for substation capacity improvements and distribution feeder projects over $1 million. Substation capacity projects and larger distribution upgrade projects were focused for their higher chance of being effective investments. Smaller distribution projects experience diminishing returns since many costs do not substantially decline in smaller installations. In PacifiCorp’s 2017 10 year planning analysis, 18 projects were screened using the DER tool. The company screen for DER systems designs include solar, storage, solar plus storage, and demand-side managements. PacifiCorp has recently received updated energy storage prices from DNV GL and will incorporate this updated pricing into the DER tool.

Additional Recommendations:

Staff requests that the Company state in its reply comments whether smart inverter communication and functionality has been explored for integration with the AMI, EMS, and/or DMS systems.

PacifiCorp Response

Electric Power Research Institute and PacifiCorp are embarking on a project that will include smart inverter data capacity analysis and exploring best methods of communicating with smart inverters. This project will identify existing hurdles and indicate potential methods for integrating smart inverters into the Automated Metering Infrastructure (AMI) system, how best to accomplish the communication signal conversion likely necessary, and what functionality would be achievable with integration.

One of the goals of the Company's Distribution Automation Feasibility study was to identify circuits containing critical loads/infrastructure. Therefore, Staff requests that the Company state in its reply comments what distributed automation or other smart grid technology would increase reliability on these critical circuits, and what plans, if any, there are to implement such technology.

PacifiCorp Response

The Distribution Automation Feasibility study identified some of the 35 circuits containing critical loads/infrastructure that would experience increased reliability from distribution automation. PacifiCorp is implementing an initial deployment of distribution automation in the Lincoln City area. This initial deployment location was chosen because it will be serviced by AMI and showed one of the highest potential improvements for a distribution automation system. If this initial deployment is successful, more locations serviced by AMI may benefit from a distribution automation scheme in the future. PacifiCorp will gather information from this initial deployment to inform any potential future deployments.

Staff requests that the Company provide in its reply comments an update on the VaultGard Portland Low Voltage Secondary Network Project.

PacifiCorp Response

At the time of the 2017 Report, PacifiCorp was in the process of establishing an RFP to install a network monitoring system in the Portland underground network. The RFP process has been completed, and Eaton has been awarded the position of contractor. They are subcontracting the construction through Christiansen Construction. PacifiCorp is currently performing engineering and material procurement for the project and exploring how to import the resulting data into EMS. The company plans to install 75 new VaultGard systems as part of this project. The project in-service date is scheduled for November 1, 2018.

IV. PacifiCorp's Response to ODOE's Formal Comments

The comments received from ODOE on PacifiCorp's Annual 2017 Smart Grid Report were specifically related to AMI deployment and subsequent customer-facing program development, transmission enhancements to comply with North American Electric Reliability Corporation (NERC) reliability standard MOD-033-1, continued development of energy storage analysis and tools, and demand response programs.

ODOE's recommendations all focused on PacifiCorp's future smart grid reports, requesting:

- The company perform financial modeling to help prioritize future actions for AMI,
- Further discussion on PacifiCorp's progress in hardening the technology and improvements that provide cost-effective methods to improve data quality,
- Additional information in future smart grid reports on the evaluation process used by the company in choosing deployment locations for synchrophasors that will provide the data critical for compliance with NERC reliability standard MOD-033-1,
- More detailed narrative in future smart grid reports on methods the company is utilizing to value energy storage and how these tools are working to streamline the evaluation process, and
- Further discussion of market developments

PacifiCorp takes note of all of the recommendations made by ODOE and will continue to track and report all progress the company undertakes to address the recommendations in future smart grid reports, similar to the tracking mechanism included in PacifiCorp's 2017 Annual Smart Grid Report, Appendix A.

V. Conclusion

PacifiCorp appreciates Staff's and ODOE's comments, the opportunity to respond to them, and to present the 2017 Report to the Commission and other Oregon stakeholders.

If you have questions about these comments, please contact Jason Hoffman, Regulatory Projects Manager, at (503) 331-4474.

Sincerely,

Natasha Siores
Regulatory Affairs Manager